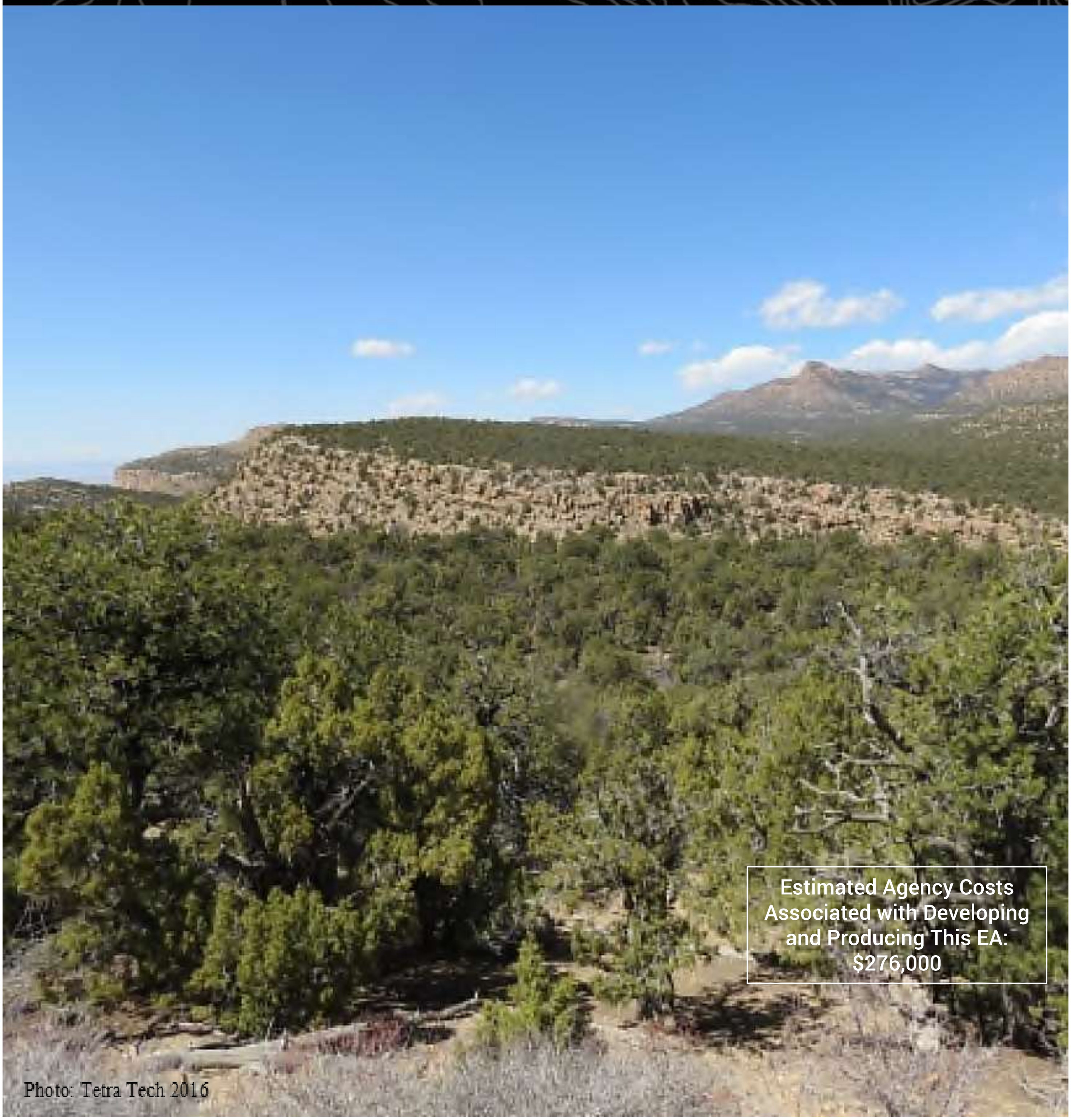
U.S. Department of the Interior
Bureau of Land Management

U.S. Department of the Interior
Office of Surface Mining
Reclamation and Enforcement

Lila Canyon Mine Lease Modifications Environmental Assessment
Emery County, Utah
DOI-BLM-UT-G020-2018-0039-EA

January 2021



Estimated Agency Costs Associated with Developing and Producing This EA: $276,000

Photo: Tetra Tech 2016

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LILA CANYON MINE LEASE MODIFICATIONS
ENVIRONMENTAL ASSESSMENT
EMERY COUNTY, UTAH

Prepared for

U.S. Department of the Interior
Bureau of Land Management
Price Field Office
125 South 600 West
Price, Utah 84501
(435) 636-3600

and

U.S. Department of the Interior
Office of Surface Mining Reclamation and Enforcement
(Cooperating Agency)
1999 Broadway, Suite 3320
Denver, Colorado 80202-3050
(303) 293-5088

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ABBREVIATIONS

μg/m^3: micrograms per cubic meter

Act: John D. Dingell, Jr. Conservation, Management, and Recreation Act

AERMOD: American Meteorological Society/Environmental Protection Agency Regulatory Model

APD: application for permit to drill

ASLM: Assistant Secretary of Land and Minerals Management

AQRV: air quality–related value

BBL: barrels

BLM: Bureau of Land Management

CAA: Clean Air Act

CEQ: Council on Environmental Quality

CFR: Code of Federal Regulations

cfs: cubic feet per second

CH_4: methane

CHIA: Cumulative Hydrologic Impact Assessment

CIA: cumulative impact area

CM: continuous miners

CO: carbon monoxide

CO_2: carbon dioxide

CO_2e: carbon dioxide equivalent

DAT: Deposition Analysis Thresholds

DAQ: Utah Division of Air Quality

DOI: U.S. Department of the Interior

DOGM: Utah Division of Oil, Gas and Mining

EA: environmental assessment

EIS: environmental impact statement

EPA: U.S. Environmental Protection Agency

°F: degrees Fahrenheit

FLPMA: Federal Land Policy and Management Act

FONSI: Finding of No Significant Impact

GHG: greenhouse gas

gpm: gallon per minute

GWP: global warming potential

H_2SO_4: sulfuric acid mist

H6H: 6th-highest daily maximum

H8H: 8th-highest daily maximum

HAP: hazardous air pollutant

HI: Hazard Index

HQ: Hazard Quotient

ID: interdisciplinary

km: kilometers

LBA: lease by application

LMA: lease modification application

MEI: most likely exposure (MLE)

MERP: Modeled Emission Rates for Precursors

mg/L: milligrams per liter

MLA: Mineral Leasing Act

MLE: most likely exposure

MMT: million metric tons

MRP: mining and reclamation plan

MSHA: Mine Safety and Health Administration

N_2O: nitrous oxide

NAAQS: National Ambient Air Quality Standards

NEPA: National Environmental Policy Act

NESHAPs: National Emissions Standards for Hazardous Air Pollutants

NO_x: nitrogen oxides

NO_2: nitrogen dioxide

NSPS: New Source Performance Standards

ONRR: Office of Natural Resources Revenue

OSMRE: Office of Surface Mining Reclamation and Enforcement

PAP: permit application package

PFO: Price Field Office

PM: particulate matter

ppb: parts per billion

ppm: parts per million

PSD: Prevention of Significant Deterioration

RCP: representative concentration pathways

RCRA: Resource Conservation and Recovery Act

RfC: Reference Concentrations

REL: Reference Exposure Levels

RMP: resource management plan

R2P2: resource recovery and protection plan

SCC: Social Cost of Carbon

SCT: Savage Coal Terminal

SITLA: School and Institutional Trust Lands Administration

SMCRA: Surface Mining Control and Reclamation Act of 1977

SO: Secretarial Order

SO_2: sulfur dioxide

TDS: total dissolved solids

TPY: tons per year

TSL: toxic screening levels

UAC: Utah Administrative Code

UDEQ: Utah Department of Environmental Quality

UDWQ: Utah Division of Water Quality

UDWS: Utah Department of Workforce Services

UEI: UtahAmerican Energy, Inc.

UPDES: Utah Pollutant Discharge Elimination System

U.S.: United States

USGS: U.S. Geological Survey

USC: United States Code

WSA: Wilderness study area

VOC: volatile organic compound

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CHAPTER 1. PURPOSE AND NEED

1.1 Introduction

This environmental assessment (EA) has been prepared to analyze the potential impacts of UtahAmerican Energy, Inc.'s (UEI) proposed modifications to federal coal leases UTU-014218 and UTU-0126947 in Emery County, Utah (Figure 1-1). UEI is the lessee of these federal leases, which are being developed as part of the Lila Canyon Mine (Mine), an underground coal mine approximately 9 miles southeast of East Carbon, Utah. The proposed lease modification areas are composed of surface lands and federal minerals managed by the U.S. Department of the Interior (DOI), Bureau of Land Management (BLM). A small tract of surface land within the proposed lease modification areas is held by the State of Utah. Under federal law, a lease modification is an addition of lands to an existing lease that is limited to no more than 960 acres or limited to the size of the lease, if less than 960 acres, for the term of the lease. Following approval of an application, lease modifications are issued on a non-competitive basis to the lease holder. UEI's application for federal coal lease modifications was received at the BLM Utah State Office on November 10, 2017, and revised on December 13, 2017. The two proposed lease modification areas, if approved, would add collectively 1,272.64 acres to UEI's federal coal leases and would be mined by underground methods (the project).

This EA is a site-specific analysis of potential impacts that could result from the implementation of the Proposed Action or its alternatives. An EA assists the BLM in project planning, ensuring compliance with the National Environmental Policy Act (NEPA), and determining whether any significant impacts could result from the analyzed actions. (*Significance* is defined by Council on Environmental Quality [CEQ] regulations for implementing NEPA and is found in 40 Code of Federal Regulations [CFR] 1508.27). An EA provides evidence for determining whether to prepare a finding of no significant impact (FONSI) or an environmental impact statement (EIS). A FONSI would document the reasons why implementation of the selected alternative would not result in significant environmental impacts beyond those already addressed in the BLM's October 2008 *Price Field Office Record of Decision and Approved Resource Management Plan*, hereinafter referred to as the PFO RMP (BLM 2008). If the agency determines that leasing the proposed Lila Canyon modification areas would result in significant impacts, then an EIS would be prepared for the leasing action. If not, a decision record (DR) may be issued based on the findings and alternatives considered.

1.2 Background

On November 10, 2017, UEI submitted a lease modification application (LMA) to the BLM for the modification of its existing federal coal leases (UTU-014218 and UTU-0126947) in Emery County, Utah. The application was revised to respond to the BLM's decision to amend the legal descriptions of the modified lease tracts to reflect aliquot parts of not less than 10 acres, as defined in 43 CFR 3471.1-1. The revised application was received on December 13, 2017. The application was further revised when it was determined that the acreage limitation for modifying federal coal lease UTU-0126947 (not to exceed 960 acres) had in fact been exceeded by roughly 5 acres. This resulted in the removal of 10 acres from this proposed lease modification on March 8, 2019.

The lease modification areas are contiguous to UEI's existing coal leases and have been determined by the BLM to qualify for consideration under 43 CFR 3432.2(a). Figure 1-2 shows the location of the proposed Lila Canyon lease modification areas in relation to the existing lease areas. UEI currently holds 5,549.01 acres of federal coal contained in six federal leases and 1,280 acres of coal from a Utah School and Institutional Trust Lands Administration (SITLA) lease. The Lila Canyon Mine and Lila Canyon portals are located in T. 16 S., R. 14 E., secs. 10 thru 15 and secs. 22 thru 26, and T. 16 S., R. 15 E., secs. 19 and 30. The Lila Canyon Mine development was approved by the Utah Division of Oil, Gas and Mining (DOGM) in 2007 as an extension to the Horse Canyon Mine. The current DOGM permit area (DOGM Permit # C/007/0013) encompasses 4,663.6 acres. The mining and reclamation plan (MRP) is known as the Horse Canyon MRP in DOGM files. Since 2007, all coal reserves have been accessed through the Lila Canyon portals and UEI would continue to use these portals to access reserves in the proposed lease modification areas. For the remainder of this EA, the Mine is referred to as the Lila Canyon Mine, and the MRP as the Lila Canyon Mine plan.

UEI's purpose in applying for the lease modification areas is to obtain the adjacent coal reserves, thereby 1) satisfying underlying needs of continued coal extraction consistent with applicable state, federal, and local environmental permitting and operational requirements; 2) providing a sufficient return to its investors; and 3) preventing the bypass of valuable federal coal reserves. It should be noted that while the overall resource will increase by approximately 7.2 million tons of recoverable coal reserves, and effectively extend the life of UEI's leases by two to three years, the annual coal production limit will not increase unless UEI applies for and receives a production limit increase from the Utah Division of Air Quality (DAQ).

1.2.1 Current Coal Market

In 2019, U.S. coal production decreased 6.6% from 2018 production levels (U.S. Energy Information Administration 2020). Coal production in the Western region (Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming) decreased 8% from 2018 production levels (U.S. Energy Information Administration 2020). The number of producing mines also decreased to 669 mines from 679 mines in 2018 (U.S. Energy Information Administration 2020). U.S. coal consumption in 2019 declined 14.8% from 2018 consumption levels (U.S. Energy Information Administration 2020). Exports of U.S. produced coal in 2020 decreased 32% from 2019 export levels year to date (U.S. Energy Information Administration 2020).

Most of the coal produced at the Lila Canyon Mine is currently shipped to the Hunter Power Plant in Castle Dale, Utah, and Huntington Power Plant in Huntington, Utah. A portion of the coal produced at the Lila Canyon Mine is also shipped to the Intermountain Power Plant in Delta, Utah. An additional portion of the Lila Canyon Mine coal is sent to other mines in the area for blending purposes to support their contracts. However, market conditions can change, resulting in the coal going to different end users, including the potential for export.

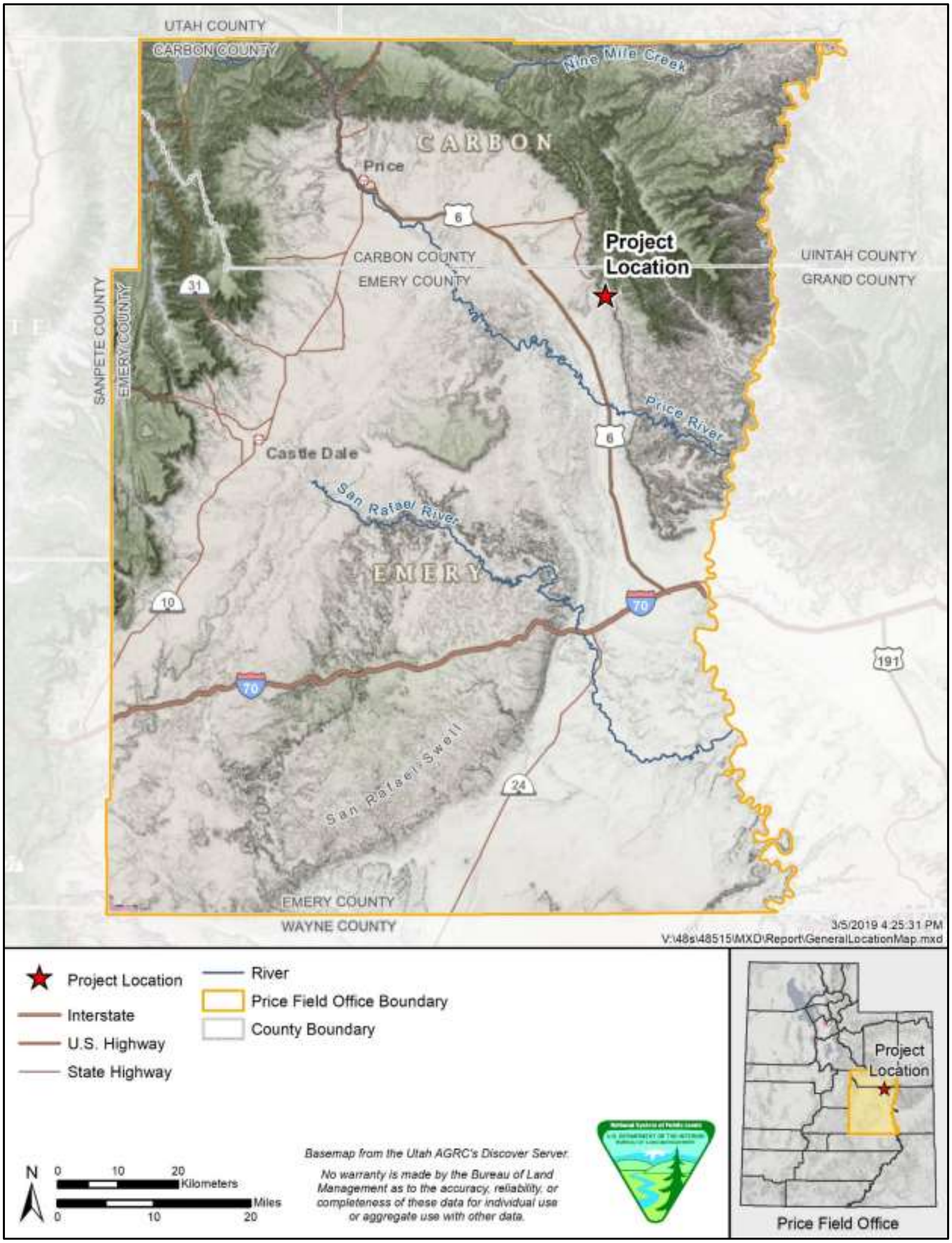

Figure 1-1. General location map.

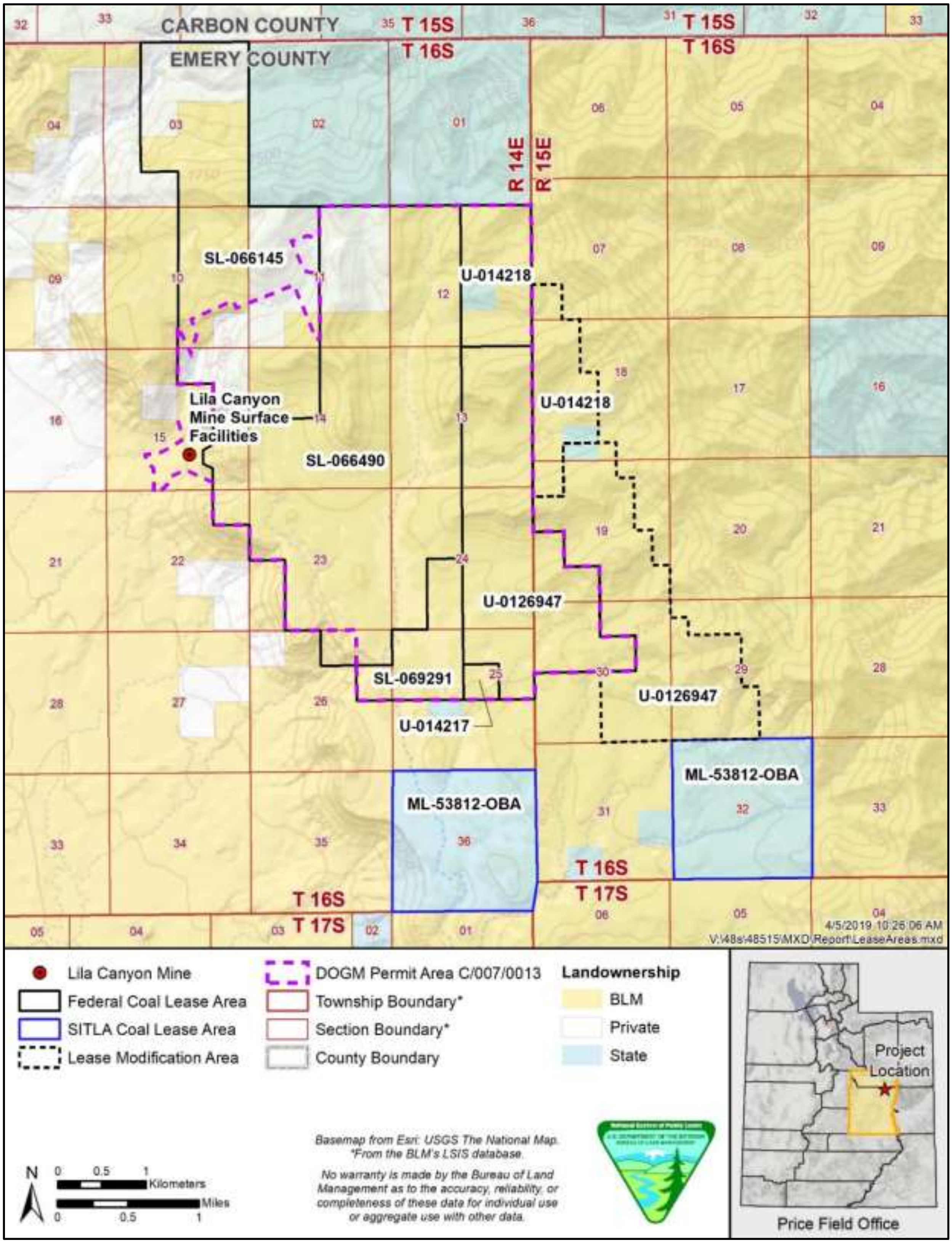

Figure 1-2. Lease modification areas and existing coal leases.

1.3 Purpose and Need for the Action

The purpose of the federal action is to respond to UEI's application to expand two existing leases to add new federal coal reserves on 1,272.64 acres (317.84 acres added to lease UTU-014218 and 954.80 acres added to lease UTU-0126947) of BLM-administered minerals beneath BLM-administered surface lands (other than 39.2 acres where the surface is owned by State of Utah) in Emery County, Utah (see Figure 1-2). The proposed lease modification areas would be added to the Lila Canyon Mine. The need for the action is established by the BLM's responsibility under the Mineral Leasing Act of 1920 (MLA), as amended by the Federal Coal Leasing Amendments Act of 1976, and the Federal Land Policy and Management Act of 1976 (FLPMA), which states that public lands shall be managed in a manner that recognizes the nation's need for domestic sources of minerals (43 United States Code [USC] 1701(a)(12)).

1.4 Decision to be Made

The decision the BLM will make based on this NEPA analysis is whether to lease the federal coal reserves in the proposed modification areas and, if the BLM's decision is to lease, to determine the terms, conditions, and stipulations for issuance of the modified leases. As noted above, lease modifications are issued on a non-competitive basis to the applicant.

1.5 Conformance with BLM Land Use Plan

The PFO RMP was approved in October 2008 and includes goals to provide opportunities for mineral extraction and development to support the need for domestic energy resources (BLM 2008). The PFO RMP allows for such development under mining and mineral leasing laws subject to legal requirements to protect other resource values, including the protection of the long-term health and diversity of public lands. The PFO RMP also includes the objective to "[m]aintain coal leasing, exploration, and development within the planning area while minimizing impacts to other resource values" (BLM 2008:123). The federal coal reserves included in the proposed Lila Canyon lease modification areas are by definition available for leasing and coal mining consideration per 43 CFR 3461.1(a), which states, "federal lands with coal deposits that would be mined by underground mining methods shall not be assessed as unsuitable where there would be no surface coal mining operations." Surface coal mining operations are defined in 43 CFR 3400.0-5 (mm) as "activities conducted on the surface of lands in connection with a surface coal mine or surface operations and surface impacts incident to an underground mine." Decision MLE-2 in the PFO RMP relies upon Map R-24 to show areas available for further coal leasing considerations. Portions of the lease modification areas were not mapped at that time due to RMP Decision MLE-3, which removes wilderness study areas (WSAs) from consideration for coal leasing. At the time the LMA was submitted to BLM, the Turtle Canyon WSA extended into the lease modification areas. With enactment on March 12, 2019, of the John D. Dingell, Jr. Conservation, Management, and Recreation Act (P.L. 116-9) (the Act) (see Section 1.6), there is no longer a Turtle Canyon WSA. The Act designated a new Turtle Canyon Wilderness Area which is not contiguous to and does not encumber the proposed lease modification areas.

The PFO RMP requires modification to remove reference to the Turtle Canyon WSA. However, a plan modification or maintenance action under the PFO RMP is not part of the Proposed

Action for this EA and is not necessary to proceed with the Proposed Action. The PFO RMP Management Decision WSA-7 specifies the following:

> Should any WSA, in whole or in part, be released from wilderness consideration, such released lands will be managed in accordance with the goals, objectives, and management prescriptions established in this RMP, unless otherwise specified by Congress in its releasing legislation. (BLM 2008)

The Act released WSA lands not designated as wilderness under the Act; this release of WSA lands included the portion of the Turtle Canyon WSA that overlapped the proposed lease modifications. The Act specified that WSA lands not designated as wilderness shall be managed in accordance with any applicable management plan adopted under section 202 of FLPMA. The PFO RMP Management Decision MLE-3 specifies that “areas (other than WSAs) will be suitable for leasing.” Therefore, the proposed lease modifications are in conformance with the PFO RMP.

1.6 Relationship to Statutes, Regulations, or Other Plans

UEI’s application for the lease modification areas will be processed and evaluated under the BLM’s statutory mandates and authority governing federal coal leasing and other federal authorities listed below:

- MLA of 1920, as amended by the Federal Coal Leasing Act Amendments of 1976
- Multiple-Use Sustained Yield Act of 1960
- NEPA of 1969, as amended
- FLPMA of 1976 (BLM’s multiple-use mandate)
- Surface Mining Control and Reclamation Act (SMCRA) of 1977
- Mining and Minerals Policy Act of 1970
- Energy Policy Act of 2005

1.6.1 Federal Coal Leasing

The federal coal leasing program also includes a requirement that operators mining federal coal achieve maximum economic recovery (MER) of coal from federal leases. The MER requirement has its legislative origins in the Federal Coal Leasing Amendments Act of 1976, which directs that "the Secretary (of Interior) shall evaluate and compare the effects of recovering coal by deep mining, by surface mining, and by any other method to determine which method or sequence of methods achieves the maximum economic recovery of the coal within the proposed leasing tract ... no mining operating plan shall be approved which is not found to achieve the maximum economic recovery of the coal within the tract." The configuration of the Lila Canyon LMA areas will ensure that MER is achieved.

The coal leasing program was paused in January 2016 under the Jewel Order (Secretarial Order [SO] 3338) until completion of a programmatic environmental impact statement (PEIS); this affected the processing of certain federal leases and restricted the issuance of new leases, with several exemptions and exceptions allowing for such leases to be issued as lease modifications, thereby limiting the number of lease applications impacted (BLM 2019).

On March 28, 2017, Executive Order 13783, the Trump Order, directed agency heads to rescind or revise agency actions viewed as burdensome, with attention placed upon coal and other fossil fuels. On March 29, 2017, then-Secretary Ryan Zinke issued SO 3348, the Zinke Order, which rescinded the Jewell Order and effectively restored the previous status quo.

The BLM, in cooperation with the Office of Surface Mining Reclamation and Enforcement (OSMRE), recently prepared the *Lifting the Pause on the Issuance of New Federal Coal Leases for Thermal (Steam) Coal Environmental Assessment* (DOI-BLM-WO-WO02100-2019-0001-EA). The EA responds to the U.S. District Court of Montana's order issued April 19, 2019, in *Citizens for Clean Energy et al. v. U.S. Department of the Interior et al*., 384 F.Supp.3d 1264, 2019 WL 1756296 (D. Mont.), indicating that the Zinke Order constituted a major federal action triggering NEPA compliance. A public comment period was completed on the EA; public comments were considered, and the EA was finalized in early 2020 with a finding that "lifting the Pause and resuming normal leasing practices created no significant, unstudied impacts" (BLM 2020a). The FONSI was signed February 26, 2020.

The BLM has general responsibility to administer the MLA and regulates coal mining operations consistent with approved resource recovery and protection plans (R2P2s) primarily to ensure that conservation of the coal resource is achieved (43 CFR 3480) while maintaining compliance with other applicable laws and regulations. The R2P2 addresses leased coal reserves, including geologic conditions, coal quality, mining methods and operations (43 CFR 3482). The SMCRA authorizes the OSMRE to oversee state and federal programs that approve mine and reclamation plans and regulate the surface effects of coal mining operations.

1.6.2 Utah Division of Oil, Gas and Mining Permitting

Utah has an approved SMCRA permitting program that is implemented by DOGM. Under Section 503 of SMCRA, DOGM developed a permanent program authorizing it to regulate coal mining operations on non-federal lands in Utah (30 CFR 944, Utah Program, including parts 700 and 800). The Secretary of the Interior approved this program in January 1981. In March 1987, pursuant to Section 523(c) of SMCRA, the governor of Utah entered into a cooperative agreement with the Secretary of the Interior authorizing DOGM to regulate coal mining operations on federal lands in the state of Utah (30 CFR 944.30). The Lila Canyon Mine Permit (DOGM Permit # C/007/0013) is currently located on federal lands and was approved in accordance with the cooperative agreement. If the proposed lease modifications are approved, the operator shall be required to submit a permit application package (PAP) to amend the existing DOGM Permit to add the modified lease areas. DOGM will review the amendment under the State Program and will also submit the permit amendment application to OSMRE. In turn, OSMRE will determine whether the SMCRA permit revision requires a federal Mine Plan approval under the MLA. Under the criteria set forth at 30 CFR 746.18, if the lease modification results in more than a 15% increase in the size of the permit area, a federal Mine Plan approval may be necessary. DOGM coordinates with OSMRE to make this decision. When an MLA Mine Plan modification is required, ASLM approval will be required. OSMRE, BLM, and other federal agencies, as appropriate, review the MLA Mine Plan Modification (provided to them by DOGM) to ensure that it complies with the terms of the coal lease (which are based on the disclosures in this NEPA analysis), the MLA, and other federal laws and their attendant regulations (30 CFR 944.30).

The modified lease areas PAP will be submitted to the Assistant Secretary of Land and Minerals Management (ASLM) if OSMRE decides that this is a significant revision and that a federal mine plan approval via the ASLM is required. OSMRE will recommend approval, conditional approval, or disapproval of the MLA mining plan to the ASLM. OSMRE's recommendation must be based, at a minimum, on the following:

- The PAP, including the R2P2, which must be recommended for approval by the BLM, in order for the ASLM to approve.
- Information prepared in compliance with NEPA.
- Documentation ensuring compliance with the applicable requirements of other federal laws, regulations, and executive orders.
- Comments and recommendations or concurrence of other federal agencies, as applicable, and the public.
- The findings and recommendations of the BLM with respect to the R2P2 and other requirements of the lease and the MLA.
- The findings and recommendations of DOGM with respect to the PAP and the state program.
- The findings and recommendations of OSMRE with respect to the requirements under Chapter VII Subchapter D, 30 CFR 746.13 (a–g).

If a decision is made to issue a modified lease, the lessee must obtain mine plan approval and a permit to conduct coal mining operations, including a detailed MRP, before mining can begin on the modification areas. As discussed above, this MRP and overall PAP would undergo detailed review by state and federal agencies as part of the approval process. The detailed PAP would be required to conform to the stipulations and conditions attached to the lease modification through the land use plan and the decision record that would follow this EA. At a minimum, the lease modifications would contain the stipulations which are contained in the two parent leases. While there could be new stipulations specific to the lease modifications, the parent lease stipulations would apply to each associated lease modification.

The conceptual plans for development described in this EA are not final plans but represent reasonably foreseeable development for use in analyzing the potential environmental consequences of issuing a lease for the modification areas, based on current coal markets and current standard coal mining industry operating practices. If the actual mining proposal is different than what is analyzed in this EA, additional NEPA analysis may be necessary. It should be noted, however, that this EA assumes total extraction of the mineable reserve.

If a proposed modification area is leased to the applicant, the lessee is required to revise its coal mining permit (following the processes outlined above) and obtain mining plan approval from the Assistant Secretary prior to mining the newly leased coal. As a part of that process, a new, detailed plan would be developed to outline how the newly leased lands would be mined and reclaimed. Specific impacts that would occur during the mining and reclamation of the modification area would be addressed in the permit approval process, and specific mitigation measures for anticipated impacts would be described in detail at that time.

DOGM enforces the performance standards and permit requirements for reclamation during a mine's operation and reclamation and has primary authority in environmental emergencies (e.g., accidental spills). OSMRE retains oversight responsibility for this permitting and enforcement.

Where federal surface or coal resources are involved, the BLM has authority in environmental emergency situations if DOGM or OSMRE cannot act before environmental harm and damage occurs.

1.6.3 Mine Safety and Health Administration

The Mine Safety and Health Administration (MSHA) monitors and regulates all safety factors related to coal mining on federal and non-federal lands. In preparing this EA, the BLM has a responsibility to consult with and obtain the comments and assistance of other state and federal agencies that have jurisdiction by law or that have special expertise with respect to potential environmental impacts. Depending on the surface involvement of the federal surface management agency (or agencies), concurrence or consent is required from the federal surface agency (or agencies).

Although the BLM makes the decision on whether to lease the modification areas, DOGM has the authority to approve or reject MRPs for coal mines. Thus, if the modification areas are leased, the lessee would still need a DOGM-approved mine plan before mining could begin. Additionally, MSHA could also require necessary safety measures that could render a coal lease uneconomic. The BLM's primary role is to ensure that maximum economic recovery of the coal is achieved within the requirements of DOGM for protection of resources such as water, wildlife, etc., and within MSHA's safety requirements, and within current, available technology.

1.6.4 Other Planning Documents

Other than the BLM's relevant land use planning decisions in the PFO RMP, no other federal land use plans apply to the alternatives presented in Chapter 2. The State of Utah does not maintain planning documents, nor does it conduct planning processes relating to the alternatives. However, the alternatives would be consistent with the State of Utah Public Lands Policy and Coordination Office's position on 1) uses of public lands for multiple-use, sustained-yield natural resource extraction; 2) support of the specific plans, programs, processes, and policies of state agencies and local governments; and 3) development of the solid mineral resources of the state as an important part of the state economy and of local regions in the state (Utah Code 63-38d-401). The Proposed Action is also consistent with Emery County's *General Plan* in that it addresses the *General Plan*'s support for the development of extraction industries (Emery County 2016). Federal lease rentals and production royalty on the gross proceeds from coal developed in the proposed modification areas would be paid by the mining company to the U.S. Department of Interior, Office of Natural Resources Revenue (ONRR). ONRR then distributes 50% of the federal royalty revenue to the state where the mining occurs. The state shares this revenue with the county or counties in which the mining takes place. Additional overriding royalties on federal coal reserves are limited to 50% of the federal royalty.

1.6.5 John D. Dingell, Jr. Conservation, Management, and Recreation Act

The John D. Dingell, Jr. Conservation, Management, and Recreation Act (S.47) was signed by the President in March 2019 and became P.L. 116-9. Under this law, an area to the east of the proposed lease modification areas, but not adjacent to or overlapping the lease modification areas, was designated as the Turtle Canyon Wilderness Area (Figure 3-1). The Turtle Canyon Wilderness Area will be administered by the Secretary in accordance with the Wilderness Act

(16 USC 1131 et seq.) with exceptions as noted in P.L. 116-9. In addition, the lands that have been adequately studied for wilderness values but not designated as wilderness will be managed in accordance with applicable law and any applicable land management plan. In particular relation to this EA, the latter statement applies to those lands previously considered as part of the Turtle Canyon WSA, which are no longer part of a WSA under this law.

1.7 Identification of Issues

1.7.1 Internal Scoping

The BLM held an introductory interdisciplinary (ID) team meeting in June 2018. It was determined at that time that additional information would be needed to proceed with processing the application. The BLM ID team formulated potential issues associated with the Proposed Action (lease modifications and anticipated full extraction of coal resource) during internal scoping conducted from July through September and completed the ID team checklist (Appendix A) on October 30, 2018, which was updated periodically throughout the EA process.

1.7.2 External Scoping

The BLM listed the Proposed Action on its ePlanning website on May 14, 2018. No public inquiries were received regarding the Proposed Action. The BLM initiated tribal consultation in October 2018 to determine if leasing and mining the proposed lease modification areas would affect cultural resources or Native American religious concerns. A response letter dated October 18, 2018, was received from the Hopi Tribe requesting copies of any cultural resources reports or treatment plans should adverse effects be anticipated as a result of the development of the proposed lease modification areas. There were no other responses.

1.7.3 Issues

The following potential issues were identified during the scoping process:

Air quality and greenhouse gas emissions: How would leasing and mining of the LMA areas contribute to criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gas (GHG) emissions?

Socioeconomics: How would leasing and mining of the LMA areas affect jobs, income, and tax revenues in Emery County, Utah?

Water resources: How would leasing and mining of the LMA areas affect groundwater resources and surface water resources in the analysis area (watershed)?

Geology, minerals, and energy production: How would leasing and mining of the LMA areas affect oil and gas leasing in the areas? How would this potential resource use conflict be managed?

Colorado River Endangered Fish: How would federally listed fish species in the Colorado River system be affected by dry deposition of HAPs due to continued operation of local coal-fired power plants?

CHAPTER 2. DESCRIPTION OF THE ALTERNATIVES

2.1 Introduction

This EA analyzes the potential effects of implementing Alternative A (No Action) and Alternative B (Proposed Action). The No Action Alternative is considered and analyzed to provide a baseline against which to compare the impacts of the Proposed Action. Based upon BLM's internal scoping, no other alternatives were brought forward for detailed analysis. Two alternatives suggested during the public comment period were considered but not carried forward for detailed analysis; they are described below.

If a decision is made to issue a modified lease, the lessee must obtain federal mine plan approval and amend its current DOGM permit to conduct coal mining operations, including a detailed MRP, before mining can begin in the modification areas. As discussed in Chapter 1, this MRP and overall PAP would undergo detailed review by state and federal agencies as part of the approval process. The detailed PAP would be required to conform to the stipulations and conditions attached to the lease modification consistent with the PFO RMP and to conform to the decision that would follow this EA. At a minimum, the lease modifications would contain the stipulations that are contained in the two parent leases. While there could be new stipulations specific to the lease modifications, the parent lease stipulations would apply to each associated lease modification. The parent lease stipulations and the stipulations specific to the lease modifications are provided in Appendix B.

The conceptual plans for development described in this EA are not final plans but represent reasonably foreseeable development for use in analyzing the potential environmental consequences of approving lease modifications for the two tracts based on current coal markets and current standard coal mining industry operating practices. Again, full extraction of the coal resource is anticipated if the Proposed Action is selected.

2.2 Alternatives Development

No alternatives other than the No Action and Proposed Action were developed with respect to the proposed lease modification because there are no unresolved conflicts concerning alternative uses of the available coal resource. Alternatives suggested during the public comment period included an alternative excluding one lease modification to limit the amount of expansion, and a methane reduction alternative to require methane emissions reduction strategies. The No Action and Proposed Action alternatives are described below.

2.3 Alternative A: No Action

Under the No Action Alternative, the BLM would not offer the modification areas for leasing at this time, and the federal coal reserves within the modification areas would not be mined at this time. The choice on the part of the BLM not to lease the modification areas would not preclude leasing and mining of the areas sometime in the future. However, to consider leasing and mining these modification areas in the future, another application would have to be submitted and another NEPA process would need to be completed.

2.4 Alternative B: Proposed Action

Under the Proposed Action, the BLM would offer the Lila Canyon modification areas for lease to UEI, subject to standard and special lease stipulations developed for the tracts (see Appendix B). In the case of federal coal lease modifications, the stipulations attached to the "Parent" lease, at a minimum, always are included as stipulations in the modified area. This does not in any way preclude new stipulations resulting from this action either by the BLM or (not in this case) the surface management agency other than the BLM. The boundaries of the proposed modification areas would be consistent with the location description in Section 2.4.1. The BLM estimates that there are approximately 7.2 million tons of salable coal in these two areas, which are projected to extend the life of the Lila Canyon Mine by approximately two to three years.

Under the Proposed Action, all coal would be mined using underground methods from the existing Lila Canyon Mine as described in Section 2.4.2. UEI would develop these coal reserves by adding, or extending, up to five longwall panels to its mining plan. The location of these reserves, immediately adjacent to the existing Lila Canyon Mine, makes it virtually impossible, physically, that any future mine in this part of the Book Cliffs Coal Field could attempt to access these coal reserves. Given the depth of cover (2,500 to 3,000 feet) and adverse geological conditions (faulting, etc.) in the proposed modification areas, the possibility of mining into these areas from *any* other direction would be too difficult. The only possible scenario, if BLM decides to offer the Williams Draw Lease by Application (LBA) at a competitive lease sale, would be if another mining company besides UEI were to acquire the Williams Draw Federal Coal LBA, start a new mine with all new surface facilities and portal access, and then ultimately access the proposed lease modification areas from the south rather than from the west (Lila Canyon Mine). Because that hypothetical action would also require all new NEPA and all new MRP/PAP analysis, the timing and cost of the activity would render it unfeasible.

2.4.1 Location and Overview

The two Lila Canyon proposed lease modification areas are located in the Book Cliffs coal field in Emery County, Utah, closest to the towns of East Carbon (aka Dragerton) and Sunnyside (see Figure 1-2). From the Lila Canyon Mine portal site, East Carbon, Utah, is roughly 10 miles north- northwest; Green River, Utah, is 32 miles south-southeast; and the Emery County seat of Castle Dale, Utah, is 40 miles west-southwest, across the Castle Valley. The Carbon County seat of Price, Utah, is 25 miles directly west-northwest. The closest coal-loading terminal (unit-train) is the Savage Brothers–owned Savage Coal Terminal (SCT) between Wellington and Price, Utah, on the mainline of the Union Pacific Railroad. The haulage distance to the SCT from the Lila Canyon Mine is approximately 32 miles, and it is another 12 miles to the Wildcat Unit-Train Loadout, located on the Utah Railway near Helper, Utah. For the most part, the Lila Canyon Mine coal is shipped through the SCT, where there is also a heavy media wash plant facility. The lease modification areas encompass 1,233.44 acres of BLM-administered land and 39.2 acres State of Utah-administered land. The total 1,272.64 acres overlay federal (BLM) mineral estate. The two delineated modification areas are contiguous to two of UEI's existing federal coal leases, are contiguous to each other (north to south), and are as described below.

If added to federal lease UTU-014218

- Township 16 South, Range 15 East, Salt Lake Base and Meridian, Utah
  - Section 7: lot 4
  - Section 18: lots 1–4, W1/2 NE1/4 NW1/4, W1/2SE1/2NW1/4, SE1/4SE1/4NW1/4, NE1/4SW1/4, N1/2SE1/4SW1/4
  - Section 19: lot 1

  Total area added to lease UTU-014218: 317.84 acres

If added to federal lease UTU-0126947

- Township 16 South, Range 15 East, Salt Lake Base and Meridian, Utah
  - Section 18: S1/2SE1/4SW1/4, SW1/4SW/4SE1/4
  - Section 19: lot 2, W1/2NW1/4NE1/4, SE1/4NW1/4NE1/4, SW1/4NE1/4, E1/2NW1/4, W1/2SE1/4, SE1/4SE1/4, W1/2NE1/4SE1/4, NE1/4SW1/4
  - Section 29: S1/2NW1/4, SW1/4, W1/2SW1/4SE1/4, SW1/4NW1/4SE1/4, SW1/4NW1/4NW1/4
  - Section 30: SE1/4, N1/2NE1/4, SE1/4NE1/4

  Total area added to lease UTU-0126947: 954.80 acres

In the Lila Canyon area, there are primarily two coal seams located in the Blackhawk Formation: the Upper Sunnyside and the Lower Sunnyside. The two seams have merged in some places within the Lila Canyon holdings but in most areas are separate. Where separate, only one split is mineable due to the thin separation between the two splits; the separation averages 0 to 30 feet. The Upper Sunnyside seam averages 12.4 feet thick according to estimates in the Lila Canyon Mine R2P2 and in the MRP. The Lower Sunnyside seam is much thinner (0 to 5.7 feet) (BLM 2000). Therefore, the Upper Sunnyside is the seam of interest on this property. The seam is considered to be moderately gassy (i.e., methane) and is excellent quality, at 8% ash, 0.8% sulfur, and in excess of 12,000 British thermal units per pound, as-mined.

If mining occurs as proposed, based on UEI's plans, it is expected that UEI would use existing surface facilities currently included in its DOGM-approved mine plan for the Lila Canyon Mine (C/007/0013), with no additional surface disturbance (see Figure 1-2).

2.4.2 Conceptual Mine Plan

If the modified leases are issued to UEI, the conceptual mine plan would use the same mine facilities and the same or similar mining methods, reclamation, water requirements, and other mining activities/requirements, as described in the mine plan for the existing Lila Canyon Mine. Surface-support facilities that would be used in conjunction with the proposed operations on the modification areas would consist of those for the most part already in place and in use for the Lila Canyon Mine area. No new surface facilities would be constructed.

The conceptual mining plans described for the lease modification areas are based on the Lila Canyon Mine plan and other common coal mining practices; these are not final plans but represent reasonably foreseeable development for use in analyzing the potential environmental consequences of modifying leases to develop the projected recoverable coal tonnage.

The BLM would require the Mine to employ measures that will minimize exposure of the public to air pollutants exhausting from mine portals/adits. Measures may include the use of fencing or other physical barriers, natural barriers, signage, or other measures that preclude public access to the portals/adits. Persons who require legal or practical access to the air vents, such as Mine employees or business invites and guests of the Mine, are not considered members of the general public and would continue to have access to these areas.

2.4.2.1 Mining Methods and Mine Facilities

Existing surface-support facilities would provide the necessary infrastructure for personnel, equipment, materials and supplies, and handling and loading of coal production. These facilities are located primarily within a BLM right-of-way issued for this purpose and include structures specifically designed to minimize surface disturbances and/or to control or mitigate impacts to other non-coal resources, such as air, surface water, wildlife, and soils.

Surface facilities include the following (Note: some surface facilities are located at the nearby West Ridge Mine [West Ridge] facility [DOGM ACT 007/041]):

- Small administration office (main administration office at West Ridge)
- Bathhouse/lamphouse
- Mine fan
- Shop/warehouse (West Ridge)
- Coal stockpiling facilities
- Coal reclaiming facilities Electrical power/substation
- Water facilities
- Telephone service
- Water tank(s)
- Other structures (i.e., storage sheds, pump house, aboveground storage tanks, powder magazines, rock dust storage tanks, and trash containment structures) (Lila Canyon and West Ridge)

Initial mine development was completed in Lila Canyon in conjunction with prior approvals to access coal reserves and construct the Lila Canyon portals. Because of the stratigraphic location of the Upper Sunnyside coal seam where it meets the surface in Lila Canyon, the seam was accessed by 1,100-foot rock slopes. The main Lila Canyon entries are the primary “Man and Material” mine access and supply routes for the economically minable portions of the coal seam(s). The entries provide ventilation routes for all other underground workings and the principal coal haulage system (conveyer beltlines).

If the modification areas are leased, continuous miners (CM) would be used to support the longwall mining methods for coal extraction. Longwall mining is used where the coal seam is reasonably continuous in order to create large enough blocks to support longwall. Continuous miners first outline a large block of coal to be mined by longwall methods. Figure 2-1 shows a typical longwall mining scenario where CMs have already developed the longwall block with gate-roads on either side. These gates provide worker and material access, airways, and haulage-ways. The following primary equipment is required to support longwall mining operations:

- Longwall mining system (face conveyor, shearer, shields, etc.) (see Figure 2-1)
- Section power center
- Section coal conveyer

- High-pressure hydraulic pumps   Crew vehicle
- Rock dust system (fire protection)
- Miscellaneous support equipment, such as diesel tractors, trailers, battery or diesel supply haulers, etc.

To construct the gate-roads, the CMs cut the coal, and the coal is hauled from the face by electric shuttle cars and dumped into the feeder-breaker, which crushes large blocks and ratio-feeds the coal to the conveyor belts. Following the CM's 10-to-20-foot cuts, roof bolters come into the area and provide roof support in a variety of ways, depending on specific conditions. Additional maintenance and support equipment and systems include personnel carriers, supply tractors and trailers, lubrication trailers, rock dust and electrical distribution systems, underground communication systems, water pumps, and mine ventilation.

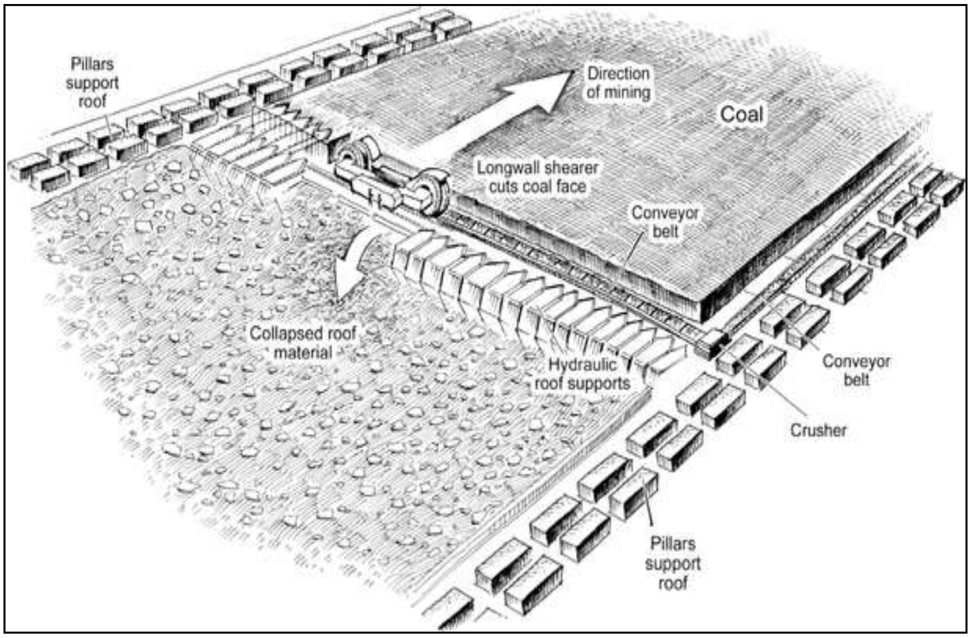

Figure 2-1. Typical longwall mining scenario.
Source: Securities and Exchange Commission (2011).

2.4.2.2 Mine Coal Haulage System

The current underground mining system at Lila Canyon Mine uses a conveyor belt system to transport coal from the underground workings to the surface. The mine coal haulage system consists of several interconnected belt components (feeder breakers, take-ups, drives) to transport coal to the surface. These conveyer belts transport the coal all the way outside to a stockpile. A multi-plate reclaim tunnel is located underneath the coal stockpile for processing and loading trucks.

Two reclaim draw-down ports located at the end of the tunnel allow coal to be reclaimed from the bottom of the pile directly onto a reclaim conveyor located within the tunnel. Each reclaim port contains a pile activator, a hydraulically operated single-bladed shut-off gate, and a discharge chute leading to the reclaim conveyor. Once the coal has been loaded onto the reclaim conveyor, it is transported out from underneath the pile. The reclaim conveyor brings the coal out of the tunnel and transports it to an enclosed crushing/screening building.

From the crusher building, the crushed and screened 2-inch coal is loaded onto a covered loadout conveyor and passed to one of three product piles or transport storage pile. The coal is then transported to an automated truck loadout station. The feed conveyors (i.e., loadout conveyor and reclaim conveyor) start and stop automatically to load the individual truck trailers with a predetermined amount of coal (BLM 2000).

2.4.2.3 Subsidence

No surface expression of subsidence is anticipated above the two proposed lease modifications. The proposed lease modifications cover an area that has very deep cover over the top of the coal seam to be mined. The Lower Sunnyside seam in this area is at least 2,000 feet deep and up to 3,000 feet deep. While there are differing thoughts on calculating maximum subsidence, the BLM uses a calculation that is conservative when compared with other estimates. It says that for every 1 foot in depth of coal mined, there is a possibility for 60 feet (depth) of overburden to shift downward in response. In other words, assuming that the coal seam is 18 feet thick, this would make an upward-caving feature of around 1,100 feet, far beneath the ground surface. This represents a worst-case scenario; although coal seam thickness may reach 18 feet in some areas, longwall equipment used at the Lila Canyon Mine will reach a maximum of 12 feet.

This “worst-case scenario” also assumes longwall panels are mined side-by-side and that the overburden is composed of relatively weak material. In fact, the longwall panels will be mined in a panel-barrier-panel configuration. This means that rather than having two or even three panels adjacent to each other, creating a mined-out area 3,000 feet wide, there would sequentially be a panel-barrier mining sequence - whereas the panel and barrier dimensions would depend upon MSHA requirements. In addition, the overburden at the Lila Canyon Mine contains three massive, very rigid sandstone members totaling approximately 400 feet in thickness.

Three professional mining engineers, from BLM and outside consulting firms, have conducted surveys of the ground cover above the Lila Canyon Mine, as well as above the nearby West Ridge Mine, which had very similar conditions and overburden features. Subsidence was not visible on the surface. The conclusion made from these factors is that surface expression of subsidence should not be evident or measurable.

UEI conducted a color infrared aerial photography study as part of its monitoring commitments under the Lila Canyon Mine DOGM permit approval. The study was conducted to monitor impacts of subsidence on surface vegetation communities. The baseline data was gathered in 2011, and the study was repeated in 2016 per the 5-year interval requirement. No differences were observed between years, suggesting that if subsidence occurred, it has had little impact to the plant and soil communities at the Lila Canyon Mine (UEI 2019a).

2.4.2.4 Post-Mine Reclamation

Under the existing Lila Canyon Mine plan, DOGM would approve, and monitor reclamation of surface facilities and reclamation bond release at the end of the mine life, after the economically recoverable coal reserves have been mined. UEI has posted a bond with DOGM to secure reclamation costs for existing surface facilities at the Lila Canyon Mine. Complete reclamation would include removing all surface facilities, re-grading the surface to achieve approximate original contour, and restoring the area to the approved pre-mining land use. Revegetation would be done with an approved mixture of compatible grasses, forbs, shrubs, and trees. Seed mixes would contain an approved, diverse mixture of species to control erosion and to provide forage for wildlife species. No surface disturbance is planned in the lease modification areas and, thus, no surface reclamation would be required.[1]

2.4.2.5 Water Requirements

- Water usage, based on 1 million tons of coal per year production, would be:
  - Bath house/office (culinary water): 1,260,000 gallons per year
  - Mining: 4,500,000 gallons per year
  - Fan evaporation: 1,183,000 gallons per year

  Total: 6,943,000 gallons per year (BLM 2000)

As coal production increases to 2 million tons per year (TPY), the water used would increase to approximately 11,443,885 gallons per year. Water usage would increase to approximately 15,943,887 gallons per year at 3 million tons of coal annually before peaking at approximately 20,443,888 gallons per year at 4 million tons of coal at full production. Water use requirements are not a linear function of production; culinary use remains fairly constant even if production dips or increases. Potable water is purchased offsite and hauled to the bath house facilities while underground mine water is generally adequate to be used and recycled for underground dust control and fire suppression. (MSHA requirements). UEI has a State of Utah Department of Environmental Quality discharge permit (Utah Pollutant Discharge Elimination System [UPDES] General Permit for Coal Mine Operations) should the mine produce more water from the underground mining process than can be used for the MSHA requirements.

2.4.2.6 Electrical Power Supply

Electrical power for the Lila Canyon proposed lease modification areas development and mining activities would come from an existing 46-kilovolt (kV) overhead power line that terminates at a substation at the existing Lila Canyon Mine. Power would be taken underground, working at 12.5 kV, where section transformers convert the power to equipment-friendly 1,000, 440 and 220 volts.

2.4.2.7 Underground Development Rock

Mine development, ongoing mining production operations, and ancillary operations such as development of overcasts for mine ventilation and coal haulage would result in the production of underground development rock, including carbonaceous shale, weathered coal, floor clay, some sandstone, and parting materials. Where it is operationally feasible to separate these materials from the coal during development and mining, the underground development rock would be removed and handled separately from the coal and placed underground in permanent storage. Where separation is not feasible, underground development rock would be handled with the coal, removed in the surface facilities, separated from the coal product (becoming coal processing waste), and temporarily stockpiled. Stockpiled underground development rock could be sold as a low-quality coal product or deposited in approved facilities, as permitted by DOGM. Most commonly at Lila Canyon and other mines, waste rock is simply placed permanently in underground storage.

[1] DOGM does not simply observe reclamation and move on. The company's reclamation bond cannot be released without achieving reclamation success, and it is then only released in phases for certain accomplishments. For instance, after achieving approximate original contour, Phase I can be released. For achieving good sediment control, Phase II can be released, but the final release (Phase III) will not occur until a minimum of 10 years has passed to ensure successful revegetation.

Generally, the same mining equipment and haulage systems used for coal production would be used to remove and handle underground development rock. However, specialized rock mining and handling equipment could be used.

2.4.2.8 Hazardous Materials and Hazardous and Solid Waste

Potentially hazardous materials used or produced under the current Lila Canyon Mine plan may include fuels (e.g., gasoline and diesel fuel), coolants/antifreezes, lubricants (e.g., grease and motor oil), paints, solvents, resin cartridges, shop rags, lubricant containers, welding rod ends, metal shavings, worn tires, packing material, used filters, and office and food wastes. These are all identified as solid wastes under the Resource Conservation and Recovery Act (RCRA)(42 USC 6901 et seq.). No RCRA chemicals or wastes in excess of regulated amounts would be stored on-site. All wastes would be disposed of in a proper manner as prescribed by law. It should also be noted that under U.S. Environmental Protection Agency (EPA) regulations (40 CFR 372), all coal mining companies are required to maintain a toxic release inventory and produce the documentation of “No Spills” or “Minor Spills” with volume and threshold information for each spill, when requested by EPA.

Most maintenance and major oil changes for the diesel mobile equipment (if any) would take place inside the surface shops. Used oil would be contained and disposed of or recycled in accordance with guidelines administered by the Utah Department of Environmental Quality’s Division of Solid and Hazardous Waste. All fuel storage facilities and equipment would be constructed and operated in accordance with all applicable state and federal regulations, including a toxic release inventory.

All solid and liquid wastes would be contained, stored, and disposed of in accordance with applicable local, state, and federal rules and regulations. Specific containment, storage, and disposal techniques would depend on the type and quantity of waste according to applicable rules and regulations. Typically, non-hazardous solid and liquid waste would be contained on-site in dumpsters and transported periodically to a landfill. Some used equipment could be left in place underground after oils and hazardous materials have been removed and only when approval is received from DOGM and BLM.

Any hazardous solid or liquid wastes would typically be separated and stored in appropriately labeled (according to type of waste) barrels that meet the requirements in the RCRA. Barrels would typically be stored temporarily under cover before being hauled to a hazardous waste disposal facility. A spill prevention plan and other plans are currently in place at the Lila Canyon Mine.

In 2015, the Mine constructed a package plant for treatment of biosolids and constructed a new bath house. The Mine obtained a UPDES Minor Industrial Permit (No. UT0026018) for collection and treatment of wastes transported through a sewer system. Discharge of the treated wastewater is from the package plant to a drainage ditch to Lila Canyon Wash.

2.4.2.9 Normal Operating Hours

As with the current production, it is anticipated that production from the Lila Canyon proposed lease modification areas could occur 24 hours per day, 7 days per week. Most commonly, however, production takes place 16 hours per day and maintenance the other 8 hours per day. In order to maintain cost effective operations, overtime is kept to a minimum.

2.4.2.10 Signage

Required signs and markers in compliance with the applicable regulatory provisions of Utah Administrative Code R645-301-521.200 and MSHA are in place at the existing Lila Canyon Mine. All required signs and markers would be maintained or replaced during the period of active operations, site reclamation, and until final bond release is approved for all areas within the permit boundaries.

2.4.2.11 Estimated Employment Requirements

Leasing the Lila Canyon proposed modification tracts would extend the life of the Mine, but neither the workforce of approximately 238 nor the annual production, which “shall not exceed 4.5 million tons per rolling 12-month period” (DAQ 2013), would be expected to increase.

2.4.2.12 Traffic Estimates

Coal from the proposed modification areas would be transported using existing haul roads to reach U.S. Highway 191/6, and then transported to an existing loadout site on Ridge Road near Wellington, Utah. At a coal production level of 4.5 million TPY, haul trucks (at full capacity of 46 tons) at the Lila Canyon Mine would make approximately 268 round trips per day from the mine to the loadout. The distance between the Mine and the loadout is approximately 32 miles (64 miles round trip). There are also approximately 88 round trips per day made by personal and delivery vehicles to the Lila Canyon Mine (BLM 2000).

CHAPTER 3. AFFECTED ENVIRONMENT AND ENVIRONMENTAL CONSEQUENCES

3.1 Introduction

This chapter presents the existing environment and the environmental consequences on resources that could be affected by the Proposed Action or No Action alternatives. Environmental data collected on the proposed lease modifications were used to describe the affected environment and to evaluate potential environmental impacts. The analysis is intended to allow comparison of alternatives and to provide a method to determine whether activities proposed would be expected to comply with applicable federal, state, and local regulations.

The analysis of impacts is based on the scope of the proposal, which includes about two to three years of underground mining for a total of 7.2 million tons of coal (in the lease modification areas) and aboveground processing and shipping operations at a currently operating facility. No additional surface disturbance would be required to conduct activities and recover the coal.

The impacts from construction of facilities, utilities, transportation routes, and mining and hauling operations at the Lila Canyon Mine are described in the Lila Canyon Project EA (BLM 2000). The air quality assessment and cumulative emissions assessment for the PFO are summarized in the *Utah Bureau of Land Management Air Resource Management Strategy 2020 Monitoring Report* (BLM 2020b).

3.1.1 Setting

The lease modification areas are east of and adjacent to currently developed federal coal leases at the Lila Canyon Mine in Emery County, Utah, located in the Book Cliffs region of the Colorado Plateau Physiographic Province of east-central Utah. This area is approximately 120 miles southeast of Salt Lake City, Utah, and approximately 10 miles south of East Carbon, Utah.

Elevations in the lease modification areas range from approximately 8,113 feet above mean sea level (amsl) near the northern portion of lease modification area U-014218 to 6,800 feet amsl at the southern boundary of lease modification area U-0126947 (see Figure 1-2). Characteristic vegetation includes Douglas fir (*Pseudotsuga menziesii*) at the highest elevations, pinyon-juniper forests over most of the bench areas, and a mixture of shrubs and grasses in the low areas (BLM 2000).

Climate data from the Sunnyside, Utah, National Oceanic and Atmospheric (NOAA) weather station (428474) is provided in the Lila Canyon Mine MRP as being generally representative of conditions at the Lila Canyon Mine (Cirrus and Petersen 2017). The average annual mean monthly temperature at Sunnyside, Utah, is 47.55 degrees Fahrenheit (°F), with an annual high temperature of 59.6 °F and an annual low temperature of 35.5°F (U.S. Climate Data 2019).

3.1.2 Past, Present, and Reasonably Foreseeable Future Actions

Past and present actions near the LMA areas are mainly underground mining and underground mining–related operations, which include coal combustion at local coal-fired power plants (Appendix C). Energy sector production between 2015 and 2019 in Utah, the region, and the nation is described in Appendix D. Past and present actions may influence the environmental setting for analysis of site-specific effects of the Proposed Action. Reasonably foreseeable future actions are actively proposed events that may affect the same resource(s) during the timeline of the Proposed Action.

3.1.2.1 Past and Present Actions

Table C-1 (Appendix C) lists the past and present actions in the resource-specific analysis areas that are considered in the analysis of cumulative effects. Appendix D describes state, regional, and national energy sector production and emissions trends.

3.1.2.2 Reasonably Foreseeable Future Actions

Reasonably foreseeable future actions in the resource analysis areas defined in this chapter are identified below and listed in Table C-2 (Appendix C). None of the past, present, or reasonably foreseeable future actions described in this section are considered connected actions to the Proposed Action analyzed in this EA (see Appendix C). Reasonably foreseeable future actions in the vicinity of the lease modification areas are identified below. Energy sector production trends for the region and nation are described in Appendix D. No new coal-fired power plants are proposed or anticipated for Utah or the region. Most of Utah's electric generating capacity added since 2016 is powered by solar energy (EIA 2020).

<u>SITLA Coal Lease</u>: UEI was granted a lease in October 2018 by the State of Utah through SITLA for the exclusive right to explore for, drill for, mine, remove, transport, convey, cross-haul, commingle, and sell the coal contained within the boundaries of T. 16 S., R. 14 E., sec. 36 and T. 16 S., R. 15 E., sec. 32 (see Figure 1-2) in Emery County. The SITLA lease has an initial 10-year term. It is reasonably foreseeable that UEI will include the extraction of the coal in these sections in future plans.

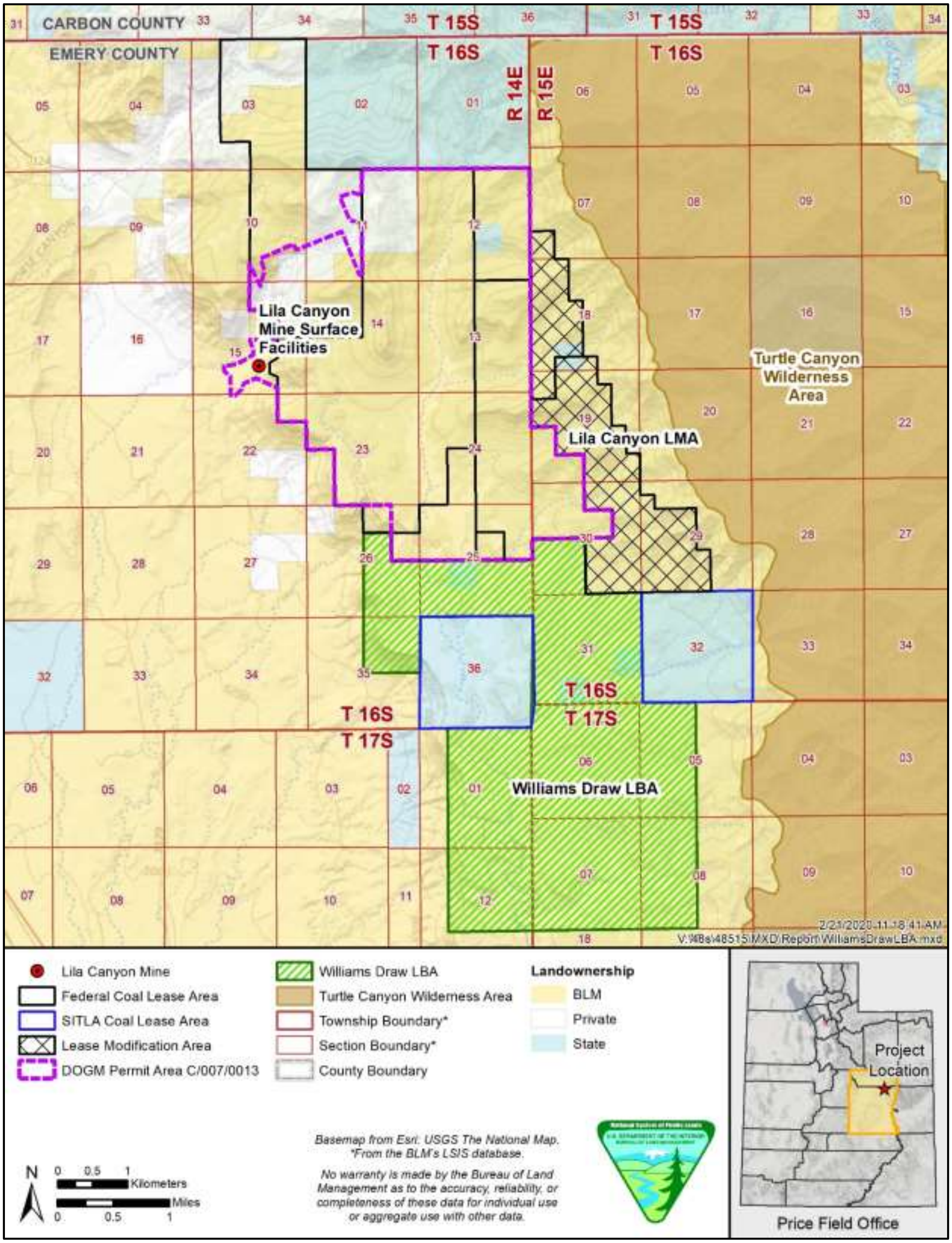

Figure 3-1. Nearby wilderness and proposed LBA.

Williams Draw LBA: UEI submitted a coal LBA for approximately 4,232 acres in the Williams Draw area, south of current UEI reserves (see Figure 3-1). The LBA delineation and recoverable reserves have been determined by the BLM. The BLM is currently assessing whether to lease the LBA coal. If the BLM decides to offer the Williams Draw LBA at a competitive lease sale, and if the LBA is leased by UEI, then mining in the leased area may occur while the Lila Canyon Mine reserves are being mined or after the Lila Canyon Mine reserves are exhausted. Under P.L 116-9, the BLM will no longer manage the land surface, or the coal described in the Williams Draw LBA; both will be controlled by SITLA. It should be noted that depending on the timing of exchange parcels between BLM and SITLA, that BLM may decide to conduct a competitive sale and issue the Williams Draw lease to the successful bidder prior to it being turned over to SITLA. In any case, the mining of the resource is the subject here.

Walker Flat LBA: Bronco submitted a coal LBA in March 2018 for 2,956 acres in the Walker Flat area of Emery County, Utah, located approximately 62 miles or 100 kilometers (km) southwest of the Lila Canyon Mine. In August of 2020, Bronco modified the application to reduce the LBA acreage from 2,956 to 1,042. If this area is leased and developed, then mining in the Walker Flat area may occur while the Lila Canyon Mine and Williams Draw LBA (if offered and leased) are being mined. The BLM is preparing a draft EA to describe the potential environmental impacts of leasing the Walker Flat coal tract. Mining the Walker Flat LBA would extend the life of the Bronco Utah Mine, which produced approximately 694,000 tons of coal in calendar year 2019. Depending upon demand and regulatory agencies' ability to process its request, Bronco could begin mining on Walker Flat within the next 3 years. The Bronco Utah Mine is permitted to produce up to 2 million tons of coal per year (rolling 12-month period); additional permitting would be required to increase production above this amount.

Little Eccles Coal LBA and LMA: Canyon Fuel Company, LLC provided applications to the BLM Utah State Office to modify coal lease UTU-77114 in Sanpete County and to lease the Little Eccles Tract in Emery County located near the Skyline Mine. Surface ownership is managed by the U.S. Forest Service. The BLM, U.S. Forest Service, and OSMRE will prepare an EIS to inform decision-making for these applications.

Uinta Basin Railway: The Utah Surface Transportation Board is currently analyzing a request filed by the Seven County Infrastructure Coalition for authority to construct and operate an approximately 85-mile common-carrier rail line connecting two termini in the Uinta Basin near South Myton Bench, Utah, and Leland Bench, Utah, to the national rail network via an existing rail line owned by Union Pacific Railway Company near Kyune, Utah. The proposed rail line would be used to transport crude oil, fracturing sand, machinery, and mineral and agricultural products and commodities. Three alternative routes are being considered in an EIS. All of these routes dip into northern Carbon County, Utah, for an approximate 5-mile stretch north of Helper. The BLM is participating as a cooperating agency in the EIS process. The three build alternatives may cross BLM-administered lands, and if so, a rail right-of-way would be needed.

BLM Quarterly Oil and Gas Lease Sales: Leasing of public lands for oil and gas exploration and production is required by the Mineral Leasing Act of 1920, as amended, and the BLM's current policy is to apply the least restrictive management constraints to the principal uses of the public lands necessary to achieve resource goals and objectives. Parcels to be offered would be leased subject to stipulations prescribed by the RMP. Before any surface-disturbing operations may be authorized, an additional site-specific analysis would be completed through the NEPA process. Further mitigation (if warranted and consistent with standard lease terms, notices, and stipulations) to reduce impacts to the environment and other uses of the public lands could be required through the application for permit to drill (APD) or right-of-way processes.

December 2017 Competitive Oil and Gas Lease Sale: The BLM offered 74 parcels, totaling approximately 94,000 acres in Duchesne, Uintah, and Emery Counties, at its December quarterly oil and gas lease sale. The impacts of offering 15 of the 74 parcels were analyzed in the EA prepared by the PFO. The BLM held the lease sale online at www.energynet.com on December 12, 2017. None of the 15 parcels offered in the PFO received bids at the competitive sale. Three parcels were sold non-competitively after that sale.

3.2 Air Quality and Greenhouse Gas Emissions

In accordance with CEQ regulation 40 CFR 1502.21, the air quality analysis in this EA incorporates by reference the air technical report (SWCA 2019). This document is incorporated by reference because the Williams Draw LBA is located adjacent to the Lila Canyon Mine (to the south) and, like the proposed lease modification areas, would most likely use the existing Lila Canyon Mine surface facilities and coal movement operations if offered for lease and if UEI is the successful bidder for the Williams Draw LBA. Production from the Williams Draw LBA is anticipated to be 3.0 to 3.5 million tons per year, extending the life of Lila Canyon Mine by approximately 10 to 15 years. There is an estimated 32 million tons of recoverable coal in the Williams Draw tract, with another 4 to 5 million tons on a SITLA coal lease (SWCA 2019). The air technical report includes an emission inventory for the pending Williams Draw LBA, which is generally based on production limits established in the DAQ approval order for Lila Canyon Mine. The Lila Canyon Mine production limit is 4.5 million tons per year (unless the DAQ approves an increase in production), whether that coal is mined from existing leases, lease modifications, or newly-approved leases (such as an LBA). The impact analysis modeling was based on the DAQ approval order limit of 4.5 million TPY, which is higher than what is anticipated under the Proposed Action. The air technical report also includes a near-field modeling analysis.

Because the same facility production limits would remain in effect for the processing of coal from the proposed lease modification areas, the Williams Draw emissions and modeling data can be used as a proxy analysis for the proposed LMAs.

The analysis area for air quality comprises the 50-km near-field modeling analysis area delineated in the *Williams Draw Coal NEPA Analysis: Air Technical Report* (air technical report) (SWCA 2019). This analysis area was selected because the Williams Draw coal tract is located adjacent to the Lila Canyon Mine (to the south) and its impacts would be similar to those from development of the proposed lease modification areas. Because GHGs circulate freely throughout the atmosphere and continue to build up over time, the cumulative analysis for GHGs and climate change includes regional (Utah, Wyoming, New Mexico, and Colorado) and national data.

3.2.1 Affected Environment

3.2.1.1 Regulatory Requirements

Mining operations, coal transportation, and other elements of the Proposed Action would emit air pollutants regulated under the Clean Air Act (CAA). CAA provisions that are relevant to the Proposed Action include the NAAQS, the Prevention of Significant Deterioration (PSD), Class I and Class II areas, Air Quality-Related Values, General Conformity, and New Source Performance Standards (NSPS), Non-Road Engine Tier Standards, and National Emission Standards for Hazardous Air Pollutants (NESHAPs).

National Ambient Air Quality Standards

The EPA has established NAAQS to limit the amount of air pollutant emissions considered harmful to public health and the environment. Primary and secondary standards have been set for six criteria pollutants: carbon monoxide (CO), lead, nitrogen dioxide (NO_2),[2] ozone,[3] sulfur dioxide (SO_2), and particulate matter (PM). The NAAQS are summarized in Table 3-1.

Any state can promulgate ambient air quality standards that are more stringent than those of the national program; however, air quality standards cannot be less stringent. Utah has adopted the federal primary and secondary NAAQS and has not established any state level standards.

The EPA assigns classifications to geographic areas based on monitored NAAQS concentrations. If the air quality in a geographic area meets or is cleaner than the primary and secondary NAAQS for a criteria pollutant, it is called an attainment area (designated unclassifiable / attainment) for that pollutant. If the air quality in a geographic area does not meet the primary and secondary NAAQS for a criteria pollutant, it is called a nonattainment area for that pollutant. A particular geographic region may be designated an attainment area for some pollutants and a nonattainment area for other pollutants. Maintenance areas are previously designated areas for one of the NAAQS that have since met the NAAQS standards. *Unclassifiable* typically refers to an area where there is no monitoring data to verify its attainment status, so the EPA assumes it is in attainment. These are typically rural areas where air quality is generally not an issue. Emery County is in unclassifiable/attainment for all criteria pollutants (SWCA 2019).

Table 3-1. National Ambient Air Quality Standards

Pollutant		Primary or Secondary	Form	Averaging Time	NAAQS
CO		Primary	Not to be exceeded more than once per year	8 hours	9 parts per million (ppm)
				1 hour	35 ppm
Lead		Primary and secondary	Not to be exceeded	Rolling 3-month average	0.15 micrograms per cubic meter ($\mu g/m^3$)
NO_2		Primary	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years	1 hour	100 parts per billion (ppb)
		Primary and secondary	Annual mean	1 year	53 ppb
Ozone		Primary and secondary	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years	8 hours	0.070 ppm
Particulate matter	$PM_{2.5}$*	Primary	Annual mean, averaged over 3 years	1 year	12.0 $\mu g/m^3$
		Secondary	Annual mean, averaged over 3 years	1 year	15.0 $\mu g/m^3$
		Primary and secondary	98th percentile, averaged over 3 years	24 hours	35 $\mu g/m^3$
	PM_{10}*	Primary and secondary	Not to be exceeded more than once per year on average over 3 years	24 hours	150 $\mu g/m^3$
SO_2		Primary	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years	1 hour	75 ppb
		Secondary	Not to be exceeded more than once per year	3 hours	0.5 ppm

Source: EPA (2016a).

* PM_{10} is PM that is 10 micrometers in diameter or less; $PM_{2.5}$ is PM that is 2.5 micrometers in diameter or less.

[2] EPA uses NO_2 as the indicator for the larger group of oxides of nitrogen or NO_x. However, emissions are usually reported as NO_x.

[3] Ozone is not directly emitted into the air but is created by chemical reactions between NO_x and volatile organic compounds in the presence of sunlight.

Other Regulations

<u>Prevention of Significant Deterioration</u>

The PSD is a permitting program for new major sources or major modifications of existing sources of air pollution located in attainment areas. The program applies to new (or modified) major stationary sources in attainment areas; major sources are defined as those sources that emit 100 tons per year or more of any criteria pollutant for specifically listed source categories or that emit 250 tons per year of any criteria pollutant and are not in a specifically listed source category. The Proposed Action would not be in a listed source category and does not qualify as a major PSD source based on the emission inventory in Section 3.2.3.1.

Class I and Class II Areas

Under PSD regulations, the EPA classifies airsheds as Class I, Class II, or Class III. Class I areas are those areas where the most stringent standards for changes to air quality are in effect. These are areas of special national or regional natural, scenic, recreational, or historic value, for which PSD regulations provide special protection. Moderate pollution increases are allowed in Class II areas. In Class III areas, substantial industrial or other growth is allowed, and increases in concentrations up to the NAAQS are considered insignificant. No Class III areas have been designated to date; therefore, all areas not designated as Class I areas are known as Class II areas. If a source is subject to the PSD permitting program, it must perform air quality monitoring and modeling analyses, in addition to installing best-available control technology, performing an additional impacts analysis, and public involvement. A proposed source can demonstrate that it does not cause or contribute to a violation by demonstrating that the ambient air quality impacts resulting from the emissions would be less than the significant impact levels.

In conducting an air quality modeling analysis, PSD increment consumption must also be evaluated for a major source. A PSD increment is the maximum allowable increase in ambient concentrations allowed to occur above a designated baseline concentration; in contrast, the NAAQS establishes maximum total ambient concentrations for air pollutants. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. PSD increments have been established for Class I, II, and III areas.

Based on the modeling protocol, the nearest Class I area to the proposed lease modification areas is Arches National Park, which is approximately 53 miles to the southeast (Figure 3-2). Other nearby Class I areas are Canyonlands National Park (approximately 68 miles south-southeast) and Capitol Reef National Park (approximately 77 miles southwest). Jurassic National Monument, at the site of the Cleveland Lloyd Dinosaur Quarry, a Class II area of interest, is located approximately 19 miles west-southwest of the proposed lease modification areas. Two wilderness areas are also located near the proposed lease modification areas: Turtle Canyon Wilderness (approximately 1.5 miles to the east) and Desolation Canyon Wilderness (approximately 5.2 miles to the east). The Turtle Canyon and Desolation Canyon Wilderness areas are Class II areas under the PSD program.

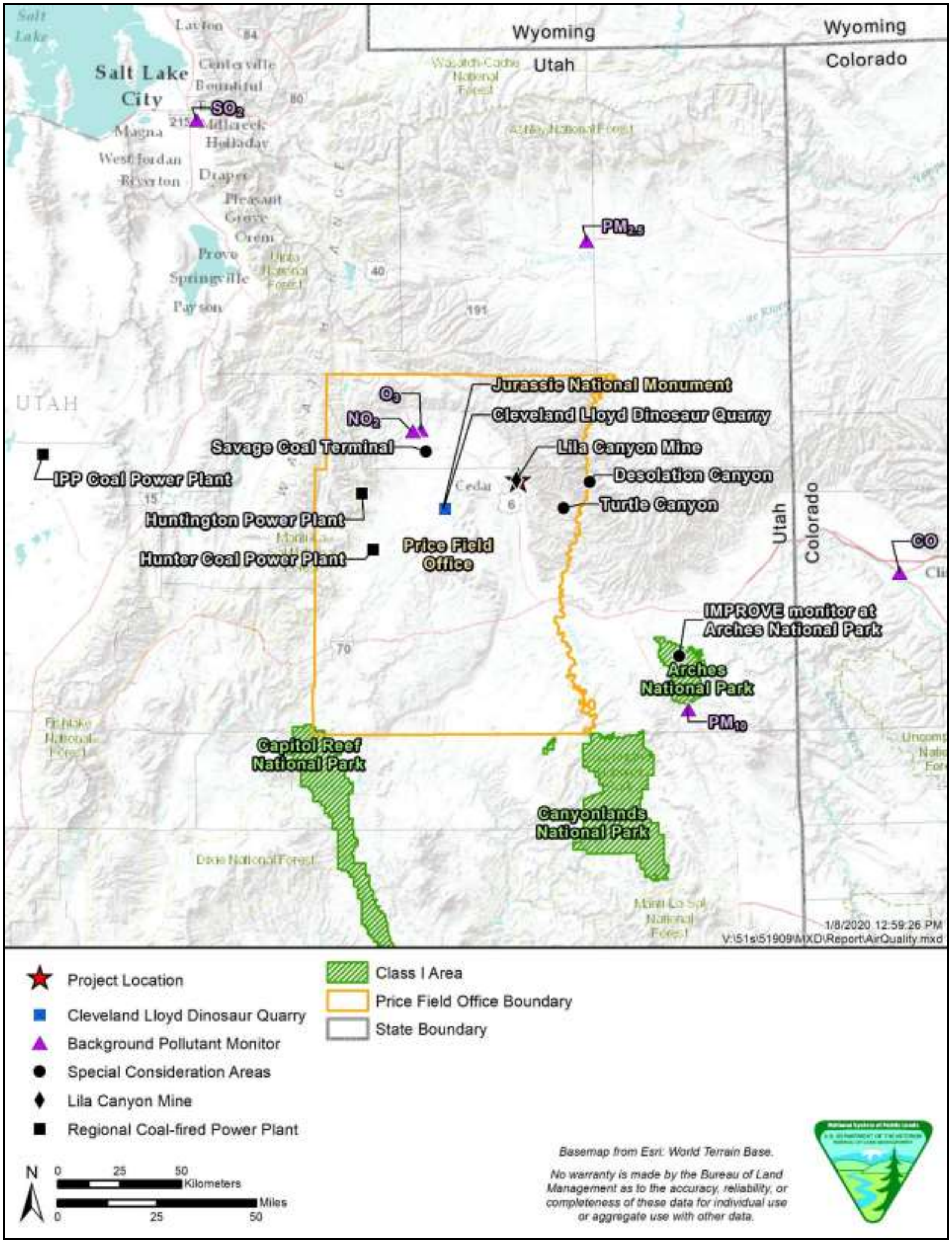

Figure 3-2. Air quality resources.

Air Quality–Related Values

An air quality–related value (AQRV) is defined as a resource "for one or more Federal areas that may be adversely affected by a change in air quality. The resource may include visibility or a specific scenic, cultural, physical, biological, ecological, or recreational resource identified by a federal land manager for a particular area" (U.S. Forest Service et al. 2010). The requirement to assess impacts to AQRVs is established in the PSD rules. The federal land manager for each Class I area has the responsibility to define and protect the AQRVs at such areas and to consider whether new emissions from proposed major facilities (or modifications to major facilities) would have an adverse impact on those values. For example, increased nitrogen or sulfur deposition from new or modified facilities could have a negative impact on AQRVs sensitive to such deposition, including lakes, streams, soils, vegetation, and wildlife.

General Conformity

The General Conformity Rule, established under 40 CFR 51(w) and 40 CFR 93(b), mandates a general conformity analysis for projects that require federal action. It applies to emission units or emission-generating activities resulting from a project that are not already covered by permitting and that are located in a nonattainment area. This regulation ensures that federal actions conform to the State Implementation Plan and state attainment plans. Because Emery County is an unclassifiable/attainment area, the General Conformity Rule does not apply to the LMA areas.

New Source Performance Standards

The EPA has also promulgated technology-based standards for specific sources of air pollution, known as the New Source Performance Standards (NSPS) (40 CFR 60). NSPS Subpart Y, Standards of Performance for Coal Preparation and Processing Plants, applies to the Lila Canyon Mine and affects coal production emission sources. NSPS regulations also apply to the SCT (Subparts A, Dc, and Y). NSPS regulations also require new engines of various horsepower classes to meet increasingly stringent nitrogen oxides (NO_X) and volatile organic compound (VOC) emission standards over the phase-in period of the regulations. In the air technical report emission inventory, NSPS are assumed to apply to all stationary engines (SWCA 2019).

Non-Road Engine Tier Standards

The EPA also sets emissions standards for non-road diesel engines for hydrocarbons (i.e., VOC), NO_X, CO, and PM. The emissions standards are implemented in tiers by year, with different standards and start years for various engine power ratings. The new standards do not apply to existing non-road equipment. Only equipment manufactured after the start date for an engine category (1999–2006, depending on the category) is affected by the rule. Over the life of the reasonably foreseeable development activities, the fleet of non-road equipment is expected to turn over, and higher-emitting engines will be replaced with lower-emitting engines. Non-road fleet turnover is not accounted for in the air technical report emission inventory; therefore, the emissions represent a conservative estimate for this source category.

The EPA engine tier standards do not apply to the underground mining equipment. In accordance with 40 CFR 1039.5(c), engines used in underground mining or in underground mining equipment are regulated by the MSHA in 30 CFR. Specifically, the MSHA standards at 30 CFR 72.500–72.502 establishes exhaust diesel PM emissions for permissible and non-permissible diesel-powered equipment, and 30 CFR 57.5060 establishes limits on miner exposure to diesel particulate matter. In addition to Diesel Particulate Matter standards, the concentration of NO_2 in underground mining environments may not exceed a ceiling value of 5 parts per million (ppm) as established in MSHA standards at 30 CFR 75.322. Furthermore, 30 CFR 70.100 establishes concentration limits for respirable coal mine dust to 1.5 mg/m^3 at underground coal mines. MSHA requires a mine to take corrective action at lower concentration levels, so it is unlikely that these thresholds will be reached.

National Emission Standards for Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of hazardous air pollutants (HAPs); these are known as the National Emissions Standards for Hazardous Air Pollutants (NESHAPs). HAPs (e.g., benzene, perchloroethylene, mercury) are known or suspected to cause cancer or other serious health effects. There are no NESHAP regulations that are applicable specifically to coal mining. Therefore, NESHAPs and maximum achievable control technology regulations do not apply to the Lila Canyon Mine or SCT.

3.2.1.2 State Permitting

Lila Canyon Mine

Stationary pollutant sources at the existing Lila Canyon Mine are regulated by the DAQ and are subject to Utah Administrative Code R307-401-8, which requires an approval order prior to constructing, installing, establishing, operating, or modifying air pollution-producing sources. The existing Lila Canyon Mine operates under Utah approval order number DAQE-AN121850003-13, dated May 10, 2013. The approval order establishes a production limitation of 4.5 million tons of coal per rolling 12-month period. This production limitation applies to the Mine and thus limits coal produced by the Mine in total from its existing, modified, or new leases, should any be obtained. Approved equipment at the Lila Canyon Mine consists of the underground coal mine, an enclosed crusher, a screen, truck loading facility, stacking tube associated with the coal stockpile, underpile reclaim system, rock dust silo, conveyors and mobile equipment, and diesel and gasoline storage tanks. The approval order establishes opacity limitations for particular emission sources such as conveyor transfer points. Opacity monitoring conducted in October 2018 observed no emissions from any of the emission sources (Barr Engineering Co. 2018). Water sprays or chemical dust suppression sprays are required at the enclosed crusher exhaust, at all conveyor transfer points, on unpaved roads and operational areas, and on storage piles to minimize fugitive dust generation.

Savage Coal Terminal

Stationary sources at the existing SCT are authorized by Utah approval order number DAQE-AN117930009-17 (last revised on June 21, 2017). The approval order establishes the following production limits: 9,500,000 tons of coal per rolling 12-month period and 1,000,000 tons of coal screened per rolling 12-month period.

Approved equipment at the SCT consists of coal truck unloading facilities, stacking tubes with associated coal stockpiles, covered radial stackers, a material processing crusher, underpile reclaim systems, an underground reclaim, a wash plant, material handling conveyors, a silo, diesel fuel tanks, antifreeze storage tanks, a fuel dispensing station, oil transloading racks, condensate collectors, vapor capture systems, a natural gas-fired boiler, a diesel generator, and on-site haul roads. The approval order establishes opacity limitations for particular emission sources such as crushers and screens. Water sprays or chemical dust suppression sprays are required at all crushers and screens, on repeatedly disturbed areas, on unpaved roads and operational areas, and on storage piles to minimize fugitive dust generation. The approval order also requires enclosure of each conveyor transfer or drop point, all aboveground conveyors, the reclaim conveyor from the primary coal stockpile to the stacking tube, and the wash plant screens, crushers, and conveyors.

3.2.1.3 Existing Conditions

Climate

The climate in the vicinity of the proposed lease modification areas is discussed in detail in the air technical report and summarized briefly here. Generally, the climate is arid and influenced by both the Sierra Nevada and the Wasatch Mountains. Summers tend to be hot and dry, and winters are usually cold. Temperatures depend on elevation and latitude and can range from an average low of 15°F in January to an average high of 90°F in July (SWCA 2019). Wide ranges in temperature may occur over 24 hours as heat quickly builds during the day and rapidly dissipates at night. The average wind speed in the Lila Canyon Mine area is 7 miles per hour (mph) and it usually comes from the north-northeast. The area has an average annual precipitation of 10 inches, with August and September being the wettest months by average precipitation (SWCA 2019).

Background Air Quality

Background air quality in the Lila Canyon Mine area is provided in the air technical report and summarized briefly here. Background levels of criteria pollutants are provided in Table 3-2. The monitored concentrations in Table 3-2 are generally the averages of three years of data from pollutant monitors closest to the proposed lease modification areas. Monitors and averaging periods were selected by their relative distance to these areas and by recommendation of the DAQ.

Table 3-2. Background Levels of Criteria Pollutants

Pollutant	Monitoring Station ID	City, State	Approximate Distance from Proposed Project (miles)	Averaging Period	Monitored Concentration		
					(ppm)	(ppb)	(μg/m^3)
CO*	08-077-0018	Grand Junction, Colorado	101	1-hour	1.50	–	–
				8-hour	1.30	–	–
NO_2†	49-007-1003	Price, Utah	27	1-hour	–	18.00**	–
				Annual	–	6.40††	–
Ozone‡	49-007-1003	Price, Utah	27	8-hour	0.067	–	–
$PM_{2.5}$§	49-013-0002	Roosevelt, Utah	65	24-hour	–	–	24.00
				Annual	–	–	6.10
PM_{10}¶	49-019-0006	Moab, Utah	73	24-hour	–	–	42.00
SO_2#	49-035-3006	Salt Lake City, Utah	121	1-hour	–	7.00	–
				3-hour	–	6.33	–

Source: SWCA (2019).

ppm = parts per million; ppb = parts per billion; μg/m^3 = micrograms per liter

*Data from Grand Junction-Pitkin monitor for the years 2015–2017.

†Data from monitor on private property for the years 2012–2014.

‡Data from monitor on private property for the years 2015–2017.

§Data from Roosevelt monitor for the years 2015–2017.

¶Data from Moab monitor for the years 2000–2003.

#Data from Hawthorne monitor for the years 2015–2017.

**Design value from AQS, H8H, for the years 2015–2017.

††Two-year average of annual mean; 2015 did not have complete data.

Emission inventories provide a summary of the type and amounts of pollutants emitted on an annual basis from a particular source. Total emissions from the most recent emission inventories for Emery County and Carbon County are summarized in Table 3-3. While the Lila Canyon Mine is in Emery County, it is near the border and close to emission sources in Carbon County. The Hunter and Huntington Power Plants are major emissions sources operating in northwestern Emery County and thus their emissions are included in the emission inventory. There are no major emissions sources within the 50-km (31-mile) near-field study area. The Hunter Power Plant, approximately 37 miles (60 km) west-southwest of the LMA areas, is a Phase II Acid Rain source and is a major source for SO_2, NOx, PM_{10}, CO, VOC, HAP, hydrochloric acid (HCl), and GHG. The Huntington Power Plant, approximately 36.5 miles (59 km) west of the LMA areas, is a Phase II Acid Rain source and is a major source of SO_2, NOx, PM_{10}, CO, HAP, hydrofluoric acid, and HCl emissions. The Hunter and Huntington Power Plants are permitted by DAQ under Title V permits; both plants were originally constructed in the 1970s (see Appendix E). Hunter and Huntington power plants combust approximately 6.4 million tons of coal annually. In 2019, the total reported mercury emissions to the atmosphere from fugitive and stack sources at Hunter and Huntington Power Plants was 5.9 pounds (approximately 0.003 TPY).

Table 3-3. 2014 Total Emission Inventory for Emery County and Carbon County

Pollutant	Emery County Emissions (tons per year)	Carbon County Emissions (tons per year)
CO	17,854	8,045
NO_x	20,397	6,318
PM_{10}	4,891	4,928
$PM_{2.5}$	1,257	866
SO_2	6,427	10,334
Volatile organic compounds	36,111	17,014
Hazardous air pollutants	127	78

Source: DAQ (2014).

Mercury emissions are included in the HAPs category (see Section 3.2.1.1). Mercury emissions are a very small fraction of the total HAPs emissions. In 2017, Carbon County reported 0.00052 TPY of mercury and Emery County reported 0.0028 TPY of mercury (DAQ 2019) (see Appendix E).

Climate Change

Global warming refers to the ongoing rise in global average temperature near the Earth’s surface. It is caused mostly by increasing concentrations of GHGs (primarily carbon dioxide [CO_2], methane [CH_4], nitrous oxide [N_2O], and fluorinated gases) in the atmosphere, and it is changing global climate patterns. Climate change refers to any significant change in the measures of climate (e.g., temperature, precipitation, and wind patterns) lasting for an extended period of time (EPA 2017a). Estimates of GHG emissions are usually reported in terms of carbon dioxide equivalent (CO_2e) to account for the relative global warming potential (GWP) of each pollutant and to allow comparison between different greenhouse gases. GWP is a measure of a given pollutant’s ability to trap heat and depends on how well the gas absorbs energy and how long the gas stays in the atmosphere. Both CH_4 and N_2O emissions are converted to CO_2e emissions using GWP factors. GWP is calculated over a specific time, typically 100 years. In the air technical report, GHG emissions are presented in short tons, and CO_2e is based on the following 100-year values from the Intergovernmental Panel on Climate Change (IPCC) *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (AR5) (IPCC 2014): CO_2 GWP of 1, CH_4 GWP of 28, and N_2O GWP of 265 (SWCA 2019).

Because GHGs circulate freely throughout Earth's atmosphere, climate change is a global issue. The largest component of global anthropogenic GHG emissions is CO_2 (EPA 2016b). Fossil fuel use is the primary source of global CO_2 (EPA 2016b). Overall, U.S. energy-related emissions from the U.S. energy sector (fossil fuel combustion, natural gas systems, coal mining, mobile combustion, waste incineration, and other sources) accounted for a combined 84.0% of total U.S. greenhouse gas emissions in 2017 (EPA 2019a).

In 2018, total gross United States GHG emissions were 6,676.6 million metric tons (MMT) of CO_2e. Total United States emissions increased by 3.7% from 1990 to 2018; emissions increased from 2017 to 2018 by 2.9% (EPA 2020). Between 2017 and 2018, the increase in total GHG emissions was largely driven by an increase in CO_2 emissions from fossil fuel combustion. The increase in CO_2 emissions from fossil fuel combustion was a result of multiple factors, including increased energy use from greater heating and cooling needs due to a colder winter and hotter summer in 2018 compared to 2017 (EPA 2020). Methane emissions account for nearly 10% of emissions and have decreased by 7% since 2005 and 18.1% since 1990. The major sources of methane include enteric fermentation associated with domestic livestock, natural gas systems, and decomposition of wastes in landfills (EPA 2020).

Global climate is changing rapidly compared to the pace of natural climate variations that have occurred throughout Earth's history. Evidence for these changes consistently points to human activities, especially emission of GHGs, as the dominant cause. Global average temperature has increased by approximately 1.8°F from 1901 to 2016. Without significant emission reductions, annual average global temperatures could increase by 9°F or more by the end of this century (compared to preindustrial temperatures) (Hayhoe et al. 2018).

A recent study identified climate change issues relevant to resource management in all of Utah and Nevada, a small part of eastern California, a small part of western Colorado, southern Idaho, and western Wyoming (the Intermountain Region) (Halofsky et al. 2018). In the Plateaus subregion of the Intermountain Region (which covers the southern half of Utah, a small portion of western Colorado, and includes the proposed lease modification areas), median maximum temperature and median minimum temperature are projected to rise between 5°F to 10°F and 5°F to 12°F by 2100, respectively, depending on the climate model scenario (Halofsky et al. 2018). The greatest departure from historical temperatures by 2100 is projected to occur in summer. Projected median maximum temperatures for winter, spring, and autumn also move outside of historical ranges by 2100. Precipitation projections in the Plateaus subregion are highly variable with no discernible trend (Halofsky et al. 2018).

3.2.2 Environmental Impacts – Alternative A: No Action

Under the No Action Alternative, the BLM would not approve UEI's application for federal coal reserves on approximately 1,272.64 acres (317.84 acres added to lease UTU-014218 and 954.80 acres added to lease UTU-0126947) and the federal coal resources contained in the two lease modifications would not be mined. The coal reserves in the lease modifications would most likely be permanently bypassed.

Lila Canyon Mine would continue to operate at current production levels and emit air pollutants. Emissions of air pollutants would be limited by the 4.5 million TPY production rate condition established in its 2013 approval order. The projected mine life and operating plans of the Lila Canyon Mine are anticipated to extend through the year 2026. Other existing sources of air pollution (e.g., SCT, mobile sources), potentially including reasonably foreseeable future actions, would continue to impact air quality in the analysis area. The Hunter and Huntington Power Plants would continue operating as permitted.

3.2.2.1 Cumulative Effects

A choice of No Action would not contribute incrementally to the impacts of past, present, and reasonably foreseeable future actions, because under the No Action Alternative, the BLM would not approve UEI's application for federal coal reserves and would not allow extraction of the additional recoverable coal at this time. As a result, a No Action Alternative cumulative impacts analysis is not included.

3.2.3 Environmental Impacts – Alternative B: Proposed Action

Emissions of air pollutants at the Lila Canyon Mine are currently limited by a production rate condition established in its 2013 approval order. The mining of the proposed lease modification areas would extend by approximately two to three years the mining activities currently allowed under the 2013 approval order but would not increase the annual permitted emissions. The Proposed Action would not authorize a change in already permitted actions for the maximum production limitation or in annual emissions.

As previously stated, the Williams Draw LBA is contiguous with the Lila Canyon Mine and would use the Lila Canyon Mine surface facilities and infrastructure if offered for lease and if UEI is the successful bidder of the Williams Draw LBA. The proposed lease modification areas are also contiguous to the Lila Canyon Mine and would use Lila Canyon Mine facilities and infrastructure if the lease modifications are approved. Coal from both projects would follow the same potential paths from the Lila Canyon Mine to the SCT to its end destination. Both projects would occur under the Lila Canyon Mine's existing approval order (which limits annual production to 4.5 million tons of coal) and SCT's existing approval order (which limits coal throughput to 9.5 million tons of coal per rolling 12-month period). The Williams Draw LBA emission inventory is generally based on these approval order limits. Because the same facility production limits would remain in effect for the processing of coal from the proposed lease modification areas, the Williams Draw emissions data from the modeling protocol is used here as a proxy analysis for the proposed LMAs.

3.2.3.1 Direct Emissions

Under the Proposed Action, direct emissions would result from the mining of the coal in the lease modification areas and the hauling of the mined coal to the existing Savage Coal Terminal. These emissions would include CO, VOCs, NO_x, SO_2, PM_{10}, $PM_{2.5}$, HAPs, and GHGs.

Stationary sources of direct emissions at the Lila Canyon Mine include material handling conveyors, mine ventilation shafts, internal combustion engines, fuel storage tanks, a material processing screen and crusher, and surface operations. Except for particulate matter, all of the directly emitted criteria pollutants from mine operations would be from fuel combustion sources, such as mobile mining equipment, haul trucks, and stationary sources (e.g., emergency generators, firewater pump engines). Methane would be emitted by the ventilation air handling system required by the Mine Safety and Health Administration to reduce the combustion/explosion potential of the Mine's underground atmosphere (also known as ventilation-air methane or VAM). According to information provided by the Lila Canyon Mine, methane and VOC concentrations are below detectable limits in the ventilation exhaust air (BLM 2018).

Mobile sources include underground mining equipment (specialized industry-specific equipment designed for underground mining), aboveground sources such as heavy construction equipment for material handling and stockpile management, and light-duty gasoline trucks and light- and heavy-duty diesel trucks. On-road vehicles would include coal haul trucks and employee vehicles. Coal haul trucks would travel 30 miles each way to and from Lila Canyon Mine and the SCT. Emissions would also result from worker trips to and from the Mine. The average employee would travel 34 miles each way from the Lila Canyon Mine to Price, Utah (SWCA 2019).

At the Lila Canyon Mine, coal dust associated with mine surface operations is controlled on the conveyor system and at transfer points by enclosures and sprays. Dust from unpaved mine access roads is controlled by applying water or a dust-suppressing solution. Coal is reclaimed from the bottom of the coal stockpile directly onto a conveyor belt in an enclosed tunnel located under the pile. The coal moisture level in the coal pile is maintained at approximately 6.5% or greater by water sprays located on the main mine conveyor. The speed is also limited to 15 miles per hour along on-site haul roads. The following control measures were assumed in the development of the emission inventory:

- Coal bulldozing: Continuous water spray during material handling with a control efficiency of 62%.
- Coal handling and storage piles: Assumed best practice of chemical treatment and watering with a control efficiency of 90%.
- On-site haul roads: Assumed best practice of chemical treatment and watering and reduced speeds on roads to 15 miles per hour with a control efficiency of 95%.
- Underground nonroad engines: All engines are Tier 2 based on age, except mantrips which are Tier 3.
- Aboveground nonroad engines: All engines are Tier 1.
- Disturbed surface areas: Assumed best practice of chemical treatment and watering with a control efficiency of 50%.

Maximum annual direct emissions for the Proposed Action are summarized in Tables 3-4, 3-5, and 3-6. Emission calculations were based on the assumption of a maximum production rate of 4.5 million tons per year and coal loading and hauling operating hours of 24 hours per day, 365 days per year. Additional assumptions can be found in the air technical report (SWCA 2019).

Mobile source HAP emissions result from fuel combustion in both road and non-road vehicles. However, because VOC emissions from coal mine venting are poorly understood, a gas analysis of vented air at the Lila Canyon Mine was unavailable (methane venting emissions were below detectable levels), and the Colorado Underground Coal Mine Emission Inventory Tool (V1.0) does not include any HAP speciation emission factors; only HAP emissions from mobile sources were analyzed.

Table 3-4. Direct Criteria Pollutant Emissions

Emission Source	Annual Criteria Pollutant Emissions (tons per year)					
	CO	NO_x	VOC	SO_2	PM_{10}	$PM_{2.5}$
Conveyor transfers and drops	—	—	—	—	0.08	0.01
Crushing and screening*	—	—	—	—	1.11	1.11
Coal pile	—	—	—	—	2.20	0.33
Haul road – paved	—	—	—	—	1.33	0.33
Rock dust silo	—	—	—	—	<0.01	<0.01
Diesel storage tanks	—	—	0.09	—	—	—
Mine vents (includes underground equipment)	21.14	30.55	1.61	0.03	13.10	2.43
Aboveground equipment	28.63	23.44	3.10	0.02	1.43	1.31
On-road vehicles: coal haul trucks to Savage Coal Terminal (fugitive dust and exhaust)	13.21	48.29	2.64	0.09	10.49	4.07
On-road vehicles: worker commute (fugitive dust and exhaust)	11.41	1.01	0.29	0.01	5.75	1.41
Total	**74.39**	**103.29**	**7.73**	**0.15**	**35.49**	**11.01**

Source: SWCA (2019).

*There is no emission factor for $PM_{2.5}$. However, AP-42 suggests that the emission factors for PM_{10} may be used as an upper limit for $PM_{2.5}$ emissions from crushing. Conservatively, it was assumed that the emission factors for PM_{10} would also be an upper limit for $PM_{2.5}$ emissions from screening.

Table 3-5. Direct GHG Emissions

Emission Source	Annual GHG Emissions (tons per year)			
	CO_2	CH_4	N_2O	CO_2e
Conveyor transfers and drops	—	—	—	—
Crushing and screening	—	—	—	—
Coal pile	—	—	—	—
Haul road – paved	—	—	—	—
Rock dust silo	—	—	—	—
Diesel storage tanks	—	—	—	—
Mine vents (includes underground equipment)	67,883	1,622	2	113,769
Aboveground equipment	37,734	2	1	38,050
On-road vehicles: Coal haul trucks to Savage Coal Terminal (fugitive dust and exhaust)	n/a	n/a	n/a	10,306
On-road vehicles: Worker commute (fugitive dust and exhaust)	n/a	n/a	n/a	1,696
Total Maximum Annual Emissions	**117,618**	**1,625**	**3**	**163,821**
Life of LMAs Emissions*	**191,129**	**2,641**	**5**	**266,209**

Source: SWCA (2019).

n/a: Not applicable. On-road vehicles' CO_2e emissions were obtained from existing MOBILE 6 emissions factors. CO_2, CH_4, and N_2O emissions are listed as n/a for on-road vehicles even though CO_2e is calculated and listed. The totals do not currently include the emissions from source categories listed n/a.

Notes: GHG emissions are reported in short (U.S.) tons (1 metric ton = 1.10231 U.S. tons), and CO_2e is based on 100-year values. The global warming potential for each GHG is 1 for CO_2, 28 for CH_4, and 265 for N_20 (based on 100-year GHP AR 5 values).

* Calculated based on total LMAs' recoverable coal of 7.2 million tons as 1.625 factor of 4.5 million tons permitted annual maximum.

Table 3-6. Direct HAP Emissions

Emission Source	Annual HAP Emissions (tons per year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	Aldehydes
Conveyor transfers and drops	—	—	—	—	—	—
Crushing and screening	—	—	—	—	—	—
Coal pile	—	—	—	—	—	—
Haul road – paved	—	—	—	—	—	—
Rock dust silo	—	—	—	—	—	—
Diesel storage tanks	—	—	—	—	—	—
Mine vents	0.020	—	—	—	—	0.041
Aboveground equipment	0.009	—	—	—	—	0.010
On-road vehicles: Coal haul trucks to Savage Coal Terminal (fugitive dust and exhaust)	0.022	—	—	—	—	0.341
On-road vehicles: Worker commute (fugitive dust and exhaust)	0.007	—	—	—	—	0.005
Total	0.058	—	—	—	—	0.396

Source: SWCA (2019).

3.2.3.2 Indirect Emissions

Savage Coal Terminal and Coal Hauling Indirect Emissions

Under the Proposed Action, indirect emissions would result from handling the mined coal at the SCT; hauling the coal from the SCT to a regional coal-fired power plant via haul trucks or to a generic U.S. port located along the Gulf of Mexico via locomotive for export; and the combustion of coal. It is not expected that the SCT's approval order would need to be modified in response to the proposed project.

Stationary sources of emissions at the SCT include coal truck unloading facilities, material handling conveyors, a wash plant, internal combustion engines, a natural gas-fired boiler, fuel storage tanks, a fuel dispensing station, a material processing screen and crusher, and onsite haul roads. On-road vehicles would include coal haul trucks and employee vehicles. Locomotive emissions from hauling mined and processed coal are currently occurring in the analysis area and would continue under the Proposed Action.

The following assumptions were used in the development of the emission inventory:

- A 64-mile round trip along designated truck routes from the SCT to a regional coal-fired power plant, with an average capacity of 46 tons of coal per truck and a maximum of 11.2 trucks per hour (4.5 million tons of coal per year).
- A 3,200-mile round trip along designated rail routes from the SCT to a generic U.S. export port (the exact port of export is not known; a gulf port was selected as a reasonable approximation for emissions), with an average capacity of 120 tons of coal per railcar, 120 cars per unit train, and a maximum of 312.5-unit trains per year (4.5 million tons of coal per year).

Additional assumptions can be found in the air technical report (SWCA 2019). Tables 3-7, 3-8, and 3-9 summarize the indirect emissions from the handling of coal at the SCT and transporting the coal to its final destination. The totals in Table 3-7 and Table 3-8 represent the maximum indirect emissions if all project coal was shipped via locomotive to a generic U.S. export port located along the Gulf of Mexico.

Table 3-7. Indirect Criteria Pollutant Emissions

Emission Source	Annual Criteria Pollutant Emissions (tons per year)					
	CO	NO_x	VOC	SO_2	PM_{10}	$PM_{2.5}$
Savage Coal Terminal: Coal handling	4.35	9.25	7.27	0.28	42.39	6.21
On-road vehicles: Hauling coal from Savage Coal Terminal to regional power plant (fugitive dust and exhaust)	14.09	51.51	2.82	0.09	11.19	4.35
Locomotives: Hauling coal from the Savage Coal Terminal to a U.S. port along the Gulf of Mexico	873.15	3,246.77	124.32	3.10	75.43	73.17
Total indirect emissions when all coal is exported	**877.51**	**3,256.02**	**131.59**	**3.38**	**117.82**	**79.37**

Source: SWCA (2019).

Table 3-8. Indirect GHG Emissions

Emission Source	Maximum Annual GHG Emissions (tons per year)			
	CO_2	CH_4	N_2O	CO_2e
Savage Coal Terminal: Coal handling	6,383	<1	<1	6,506
On-road vehicles: Hauling coal from Savage Coal Terminal to regional power plant (fugitive dust and exhaust)	n/a	n/a	n/a	10,993
Locomotives: Hauling coal from the Savage Coal Terminal to a U.S. port along the Gulf of Mexico	336,951	26	9	339,945
Total indirect emissions when all coal is exported	**343,334**	**27**	**10**	**357,444**

Source: SWCA (2019).

n/a: Not applicable. On-road vehicles' CO_2e emissions were obtained from existing MOBILE 6 emissions factors. CO_2, CH_4, and N_2O emissions are listed as n/a for on-road vehicles even though CO_2e is calculated and listed. The totals do not currently include the emissions from source categories listed n/a.

Note: GHG emissions are reported in short (U.S.) tons, and CO_2e is based on 100-year values (IPCC 2014).

Table 3-9. Indirect HAP Emissions from Mobile Sources

Emission Source	Annual HAP Emissions (tons per year)					
	Benzene	Toluene	Ethylbenzene	Xylene	n-Hexane	Aldehydes
Transloading of crude oil	0.012	0.004	–	–	0.294	–
Fugitive component leaks	<0.001	<0.001	–	–	0.119	–
Railcar crude oil storage	<0.001	<0.001	–	–	0.038	–
Railcar boiler	–	–	–	–	–	–
Fuel storage tanks	–	–	–	–	–	–
Gasoline fueling	–	–	–	–	–	–
Emergency generator	0.082	0.036	–	0.025	–	0.170
Haul roads	–	–	–	–	–	–
Coal truck unloading	–	–	–	–	–	–
Coal crushing	–	–	–	–	–	–
Coal conveyor transfers and drops	–	–	–	–	–	–

Emission Source	**Annual HAP Emissions (tons per year)**					
	Benzene	**Toluene**	**Ethylbenzene**	**Xylene**	**n-Hexane**	**Aldehydes**
Coal railcar loading	–	–	–	–	–	–
Coal pile	–	–	–	–	–	–
Potash unloading	–	–	–	–	–	–
Potash rail car loading	–	–	–	–	–	–
Locomotives	0.802	–	–	–	–	0.108
Total	**0.897**	**0.040**	–	**0.025**	**0.451**	**0.278**

Source: SWCA (2019).

Coal Combustion Indirect Emissions

Coal combustion is considered an indirect impact because it is a reasonable end result of mining activity in the proposed LMA areas. If issued a modified lease for the Proposed Action, UEI could continue to provide coal to regional plants, or the coal could be transported to a U.S. port for export and combusted outside of the United States. UEI could also continue providing coal to the lime cement market and the spot market, or it could expand its customer base to other markets.

When combusted at a power plant, the coal mined from the proposed LMA areas would indirectly contribute to criteria pollutant, HAP, GHG, and other toxic air pollutant emissions. Domestic power plants are required to obtain air permits to operate; these permits restrict criteria and HAP pollutant emissions and require pollutant control technology to protect public health and the environment. Power plants must also ensure compliance with the NAAQS and any other applicable regulations (e.g., mercury). If a power plant accepts coal from a new source such as the proposed LMA areas, it would still have to maintain compliance with its air permit, any associated requirements, and emission limitations. Based upon historic coal combustion at Hunter and Huntington Power Plants (SWCA 2019), it is reasonable to assume for analysis purposes that all of the coal from the LMAs would be combusted at regional power plants such as Hunter and Huntington, under the limitations of their existing air permit and with appropriate pollutant control technology.

Combustion of the mined and processed coal would produce indirect emissions of criteria pollutants, HAPs, and GHGs (see Appendix E). Permitted emissions from regional power plants are provided in the air technical report (SWCA 2019:Tables 14 and 15).

To estimate emissions from the combustion of the mined coal, criteria and HAP emission factors from U.S. EPA AP-42, Section 1.1., Bituminous and Subbituminous Coal Combustion, were obtained (EPA 1998). The analysis assumes a maximum of 4.5 million tons of coal would be combusted per year. The heat content of the bituminous coal is assumed to be 11,695 British thermal units/pound, the sulfur content is assumed to be 1% by weight, and the ash content is assumed to be 11.25% by weight (SWCA 2019). Indirect annual criteria pollutant, GHG, and select HAP emissions from the combustion of the coal are summarized in Tables 3-10 and 3-11. Mercury emissions from the combustion of 4.5 million tons of coal annually would be approximately 70% of mercury emissions from Hunter and Huntington Power Plants combined, or approximately 4.1 lbs. These emissions are 0.2% of the 1,680 lbs (0.84 tons/year) shown in Table 3-10 (see Appendix E).

Table 3-10. Combustion of Coal Criteria Pollutant and HAP Emissions

Emission Source	Annual Criteria Pollutant and HAP Emissions (tons per year)								
	CO	NO_x	$PM_{2.5}$	PM_{10}	SO_2	VOC	Hydrochloric Acid (HCl)	Hydrofluoric Acid	Mercury
Coal combustion	1,125	33,750	15,188	58,219	85,500	21	2,700	338	0.84

Source: SWCA (2019).

Table 3-11. Combustion of Coal GHG Emissions

Emission Source	Annual GHG Emissions (tons per year)			
	CO_2	CH_4	N_2O	CO_2e
Coal combustion	10,822,685	1,276	186	10,907,614

Source: SWCA (2019).

Note: CO_2e emissions based on 100-year GWP for CO_2, CH_4, and N_2O.

3.2.3.3 Greenhouse Gas Emissions Assessment

The GHG emissions assessment assumes that 100% of the coal produced would be combusted. Regional GHG impacts from the Proposed Action include transport to the regional power plant (a fully loaded trip to the plant and an empty return trip) and combustion of all the produced coal by the regional power plant. Global GHG impacts from the Proposed Action include transporting the coal to a generic U.S. port (a fully loaded trip to the port and an empty return trip) and combustion of all coal produced. Calculated emissions of CO_2, methane, and N_2O were converted to CO_2e by the appropriate GWP factor. Table 3-12 summarizes the total annual direct and indirect GHG emissions that would be generated by the Proposed Action. The emissions in these tables are from Tables 3-5, 3-8, and 3-11.

Table 3-12. Summary of Estimated Direct and Indirect GHG Emissions

Emission Source	Total Annual GHG Emissions (tons per year)			
	CO_2	CH_4	N_2O	CO_2e
Direct operations (all direct mine emission sources, including coal haul trucks to Savage Coal Terminal and worker commute vehicles)	117,618	1,625	3	163,821
Indirect operations (i.e., Savage Coal Terminal, vehicles hauling coal to a regional power plant, and locomotives)	343,334	26	9	357,444
Indirect combustion of produced coal (Combustion of Lila Canyon–produced coal)	10,822,685	1,276	186	10,907,614
Total	**11,283,637**	**2,927**	**198**	**11,428,879**

Note: CO_2e emissions based on 100-year GWP for CO_2, CH_4, and N_2O.

Table 3-13 shows estimated GHG emissions for the Proposed Action (lease modification areas) compared with local, state, and national totals reported by the EPA, as well as a regional total from the states of Utah, Wyoming, New Mexico, and Colorado as reported in Appendix D.

Table 3-13. Project, Local, Regional, and National Greenhouse Gas Emissions

Project, Local, Regional, and National GHG Emission Comparison (million metric tons of CO_2e per year)				
Estimated Lease Modification Areas Emissions	**Emery County GHG Emissions in 2018***	**State of Utah GHG Emissions in 2018***	**Region (WY, CO, NM, UT) GHG Emissions in 2019††**	**U.S. GHG Emissions in 2017†**
11.4	13.5	35.1	940.1	6,456.7

* Data from EPA (2018).
† Data from EPA (2019a).
†† see Appendix D.

The Proposed Action–related CO_{2e} GHG emissions are estimated to be approximately 11.4 MMT per year. Proposed Action-direct CO_{2e} GHG emissions are estimated at 163,821 tons per year (Table 3-12), while emissions from indirect operations are estimated at 357,444 tons per year. The balance results from the indirect combustion of the Lila Canyon Mine produced coal. Comparison of the Proposed Action-related (indirect) CO_{2e} GHG emissions to the Emery County and Utah statewide emission totals is only appropriate at the national level as BLM does not exercise control over the specific end use of the coal produced from any individual federal lease and has no authority to direct or regulate the end use of the produced products. In addition, the indirect CO_{2e} GHG emissions are already accounted for in the existing county, state and national emission inventories as the Proposed Action involves lease modifications that would extend mining activities currently allowed but would not authorize a change in the already permitted actions for the maximum production of coal. As a result, the BLM provides an estimate of potential GHG emissions by assuming that all produced products would eventually be combusted. The Proposed Action-direct CO_{2e} GHG emissions are approximately 1.2% of Emery County's 2018 GHG emissions and 0.5% of statewide GHG emissions. The Proposed Action-direct and indirect related CO2e GHG emissions are approximately 0.2% of U.S. GHG emissions in 2017. The statewide emissions are from major industrial sources only. Statewide GHG emissions totals from other sectors (e.g., residential/commercial, transportation, and agriculture) are not currently available for 2018; the percentage of statewide GHG emissions attributable to the Proposed Action would be lower if all sectors were included.

Although this EA presents a quantified estimate of potential GHG emissions associated with the proposed LMA coal development at the maximum permitted rate (4.5 million tons of coal production per year), there is uncertainty in GHG emission estimates due to market-driven variations in production volumes, and transportation. Variation in markets and other factors would only reduce emissions/impacts from what is analyzed. Additionally, it is difficult to discern what end uses for the coal extracted from a particular leasehold might be reasonably foreseeable. The BLM does not exercise control over the specific end use of the coal produced from any individual federal lease and has no authority to direct or regulate the end use of the produced products. As a result, the BLM can only provide an estimate of potential GHG emissions by assuming that all produced products would eventually be combusted.

The climate change research community has not yet developed tools specifically intended for evaluating or quantifying end-point impacts attributable to the emissions of GHGs from a single source and has not identified any scientific literature to draw from regarding the climate effects of individual, facility-level GHG emissions. The current tools for simulating climate change generally focus on global and regional-scale modeling. Global and regional-scale models lack the capability to accurately represent many important small-scale processes. As a result, confidence in the accuracy of regional- and sub-regional-scale projections is lower than at the global scale. While climate models account for global emissions, they do not provide estimates for impacts from a single source in isolation of other sources.

There are no federal or state GHG emission standards to assist in evaluating a single source's potential impacts on climate. Thus, the GHG emissions estimates are presented here as a proxy for the potential climate change impact from the Proposed Action. The direct and indirect emission estimates previously provided are an estimate of the maximum potential for GHGs released into the atmosphere from mining to end use. Such emissions would incrementally add to the national and global emissions driving climate change (see Other Regulations in Section 3.2.1.1).

3.2.3.4 Near-Field Modeling Analysis

Because the same facility production limits would remain in effect for the processing of coal from the proposed LMA areas, the Williams Draw near-field modeling analysis is used here as a proxy analysis for the proposed LMAs. The modeling methodology, model configuration, meteorological data used, receptor placement, and other inputs and assumptions are described in the air technical report (SWCA 2019).

Air Quality Modeling Impact Assessment

A near-field criteria pollutant assessment was performed to estimate maximum potential impacts of criteria pollutants from Proposed Action emission sources. Predicted (modeled) maximum criteria pollutant concentrations are presented in Table 3-14. The maximum predicted concentrations vary based on the form of the NAAQS and the pollutant averaging period. For each criteria pollutant, the maximum predicted concentration is defined as:

- NO_2 and $PM_{2.5}$ annual average: The highest modeled annual averaged values over all 5 years.
- CO 1-hour and 8-hour, and SO_2 3-hour: The highest 2nd high (H2H) over 5 years.
- NO_2 1-hour: The 5-year mean of the 8th-highest (H8H) daily 1-hour maximum (average H8H of daily maxima)
- SO_2 1-hour: The 5-year mean of the 4th-highest (H4H) daily maximum.
- $PM_{2.5}$ 24-hour: The 5-year mean of the highest 8th high (H8H).
- PM_{10} 24-hour: The high 6th high (H6H) averaged over 5 years.

The modeling was performed using 5 years of hourly meteorological input data. The modeled impacts were also assessed at receptors within the modeled domain that are within the following three areas: Turtle Canyon Wilderness, Jurassic National Monument, at the site of the Cleveland Lloyd Dinosaur Quarry, and Desolation Canyon Wilderness (SWCA 2019).

Table 3-14. Maximum Ambient Concentrations from Modeling

Pollutant	Averaging Period	Modeled Concentration (μg/m³)	Background Concentration (μg/m³)	Maximum Ambient Concentration (μg/m³)	NAAQS (μg/m³)	Percent of Standard (%)
CO	1-hour*	14,643.4	1,718.0	16,361.4	40,000	40.9
	8-hour*	2,634.0	1,489.0	4,123.0	10,000	41.2
NO_2	Scenario 1 1-hour†	890.8	34.0	924.8	188.7	491.9
	Scenario 2 1-hour†	1,344.5	34.0	1,378.5	188.7	733.3
	Annual	53.6	12.0	65.6	100	65.6
PM_{10}	24-hour‡	535.6	42.0	577.6	150	385.1
$PM_{2.5}$	24-hour§	112.5	24.0	136.5	35	390.1
	Annual	24.2	6.1	30.3	15	252.9
SO_2	1-hour¶	20.0	18.0	38.0	195	19.4
	3-hour*	7.6	17.0	24.6	1,300	1.9

Source: SWCA (2019).

* Represents the high 2nd high concentration.

† Represents the 98th percentile concentration over a 5-year period.

‡ Represents the 4th-highest concentration over a 5-year period.

§ Represents the average of the highest 24-hour concentrations over a 5-year period.

¶ Represents the 99th percentile concentration over a 5-year period.

As shown in Table 3-14, the modeled plus background values for CO (1-hour and 8-hour), NO_2 (annual), and SO_2 (1-hour and 3-hour) are less than the NAAQS. Modeled concentrations of NO_2 (1-hour), PM_{10} (24-hour), and $PM_{2.5}$ (24-hour and annual) show potential exceedances of the NAAQS and are discussed in more detail below.

NO_2 Evaluation

Potential exceedances of the 1-hour NO_2 NAAQS are predicted to occur within 200 meters of the existing Lila Canyon Mine adits, but within the mine lease boundary. Both the adits and predicted exceedances are located inside the lease boundary. The relatively large contribution of mine vent emissions to the maximum 1-hour impact is explained by the receptor's very close proximity to the adits. Potential exceedances of the 1-hour NO_2 NAAQS are also expected to occur within 20 meters of the southern Lila Canyon Mine property boundary. They are expected to occur in areas that are difficult for the public to access due to terrain and vegetation. The relatively large contribution of mine vent emissions to the maximum 1-hour impact is explained by the receptor's very close proximity to the ambient air quality boundary used for the modeling analysis, the low exit velocity, the rugged terrain, and the elevated emissions associated with these activities (SWCA 2019).

Modeled ambient concentrations of NO_2 (1-hour and annual) at the three Class II areas of interest (Turtle Canyon Wilderness, the Jurassic National Monument at the site of the Cleveland Lloyd Dinosaur Quarry, and Desolation Canyon Wilderness) are all expected to be below the NAAQS. The 1-hour and annual NO_2 impacts at the closest Class II area are about 21.1% and 12.1% of their respective NAAQS (SWCA 2019).

PM_{10} Evaluation

The predicted H6H 24-hour PM_{10} concentrations indicate potential NAAQS exceedances within approximately 10 meters of the SCT's fence line and within 68 meters from the existing mine adits. The elevated impact near the mine adits can be attributed to emissions associated with underground mine activities, but the predicted exceedances are located within the lease boundary (SWCA 2019).

Conditions in the mine are cool and damp. A humid environment, combined with the moisture content of ore and development rock, is not conducive to dust generation. In addition, on August 1, 2016, Phase III of MSHA's respirable dust rule went into effect. This lowering of the concentration of respirable coal mine dust in the air that miners breathe is the most effective means of preventing diseases caused by excessive exposure to such dust (MSHA 2014). In addition, it would also limit the amount of PM_{10} emissions to the atmosphere from the mine adits. The PM_{10} modeling results can be considered conservative for two reasons: 1) no control was assumed for the humid conditions in the mine, and 2) the MSHA respirable dust limit was not accounted for in the modeling demonstration (SWCA 2019).

In accordance with 30 CFR 7.84(e), exhaust PM emissions would be diluted to 1 mg/m^3. In addition, 30 CFR 70.100 establishes concentration limits for respirable coal mine dust of 1.5 mg/m^3 at underground coal mines. A dilution of 1 mg/m^3 is equivalent to 1,000 µg/m^3, which is higher than the predicted PM_{10} and $PM_{2.5}$ modeled maximums at the adit exits (535.6 µg/m^3 for 24-hour PM_{10} and 112.5 µg/m^3 for 24-hour $PM_{2.5}$).

The modeled PM_{10} impacts from project emissions, in combination with conservative background concentrations, show that the Proposed Action would not cause an exceedance of the 24-hour NAAQS.

$PM_{2.5}$ Evaluation

The predicted H8H 24-hour average $PM_{2.5}$ concentration indicates a potential NAAQS exceedance. This potential exceedance is partially due to the high background ambient concentration of 24.0 µg/m^3, which is already 68.6% of the NAAQS (SWCA 2019). The predicted maximum impacts and potential exceedances of the 24-hour $PM_{2.5}$ NAAQS are expected to occur within 88 meters south and 50 meters north of the Lila Canyon Mine ambient air boundary and within 100 meters of the existing mine adits. Similarly, at the SCT, the area of potential exceedance is located within 59 meters of the southwest boundary.

Potential annual $PM_{2.5}$ exceedances are located at a maximum distance of 25 meters south of the Lila Canyon Mine, 35 meters from the existing mine adits, and 32 meters southwest of the SCT. Potential exceedances would occur in areas that are difficult for the public to access because of challenging terrain and vegetation. Furthermore, respirable dust emissions exiting the adits are those legally allowed in the mine atmosphere (an average concentration of respirable dust at or below 1.5 mg/m^3 in accordance with 30 CFR 70.100). The predicted exceedances around the existing adits occur and remain within the lease boundary (SWCA 2019).

As discussed for PM_{10}, because of the cool and damp mine conditions and the implementation of Phase III of MSHA's respirable dust rule, the $PM_{2.5}$ modeling results can be considered conservative because no control was assumed for the humid conditions in the mine, nor was the MSHA respirable dust limit accounted for in the modeling demonstration (SWCA 2019).

The modeled average daily and annual $PM_{2.5}$ concentrations do not exceed the NAAQS at any of the receptors within the modeled domain in the three Class II areas considered (SWCA 2019).

PSD Increment and Evaluation

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) was used to model impacts at the Class I areas and Class II areas within the 50-km near-field domain. No Class I areas are located within 50 km of the proposed lease modification areas. The nearest Class I area is Arches National Park, which is approximately 53 miles (85 km) to the southeast. Other nearby Class I areas and their respective distances from the proposed LMA areas are Canyonlands National Park (68 miles [109.5 km]) and Capitol Reef National Park (77 miles [124 km]). The potential PSD impacts were modeled at the edges of the modeling domain (geographic area covered by the model) in the direction of and closest to the Class I areas and compared to the corresponding PSD increments (SWCA 2019). The PSD increment is the allowable increase in a pollutant's concentration over the baseline concentration under the Clean Air Act. The PSD increments prevent the air quality in clean areas from deteriorating to levels set by the NAAQS.

The Class II areas within the modeling domain that were modeled are Turtle Canyon Wilderness (approximately 1.5 miles to the east of the proposed LMA areas), Desolation Canyon Wilderness (approximately 5.2 miles to the east), and Jurassic National Monument, at the site of the Cleveland Lloyd Dinosaur Quarry (approximately 19 miles to the west-southwest). Impacts predicted at these three areas were well below the NAAQS and PSD increments (the maximum predicted impact is projected to be less than 1.44% of the PSD increment) (SWCA 2019).

Four pollutants (PM_{10}, $PM_{2.5}$, SO_2, and NO_2) were modeled with respect to the maximum allowable PSD increments in Class I areas. For all three Class I areas (Arches National Park, Canyonlands National Park, and Capitol Reef National Park) analyzed, none of the Class I PSD increments were exceeded (SWCA 2019). Detailed modeling results can be found in the air technical report.

Secondary $PM_{2.5}$ Analysis

NO_X and SO_2 gases have the potential to form secondary $PM_{2.5}$. $PM_{2.5}$ formation from these precursors is highly uncertain and varies both regionally and seasonally due to atmospheric conditions. Assessing the Proposed Action's potential to form secondary $PM_{2.5}$ includes the analysis of monitoring data and the inclusion of EPA's Modeled Emission Rates for Precursors (MERPs) approach (SWCA 2019).

For $PM_{2.5}$, the critical air quality thresholds are assumed to be equal to significant impact levels (i.e., $PM_{2.5}$ daily = 1.2 μg/m^3, $PM_{2.5}$ annual = 0.2 g/μm^3). The estimated annual NO_X and SO_2 direct emissions from the Proposed Action were compared against the lowest (most conservative) illustrative $PM_{2.5}$ MERP value for these pollutants shown in the EPA's MERPs guidance of any source modeled by the EPA in the western United States (SWCA 2019).

NO_X and SO_2 precursor contributions to both daily average $PM_{2.5}$ are considered together to determine if the Proposed Action's air quality impact to secondary $PM_{2.5}$ would exceed the critical air quality threshold. In this case, the proposed emissions increases are expressed as a percent of the lowest MERP for each precursor and have been summed. A value less than 100% indicates that the critical air quality threshold would not be exceeded when considering the combined impacts of these precursors on daily and/or annual $PM_{2.5}$. The additive secondary impacts on daily $PM_{2.5}$ was calculated to be 9.33%.[4]

The presented method indicates that the emissions from the Proposed Action would not cause increases to secondary $PM_{2.5}$ concentrations in the area that exceed the critical air quality thresholds (SWCA 2019).

Ozone Analysis

To address whether the Proposed Action may cause or contribute to an exceedance of the ozone NAAQS, the ozone precursors, NO_x and VOC, were evaluated. The EPA guidance memorandum *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (EPA 2019b) was followed to determine the potential secondary pollutant impact resulting from the Proposed Action (SWCA 2019).

Using this methodology, potential ozone air quality impacts from the Proposed Action were compared against the applicable critical air quality threshold (1 ppb). The estimated annual NO_X and VOC emissions were compared against the lowest illustrative ozone MERP value shown in the EPA's guidance for any source modeled by the EPA in the western United States. A value less than 100% indicates that the critical air quality threshold would not be exceeded when considering the combined impacts of these precursors on daily and/or annual ozone. The additive secondary impacts on 8-hour ozone were calculated to be 56.87%.[5]

The presented method indicates that the Proposed Action is not expected to cause increases to secondary 8-hour ozone concentrations in the area that exceed the critical air quality thresholds (SWCA 2019).

Modeling for Visibility Impact Assessment

Federal land managers have developed a technique to screen small or distant sources so they would not cause or contribute to visibility impairment in Class I areas. The Federal Land Managers' Air Quality Related Values Work Group (FLAG) Report provides guidance on the protection of AQRVs and on how to assess potential visibility impairment from sources proposed near Class I airsheds (U.S. Forest Service et al. 2010). Because the proposed lease modification areas are more than 50 miles from the closest Class I area (Arches National Park), the FLAG 2010 initial screening guidance suggests summing the Proposed Action's tons per year emission rates for NO_X, SO_2, PM_{10}, and sulfuric acid mist (H_2SO_4), and dividing this value by the distance (km) from the proposed project to the nearest Class I area to evaluate potential impacts to AQRVs at that nearest Class I area. If this value (the Q/D value) is less than or equal to 10, no further analysis is required.

The distance from the proposed project to the closest border of the Class I area is 53 miles (85 km). Based on the estimated direct emissions from the Proposed Action in Table 3-4 and an estimated 0 tons per year of H_2SO_4 emissions, there would be a total of 139 tons per year of SO_2, NO_X, PM_{10}, and H_2SO_4. Dividing 139 by 85 results in a Q/D value of 1.54, which is less than 10. Therefore, the

[4] (103.29 TPY NO_x project /1,115 TPY NO_X daily $PM_{2.5}$ MERP) + (0.15 TPY SO_2 project/225 TPY SO_2 daily $PM_{2.5}$ MERP) = 0.092637 + 0.000667 = 0.093303 * 100 = 9.33%

[5] (103.29 TPY NO_X project /184 TPY NO_X MERP) + (7.73 TPY VOC project/1,049 TPY VOCMERP) =0.5613 + 0.00737 = 0.5687 * 100 = 56.87%

Proposed Action is not expected to adversely affect the nearest Class I area (or the other two farther away Class II areas). No additional visibility assessment is required (SWCA 2019).

Deposition Impact Assessment

A Level 1 deposition analysis was conducted for the Proposed Action to evaluate the possible effects of emissions on AQRVs in Class I and Class II areas of interest: Turtle Canyon Wilderness (approximately 1.5 miles to the east of the proposed LMA areas), Desolation Canyon Wilderness (approximately 5.2 miles to the east), and Jurassic National Monument, at the site of the Cleveland Lloyd Dinosaur Quarry (approximately 19 miles to the west-southwest). Results for the maximum deposition at each Class I and Class II area are provided in Table 3-15 for both nitrogen and sulfur (SWCA 2019). These results are compared to Deposition Analysis Thresholds (DATs). A DAT is defined as the additional amount of nitrogen or sulfur deposition below which estimated impacts from a proposed new or modified source are considered negligible (U.S. Forest Service et al. 2010).

Table 3-15. Estimated Maximum Sulfur and Nitrogen Deposition at Class I and Class II Areas of Interest (Level 1 analysis)

Constituent	DAT Value (kg/ha/year)	Arches National Park	Canyonlands National Park	Capitol Reef National Park	Turtle Canyon Wilderness	Jurassic National Monument at the Site of the Cleveland Lloyd Dinosaur Quarry	Desolation Canyon Wilderness
Sulfur	0.005	0.00005	0.0022	0.0002	0.00025	0.0007	0.0005
Nitrogen	0.005	0.00615	0.0984	0.0096	0.2399	0.0431	0.1980

Source: SWCA (2019).

Maximum deposition values for sulfur were all below the DAT of 0.005 kg/ha/year. Since nitrogen was unable to pass the Level 1 analysis (i.e., the maximum modeled deposition values at Class I and Class II areas were above the applicable DAT), a Level 2 deposition analysis was then conducted for this constituent. The Level 2 analysis uses AERMOD's deposition algorithms to provide an additional level of refinement beyond the Level 1 analysis (SWCA 2019). Level 2 results for the maximum nitrogen deposition at each Class I and Class II area are provided in Table 3-16.

Table 3-16. Estimated Maximum Nitrogen Deposition at Class I and Class II Areas of Interest (Level 2 analysis)

Constituent	DAT Value (kg/ha/year)	Arches National Park	Canyonlands National Park	Capitol Reef National Park	Turtle Canyon (then) Wilderness Study Area	Jurassic National Monument at the Site of the Cleveland Lloyd Dinosaur Quarry	Desolation Canyon (then) Wilderness Study Area
Nitrogen	0.005	3.4E-07	2.02E-06	4.6E-07	1.3E-05	1.6E-06	4.0E-06

Source: SWCA (2019).

Maximum deposition values for nitrogen were all below the DAT in the Level 2 analysis.

Hazardous Air Pollutants Impact Assessment

Small amounts of HAPs would be emitted as a result of the Proposed Action, as indicated in the emission inventory. HAPs can cause various adverse health effects, and high levels at the lease boundary could indicate the need for further analysis or mitigation strategies. Therefore, HAPs have been modeled in the AERMOD near-field analysis (SWCA 2019).

The HAP impact assessment compares modeled HAPs concentrations to the following health exposure levels:

- Reference Exposure Levels (RELs): Used to assess acute inhalation exposures (i.e., 1-hour averages) and represent the concentrations at or below which no adverse health effects are expected.
- State of Utah's Toxic Screening Levels (TSLs): Derived from the Threshold Limit Values published in the American Conference of Government Industrial Hygienists *Threshold Limit Values for Chemical Substances and Physical Agents* and based on exposure limits to a healthy adult in the workplace.
- Reference Concentrations (RfC): Represent an estimate of chronic inhalation exposure (i.e., annual average) rate to humans, including sensitive subgroups (children and elderly), without an appreciable risk of harmful effects.

Modeled results for HAPs are shown in Table 3-17. Short-term (1-hour) maximum HAP concentrations are compared to acute (1-hour) RELs and TSLs; long-term (annual) maximum HAP concentrations are compared to chronic (annual) RfCs.

Table 3-17 shows no exceedances of RELs, TSLs, or RfCs.

The potential for non-cancer effects was evaluated by dividing the air exposure concentration by the RfC for each pollutant. This results in what is known as the non-cancer Hazard Quotient (HQ). The HQ for each of the pollutants shown in Table 3-17 is less than 0.03. The total Hazard Index (HI) is calculated by summing the individual HQs for each pollutant. The total HI is compared to the acceptable HI, defined by the EPA as 1. For the proposed project, the total HI is 0.045532512. Therefore, non-cancer risks from the proposed project are not expected from any chemical, alone or in combination with others (SWCA 2019).

Table 3-17. Highest Modeled Results with Acute RELs and Chronic RfCs (1-hour and annual exposure)

HAP	Acute Analysis				Chronic Analysis		
	1-hour REL (μg/m^3)	TSL (μg/m^3)*	Maximum Modeled 1-hour Concentration (μg/m^3)	Complies with REL and TSL?	RfC (μg/m^3)†	Maximum Modeled Annual Concentration (μg/m^3)	Complies with RfC?
Acetaldehyde	470‡	4,504	11.68	Yes	9	0.09	Yes
Benzene	27‡	18	14.15	Yes	30	0.14	Yes
Formaldehyde	55‡	36.8	17.44	Yes	9.8§	0.27	Yes
n-Hexane	180,000¶	5,875	64.76	Yes	700	2.43	Yes
Toluene	37,000‡	2,512	1.57	Yes	5,000	0.04	Yes
Xylenes	22,000‡	14,473	1.10	Yes	100	0.02	Yes

Source: SWCA (2019).

* Utah Department of Environmental Quality (UDEQ) (2013).

† EPA (2019c).

‡ California Office of Environmental Health Hazard Assessment (2016).

§ The U.S. Agency for Toxic Substances and Disease Registry (ATSDR) chronic MRL of 0.008 ppm was used and converted to μg/m^3 where 1 ppm = 1,230 μg/m^3 for formaldehyde.

¶ National Institute for Occupational Safety and Health (2019).

To better characterize the risk associated with the modeled concentrations of HAPs, two estimates of cancer risk were performed (Table 3-18); one that corresponds to a most likely exposure (MLE), and one reflective of the maximally exposed individual (MEI). The analysis shows the potential for increased cancer risk for the MEI. The radius needed to predict below one-in-one-million cancer risk for the duration of MEI exposure period of 45 years was estimated at 31 meters from the existing mine adits.

The individual cancer risks for acetaldehyde and benzene are below one-in-one-million cancer risk for the MEI. Estimated cancer risk for formaldehyde is above the lower end of the threshold range of EPA's presumptively acceptable risks (1.0×10^{-4} to 1.0×10^{-6}), representing one excess cancer per 1 million people to one excess cancer per 10,000 people, respectively (SWCA 2019).

Table 3-18. Cancer Highest Risk Assessment: Carcinogenic HAP RfCs, Exposure Adjustment Factors, and Adjusted Exposure Risk

HAP	Carcinogenic Inhalation Unit Risk 1/(µg/m^3)*	MLE Assessment			MEI Assessment		
		Exposure Adjustment Factor	Cancer Risk	Within Acceptable Limits?	Exposure Adjustment Factor	Cancer Risk	Within Acceptable Limits?
Formaldehyde	1.300E-05	0.095	3.35E-07	Yes	0.643	2.27E-06	Yes
Acetaldehyde	2.200E-06	0.095	1.81E-08	Yes	0.643	1.22E-07	Yes
Benzene	7.800E-06	0.095	1.02E-07	Yes	0.643	6.89E-07	Yes
Total			4.55E-07	Yes		3.08E-06	Yes

Source: SWCA (2019).

* Annual average concentration.

The results in Table 3-18 show that modeled long-term risk from acetaldehyde and benzene for the MLE and MEI are below 1×10^{-6}. The MLE risk for formaldehyde is also below 1×10^{-6}. The MEI risk for formaldehyde is within the acceptable range of 1 to 1×10^{-4}. When benzene, acetaldehyde, and formaldehyde risks are added together, risks are below MLE and within the acceptable risk range (MEI) (SWCA 2019). The MEI analysis shows the potential for increased risk of cancer. Estimated cancer risk for formaldehyde is above the lower end of the threshold range of EPA's presumptively acceptable risks (1.0 × 10-4 to 1.0 × 10-6), representing 1 excess cancer per 1 million people to 1 excess cancer per 10,000 people, respectively. It should be noted that the maximum predicted concentrations and incremental risk estimates are very localized. The radius needed to predict below 1-in-1-million cancer risk for the duration of MEI exposure period of 45 years was estimated at 31 meters from the existing mine adits (SWCA 2019). It is highly unlikely that this MEI exposure situation could occur in reality; therefore, this risk is considered negligible.

3.2.3.5 Social Cost of Carbon

The Social Cost of Carbon (SCC) is an estimate of the economic impacts associated with an increase in carbon dioxide emissions (typically expressed as the cost in dollars per metric tons of emissions). A protocol to estimate the SCC associated with GHG emissions was developed by a federal Interagency Working Group to assist agencies in addressing Executive Order 12866, which requires assessment of the cost and the benefits of proposed regulations as part of their regulatory impact analyses. As explained in the Executive Summary of the 2015 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact*

Analysis Under Executive Order 12866, "the purpose of the 'social cost of carbon' (SCC) estimates…is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions." While the SCC protocol was created to meet the requirements for regulatory impact analyses during rulemakings, there have been requests by public commenters 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 EA for a number of reasons. First, this action is not a rulemaking for which the SCC protocol was originally developed. Second, on March 28, 2017, the President issued Executive Order 13783, which, among other actions, withdrew the technical support documents on which the SCC protocol was based and disbanded the Interagency Working Group. The Executive Order further directed agencies to ensure that estimates of the social cost of GHGs used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in Office of Management and Budget (OMB) Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates." In compliance with OMB Circular A-4, interim protocols have been developed for use in the rulemaking context. However, Circular A-4 does not apply to project-level NEPA analysis for a proposed project.

Further, NEPA does not require a cost-benefit analysis (40 CFR 1502.23), although it 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 of a SCC cost analysis solely would be unbalanced, potentially inaccurate, and not useful in facilitating the authorized officer's decision on the Proposed Action. Any increased economic activity, in terms of revenue, employment, labor income, total value added, and output that is expected to occur as a result of the Proposed Action is simply an economic impact, rather than an economic benefit, because such impacts might be viewed by another person as negative or undesirable impacts due to potential increases in local population, competition for jobs, and concerns that changes in population will 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, as mentioned above, 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 positive or negative effects of carbon emissions. The SCC protocol estimates economic damages associated with an increase in CO2 emissions 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 a SCC calculation represents the value of damages avoided if, ultimately, there is no increase in carbon emissions. However, 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 EIS, OSMRE estimated that the selected alternative had a total SCC ranging from approximately $4.2 billion to $22.1 billion depending on dollar value and the discount rate used. The total SCC for the No Action alternative ranged from $2.0 billion to $10.7 billion. Given the uncertainties associated with assigning a specific and accurate SCC resulting from the equivalent of two to three years of operation under the proposed Federal mining plan, and given that the SCC protocol and similar models were developed to estimate impacts of regulations over long time frames, this EA quantifies direct and indirect GHG emissions and evaluates these emissions in the context of county, state, and United States GHG emissions as discussed in Section 3.2.3.3 of this EA.

To summarize, this EA 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 Interagency Working Group, technical supporting documents, and associated guidance have been withdrawn; 3) NEPA does not require cost-benefit analysis; and 4) the full social effects of coal-fired energy production have not been monetized, and quantifying only the costs of GHG emissions would yield information that is incomplete, potentially inaccurate, and not useful.

3.2.3.6 Cumulative Effects

Past, present, and reasonably foreseeable future actions affecting air quality and greenhouse gas emissions are listed in Appendix C and discussed in Section 3.1.2 and Appendix D.

Current emissions in the air quality analysis area are reflected in the ambient air quality data shown in Table 3-2. Estimated levels of mercury and selenium are described in Appendix E. Mining of the proposed lease modification areas would not increase annual emissions currently occurring from the Lila Canyon Mine because it would be a continuation of existing mining operations (there would be no change in annual production). However, the life of the Mine would be extended for approximately 2 to 3 years. The proportion of emissions over the 2 to 3-year period that would be directly attributable to the mining of the proposed LMA areas is unknown. However, the emissions from the proposed LMA areas during this 2 to 3-year period would add incrementally to any emissions in the analysis area from reasonably foreseeable future actions, such as underground coal mining in the Williams Draw area, if offered and leased, or the SITLA leases (T. 16 S., R. 14 E., sec. 36 and T. 16 S., R. 15 E., sec. 32). These future actions would require environmental analysis and UDEQ-issued air quality permits to ensure that emissions do not exceed the NAAQS before any mining begins. The proposed Uinta Basin Railway would also contribute to air quality effects and GHG emissions through increased rail line traffic in the region. However, at this very early stage of that proposal, it is not possible to estimate such effects and/or emissions.

Other reasonably foreseeable future actions (see Appendix C) that could contribute criteria pollutant emissions include oil and gas leasing (if APDs are approved subsequent to the BLM’s quarterly oil and gas lease sales), the IACX Woodside Dome 1 APD, the Chalk Hills Mine Expansion, and projects that may cause temporary disturbances such as the East Carbon Junction Fiber project. These future actions would have to comply with their respective approval conditions, requirements, and permits.

The *Utah Bureau of Land Management Air Resource Management Strategy 2020 Monitoring Report* (BLM 2020b) describes GHG emissions from oil and gas wells. No APDs have been approved for the PFO planning area. As a result, there are no foreseeable short-term GHG emissions anticipated from oil and gas development. Future long-term GHG emissions estimates from oil and gas wells in Utah are estimated in the report. Total annual emissions in the PFO planning area are estimated to range from 3,051,780 to 3,470,352 MT CO_2e/year. The 2020 to 2050 aggregate emissions are estimated to range from 94.605 to 107.581 MMT CO2e.

Short-term foreseeable GHG emissions from oil and gas wells in Utah are estimated from approved APDs that have not been drilled to completion. However, not all APDs are drilled, and not all wells that are drilled go into production. Over a 5-year period (2015–2019), only 50% of statewide APDs were drilled, and 92% of the wells drilled went into production. For the same 5-year period, there has also been an average of 183 wells per year that were plugged. Using this information, it is assumed that of the current 267 approved APDs, approximately 135 wells will be drilled with 123 of them going into production. Factoring in the wells plugged each year results in a net decrease of 60 operating wells. Multiplying these numbers with statewide single well emissions factors results in construction emissions of 104,625 MT CO_2e, and a statewide average decrease in operation and combustion emissions of 27,178 MT CO_2e/year and 322,015 MT CO_2e/year, respectively (BLM 2020b).

The Lifting the Pause on the Issuance of New Federal Coal Leases for Thermal (Steam) Coal EA (Lifting the Pause EA) (BLM 2019) analyzes the potential effects on GHG emissions from the mining and combustion of federal coal that was applied for or authorized between January 2016 and April 2019. The Lifting the Pause EA estimates that the cumulative GHG emissions from combustion of federal coal that has been applied for or authorized would be approximately 6,903.6 MMT of CO_2e (20-year GWP) and 6,859.2 MMT of CO_2e (100-year GWP). This estimate includes coal tonnages from the proposed Lila Canyon Mine LMAs, the Williams Draw LBA, and the Walker Flat LBA. Total expected emissions resulting from the combustion of coal extracted from the approximately 1,280-acre SITLA lease areas are not included in the Lifting the Pause EA and have not yet been calculated as the coal is a mix of private, state, and federal minerals.

The IPCC's AR5 includes a summary of data from 30 different global climate models that evaluate the natural systems and feedback mechanisms contributing to climate variability (IPCC 2014). A range of global GHG emissions scenarios known as representative concentration pathways (RCP) were considered in the modeling analysis to assess potential degrees of climate change impacts. A stringent mitigation scenario (RCP2.6), a low emissions scenario (RCP4.5), an intermediate emissions scenario (RCP 6.0), and an aggressive emissions scenario (RCP8.5) are evaluated in the report. These scenarios correspond to atmospheric concentrations of CO_2 by the year 2100 of 421 ppm for RCP2.6, 538 ppm for RCP4.5, 670 ppm for RCP6.0, and 936 ppm for RCP8.5. The range of likely change in global surface temperature by 2050 ranges from 0.3 to 1 degree Celsius for the RCP2.6 scenario and from 0.5 to 2.0 degrees Celsius for the RCP8.5 scenario. Generally, the more stringent climate change mitigation, the lower the projected change in global surface temperatures. When discussing regional impacts, however, it is important to note that degrees of surface temperature increases vary from region to region. To discuss the cumulative impacts of GHG emissions for the project area, regional-scale projected impacts are discussed for the state of Utah.

The U.S. Geological Survey (USGS) has produced GHG estimates from the extraction, mid-stream (processing, transportation and distribution) and end-use combustion of fossil fuels produced on federal lands in the United States over a 10-year period (2005–2014) (Merrill et al. 2018). In 2014, nationwide gross GHG emissions from fossil fuels extracted from federal lands were 1,332.1 MMT CO_2e. Emissions from fossil fuels produced on federal lands represent, on average, 23.7% of national emissions for CO_2, 7.3% for CH_4, and 1.5% for N_2O over the 10 years included in this estimate (Merrill et al. 2018). Trends and relative magnitude of emissions are roughly parallel to production volumes. Regional and national coal and natural gas production trends and emissions and projected emissions are shown in Appendix D.

GHG emissions in the United States in 2017 totaled 6,456.7 MMT CO_2e (EPA 2019a). GHG emissions in the state of Utah in 2018 totaled 35.1 MMT CO_2e (EPA 2018). GHG emissions in Emery County in 2018 totaled 13.5 MMT CO_2e (EPA 2018). Because all the reasonably foreseeable future actions that involve coal mining are existing mining operations for which the future actions would extend production rather than increase production, the average annual GHG emissions from these mines are captured in these totals. The 34.3 MMT of direct and indirect CO_2e emissions from the coal mined from the proposed LMA areas over approximately 3 years (see Table 3-13) would contribute to statewide, regional, and national GHG emissions totals. Over that 3-year period, 34.3 MMT of CO_2e would average 11.4 MMT of CO_2e per year, representing approximately 0.2% of the total 2017 GHG emissions in the United States. The Proposed Action-direct CO_{2e} GHG emissions (see Table 3-12) are approximately 1.2% of Emery County's 2018 GHG emissions and 0.5% of statewide GHG emissions. It is important to note, the indirect CO_{2e} GHG emissions such as those from coal combustion at Hunter and Huntington Power Plants are already accounted for in the existing county, state and national emission inventories. The Proposal Action is a lease modification that would extend mining activities currently allowed, but would not authorize a change in the already permitted actions for the maximum production of coal. As a result, the BLM provides an estimate of potential GHG emissions by assuming that all produced products would eventually be combusted. GHGs, regardless of the source, contribute incrementally to climate change.

The BLM prepared the Colorado Plateau Rapid Ecological Assessment (CPREA) to provide regional scale information and assessment analysis on current and future conditions for the Colorado Plateau. This modeling analysis includes an assessment of potential climate change impacts (BLM 2012). In general, this modeling predicts future average annual temperature increases. Average annual precipitation is generally predicted to decrease (drier) through 2030 and increase (wetter) through 2060.

The USGS National Climate Change Viewer (USGS 2019) can be used to evaluate potential climate change at the state level. The viewer provides data showing projections of future climate trends under RCP emission scenarios RCP4.5 and RCP8.5. Data presented in the USGS Climate Change Viewer data can also be extrapolated to get a general understanding of impacts under RCP2.6 and RCP6.0. Generally, the RCP2.6 scenario can be assumed to contribute to a lesser degree of climate change impacts in the region, while the RCP6.0 can be assumed to contribute to impacts that are of lesser magnitude than RCP8.5 but of greater magnitude than RCP4.5. The USGS National Climate Change Viewer (USGS 2019) can be used to evaluate potential climate change at the state and county level. Projected changes to maximum and minimum temperatures in Utah resulting under a moderate GHG emissions scenario show both the maximum and minimum temperatures leveling off at approximately 5°F warmer than historical temperatures by the year 2100, while an aggressive GHG emissions scenario (RCP8.5) shows an increasing trend (approximately 5°F higher than the RCP4.5 scenario) at year 2100 (USGS 2019). The RCP4.5 and RCP8.5 scenarios forecast similar levels of climate impacts in the region over the next few decades; however, impacts over the next century diverge significantly. Because of uncertainties in the climate models, especially toward the end of the century, the impacts projected represent a forecast but are not certain to occur at the magnitudes projected. It is important to note that the high-end nature of the RCP8.5 scenario assumes a baseline without any future climate policy rather than the most likely "business as usual" outcome. Therefore, RCP8.5 could be considered unlikely to happen, while RCP4.5 and RCP6.0 would be more likely the representative scenarios.

3.3 Socioeconomics

The analysis area for potential direct, indirect, and cumulative socioeconomics effects comprises Emery County and communities within Emery and Carbon Counties that are located near the Lila Canyon Mine (i.e., East Carbon, Sunnyside, Price, Wellington, and Green River). This analysis area was chosen because it is the area where potential effects from employment, taxes, and revenue resulting from the development of the proposed lease modification areas would occur. This includes direct employment and income from mining jobs; indirect employment and income from coal transportation; the purchasing of mining equipment, fuel, and other vendor services and products; and royalties and tax revenues from coal production and sales.

3.3.1 Affected Environment

3.3.1.1 Employment

In 2017, total employment in Emery County was approximately 3,052 jobs (Utah Department of Workforce Services [UDWS] 2018). Trade, transportation, and utilities was the largest employment sector of Emery County, representing approximately 941 jobs (UDWS 2018). The second- and third-largest employment sectors in the county were government (approximately 884 jobs) and construction (approximately 299 jobs). Mining accounted for approximately 224 jobs in Emery County in 2017, or approximately 7% of total employment (UDWS 2018).

According to UDWS, the average monthly wage in Emery County in the mining sector was $6,446 in 2017 (UDWS 2018). The average monthly wage for all employment sectors in the county was $3,594 in 2017.

In 2017, total employment in Carbon County was approximately 8,414 jobs (UDWS 2018). Government was the largest employment sector of Carbon County, representing approximately 2,158 jobs (UDWS 2018). The second- and third-largest employment sectors in the county were trade, transportation, and utilities (approximately 1,793 jobs), and education and health services (approximately 1,321 jobs). Mining accounted for approximately 612 jobs in Carbon County in 2017, or approximately 7% of total employment (UDWS 2018).

According to UDWS, the average monthly wage in Carbon County in the mining sector was $7,875 in 2017 (UDWS 2018). The average monthly wage for all employment sectors in the county was $3,211 in 2017.

3.3.1.2 Taxes and Revenues

Fiscal effects from mining industry activities come in the form of various taxes and revenues paid by mining companies and the federal government to state and local governments where coal production occurs. Income taxes from coal mining wages are one of these fiscal effects because income taxes from jobs in the mining sector are collected by and paid to counties.

In addition to fiscal effects from taxing income, state and local governments receive other types of taxes, royalties, and funds as a result of mining activities in Emery County, such as:

- Property taxes paid on coal mines in Emery County.
- Property taxes paid on coal-fired power plants in Emery County (Hunter Plant and Huntington Plant).
- Rents and royalties paid for coal production on SITLA lands in Emery County.
- Federal coal royalty payments and disbursements to the State of Utah.

There are currently four active coal mines in Emery County. These mines and their recent production rates are listed in Table 3-19. Lila Canyon Mine reported 2,815,678 tons of coal production in 2018 (UEI 2019b) and 3,663,970 tons of coal in 2019 (DOGM 2020).

Table 3-19. Emery County Coal Mine Production (tons)

Mine	2013	2014	2015	2016	2017*
Emery II	4,000	–	–	–	129,000
Castle Valley #3	–	–	218,000	170,000	175,000
Castle Valley #4	875,000	1,061,000	757,000	724,000	783,000
Lila Canyon	257,000	335,000	350,000	1,587,000	1,629,000

Source: Boden et al. (2018).
* Preliminary

According to the ONRR, 2,671,777 tons of coal were produced from federal lands in Emery County in 2017 (ONRR 2019). The Department of the Interior applies an 8% royalty rate to coal extracted from underground mines on federal lands. Federal revenues from coal mining on federal lands in Emery County amounted to approximately $6.2 million in 2017 (ONRR 2018a, 2018b). Half of the revenue collected from royalties is disbursed back to the state of Utah, and half of the revenue disbursed to the state is typically disbursed to the county where the coal was extracted.

3.3.2 Environmental Impacts – Alternative A: No Action

Under the No Action Alternative, the BLM would not approve the proposed lease modifications and there would be no extraction of recoverable coal in the proposed lease modification areas. Therefore, there would be no direct or indirect impacts to the social and economic conditions of the analysis area. The local population, employment, housing conditions, and revenue would remain similar to current conditions because mining would continue in other areas of the Lila Canyon Mine. However, changes in other local industries could impact the socioeconomics of the analysis area. The extension of mining operations at the Lila Canyon Mine for an additional 2 to 3 years and associated employment and economic impacts would not occur under the No Action Alternative.

3.3.2.1 Cumulative Effects

Under the No Action Alternative, the BLM would not approve the proposed lease modifications. The current rates of employment, taxes, and revenue at the Lila Canyon Mine would continue under the No Action Alternative, but there would be no cumulative effect on socioeconomics in the analysis area from the approximately 3-year extension in the life of the Mine that would result from the Proposed Action, if it had been approved.

3.3.3 Environmental Impacts – Alternative B: Proposed Action

3.3.3.1 Employment

Under the Proposed Action, coal production and employment levels at the Lila Canyon Mine would not increase but would be extended for an additional 2 to 3 years. As of early 2020, the

Lila Canyon Mine employs 238 people. This approximate level of employment would be expected to continue during the additional 3-year time period. The continuation of direct employment effects would be minor over the extended life of the Mine because it would represent an estimated 2% of total employment in Emery and Carbon Counties.

The Proposed Action would also provide for secondary mining support jobs for an additional 2 to 3 years. Based upon 2017 Utah coal mining employment numbers, for every direct coal mining job in Utah, there are approximately 2.3 indirect/induced jobs (National Mining Association 2018). This translates to approximately 547 indirect jobs in place for the additional 3-year period of mine operation. Other indirect effects to the local economy would continue through the purchase and use of goods and services needed for mine operations, vehicles, and employees. The continuation of indirect employment effects would be minor over the extended life of the Lila Canyon Mine because it would represent an estimated 4% of total employment in Emery and Carbon Counties.

Under the Proposed Action, the mining sector's share of the workforce in Emery and Carbon Counties would not change. However, geographies with economies that focus narrowly on resource extraction, particularly on fossil-fuel development, can be subject to boom-and-bust cycles, as well as other economic challenges, such as slower long-term economic growth. Because of changes in external market pressures, natural resource economies are often vulnerable to unpredictable cycles of economic growth and recession. This can present challenges to communities in the form of fluctuating tax bases, demands for public infrastructure and social services, employment numbers, housing prices, and migration of workers into and out of a particular area.

3.3.3.2 Taxes and Revenues

Taxes and royalty payments from the mining of coal in the proposed lease modification areas would provide direct revenue to the state of Utah and federal government at approximately the same rate that currently occurs because the Proposed Action is a continuation of mining. However, the Proposed Action would add approximately 2 to 3 years to the life of the Lila Canyon Mine, which would extend the amount of time revenue is provided to the state and federal government.

In 2017, the average sales price for Utah coal was $35.28 per ton (U.S. Energy Information Administration 2019). Assuming the coal mined from the proposed lease modification areas area would be priced similarly, the 7.2 million tons of total coal produced from the proposed modification areas would result in approximately $254 million in total revenue. At a royalty rate of 8% for coal removed from an underground mine (Federal Coal Lease stipulations and 25 CFR 211.43), this would result in approximately $20.3 million in total federal royalty revenues, approximately $10.2 million in total state revenue from royalty disbursement, and approximately $5.1 million in total Emery County revenue from royalty disbursement. This Emery County disbursement is generally used for community impacts funds resulting from coal mining activities. The disbursement is commonly used for road maintenance, utility maintenance, and so forth. The approximately $5.1 million in total royalty disbursement to Emery County would result in an approximately $1.7 million in royalty disbursement to the county each year if we assume there would be 3 years of coal mining from the proposed lease modification areas.

3.3.3.3 Cumulative Effects

The Proposed Action would increase the life of the Lila Canyon Mine but would not affect employment levels at the Mine. The cumulative effects on demographics and housing in the socioeconomics analysis area would result from a 2 to 3-year extension of employment. The Proposed Action would incrementally add to the revenue and royalties of other active coal mines in the analysis area, including Emery II, Castle Valley #3, and Castle Valley #4. As shown in Table 3-19, total annual coal production at these three mines was approximately 1.1 million tons in 2017. Assuming these three mines were to produce at a similar rate over the 2 to 3 years during which coal would be mined from the proposed lease modification areas, these three mines would produce approximately 2.2 million tons to 3.3 million tons of coal during those 2 to 3 years. Combined with the 7.2 million tons produced from the proposed lease modification areas over those 2 to 3 years, this would be approximately 9.4 to 10.5 million tons. If we assume production occurs over 3 years and the price is $35.28 per ton, the total production from these four mines over 3 years would sell for approximately $370.4 million. The royalties paid to the federal government at an 8% royalty rate would be approximately $29.6 million over those 3 years, or approximately $9.9 million per year. The state would receive approximately $5.0 million per year from these royalties, half of which (approximately $2.5 million) would go to Emery County.

Other actions that, if approved, could contribute cumulatively to the employment and revenues in the analysis area include the Chalk Hills Mine Expansion, approved oil and gas APDs subsequent to the BLM's quarterly oil and gas lease sales, IACX Woodside Dome 1 APD, Twin Bridges Bowknot Helium project, EnerVest Peters Point APDs, E. Carbon Junction Fiber project, and the Uinta Basin Railway (see Appendix C).

3.4 Water Resources

3.4.1 Affected Environment

The analysis area for examining potential direct, indirect, and cumulative impacts to water resources is the analysis area for the Cumulative Hydrologic Impact Assessment (CHIA) for the Lila Canyon Mine (DOGM 2007). This analysis area was chosen because the hydrogeology and hydrology of the areas surrounding the proposed lease modification areas has been studied extensively as part of investigations related to mine permitting activities over the years (BLM 2000; Cirrus and Petersen 2017; DOGM 2007, 2010). The proposed lease modification areas lie within the area analyzed in the Lila Canyon MRP and the CHIA for the Lila Canyon Mine (DOGM 2007). The area analyzed in the Final Hydrology Assessment for Williams Draw Coal Tract (Cirrus and Petersen 2017) is within the cumulative impact area (CIA) defined in the CHIA and adjacent to the proposed lease modification areas. According to the CHIA, "the CIA is a designated area surrounding mining activity within which past, present, and anticipated or foreseeable coal mining activities may interact to affect the surface and groundwater" (DOGM 2007). The CIA of the CHIA is approximately 73,000 acres and extends from the Patmos Ridge on the east side to the Price River on the west side. Water resources in these areas are evaluated by use and interpretation of existing field monitoring data and reports. The analysis of effects includes the potential of 1) the direct interception of groundwater resources through mine dewatering, and 2) the alteration of groundwater recharge areas, flowpath areas, or discharge areas as a result of mining-induced fracturing from sub-surface subsidence.

Surface water resources in the proposed lease modification areas include ephemeral streams and two springs. There are no perennial streams in these areas. The closest perennial stream is Range Creek, located outside of the CIA identified in the CHIA, and beyond the Patmos Ridge to the east of the proposed lease modification areas. The Patmos Ridge defines the eastern boundary of the CIA evaluated in the CHIA. Groundwater resources in the proposed lease modification areas include active-zone and inactive-zone groundwater systems.

3.4.1.1 Groundwater

Groundwater in the proposed lease modification areas is extremely limited due to low precipitation and low recharge rates; it exists in two different geologic formations: the upper zone, Wasatch Group, and the lower zone, Mesaverde Group. The Wasatch Group consists of the North Horn—Flagstaff, and Colton Formations and extends throughout the eastern portion of the Lila Canyon Mine area (DOGM 2007). Some saturated zones of the North Horn Formation of the Wasatch Group are considered to be true aquifers using the definition as stated in Utah Administrative Code (UAC) R645-100 (as in effect February 1, 2019) where an aquifer "means a zone, stratum, or group of strata that can store and transmit water in sufficient quantities for a specific use" (UAC 645-100 2019). Groundwater in the Wasatch Group is an active-zone groundwater system because shallow-depth rock units are connected to a recharge area, the soils have sufficient capacity to store water and discharge it to springs, and groundwater migration to deeper inactive systems is mostly prevented by the presence of impermeable rock formations such as clay layers (DOGM 2007).

Groundwater in the Blackhawk Formation of the Mesaverde Group does not reside in a true aquifer using the above definition because "although a considerable volume of water may be stored, the water is not developed for a specific use, the strata do not transmit ground water to supply any water sources, and the water has no potential to be used or developed nor is it elemental to preserving the hydrologic balance in the permit and adjacent areas" (DOGM 2007). Further, the groundwater system is described as being inactive because it does not respond to seasonal and climatological variability. There is minimal interaction between groundwater in the Wasatch Group and Mesaverde Group as they are generally lenticular and perched or separated by impermeable clay layers. There are no groundwater discharge points from the Mesaverde Group anywhere in the CIA of the CHIA (DOGM 2007). A geologic section is shown in Figure 3-3.

Because the Blackhawk Formation is confined by low permeability shales and siltstones, where groundwater exists, groundwater movement is more likely to be horizontal rather than vertical. Horizontal flow in the deep, inactive-zone groundwater system, if it exists at all, is from higher elevation areas of the West Tavaputs Plateau and Range Creek toward lower elevations (DOGM 2007). Groundwater flow direction (perpendicular to the equipotential lines of hydraulic head) is to the northeast, which approximates the bedrock dip in the area (Cirrus and Petersen 2017).

Groundwater in the North Horn Formation of the Wasatch Group, the active-zone system, is primarily recharged by precipitation in the form of snowmelt, and discharges from springs at the surface. According to the CHIA, groundwater recharge in the Book Cliffs region has been estimated to be between 3% to 8% (Danielson and Sylla 1983) and 9% (Waddell et al. 1986) of the average annual precipitation. Recharge from precipitation is variable as the groundwater recharge rate is also influenced by timing and rate of precipitation, as well as soil type. Groundwater flow in the Wasatch Group is influenced by gravity and local geologic features such as bedrock fractures. In general, groundwater flows from areas of recharge toward areas of discharge.

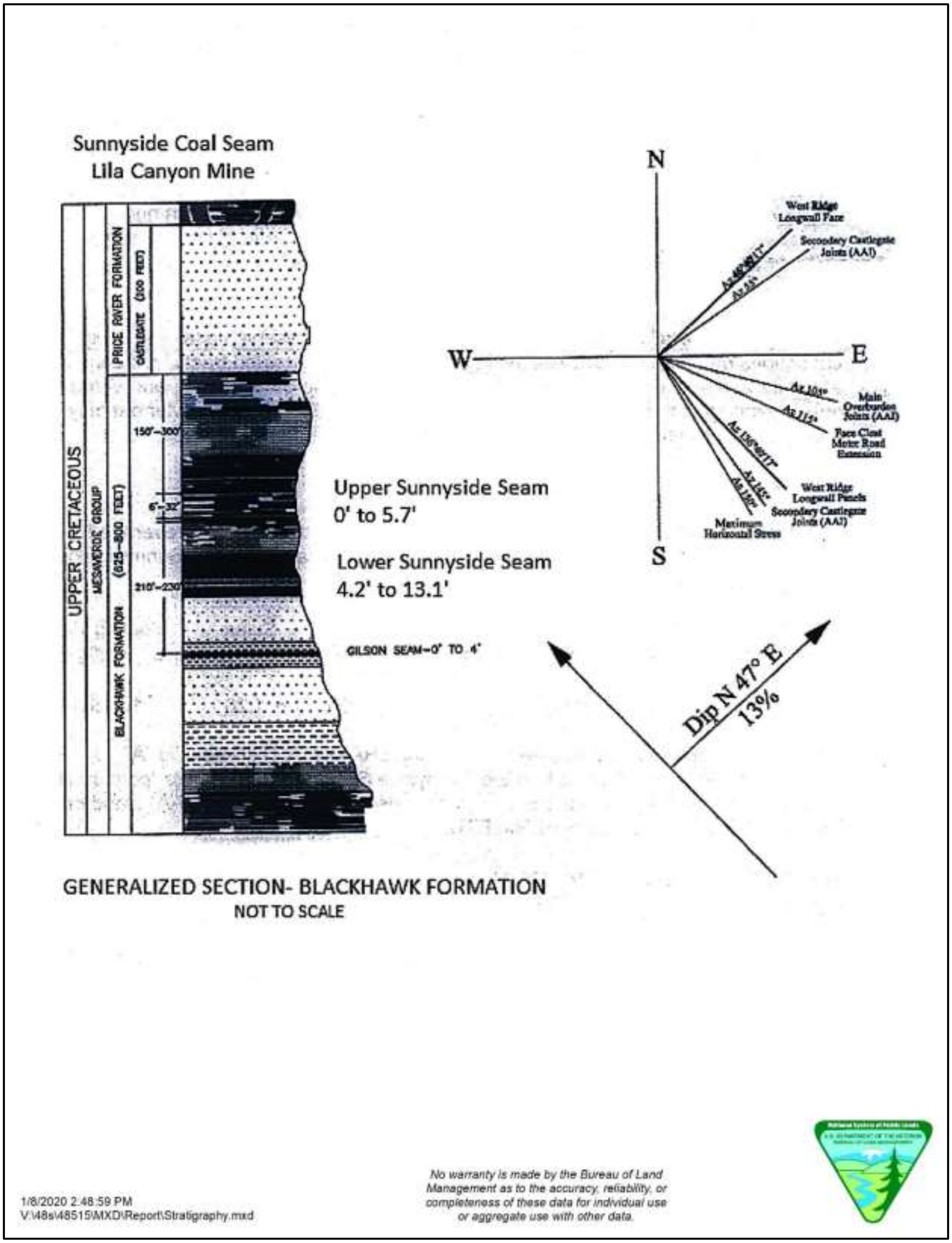

Figure 3-3. General geologic section.

Groundwater quality in the Wasatch Group can be measured by analysis of water samples collected from springs that discharge at the surface or by drilling wells. UEI has sampled several water monitoring stations on a quarterly basis since 2007, per conditions of the C/007/0013 Lila Canyon Mine permit approval. That information is reported electronically to the DOGM and summarized in reports to the DOGM permit supervisor.

Groundwater quality varies greatly in the Book Cliffs region and is mostly dependent on geologic formation and elevation. Total dissolved solids (TDS) is a measure of the total amount of dissolved constituents in water and is a commonly used indicator of groundwater quality. TDS concentrations in shallow groundwater in the Book Cliffs region range from 250 milligrams per liter (mg/L) to 2,000 mg/L and are driven by the type and amount of soluble minerals in the geologic formation (DOGM 2007). In addition, groundwater quality is typically better near areas of mountain recharge and diminished in lowland areas (DOGM 2007).

Three piezometers (IPA-1, IPA-2, and IPA-3), devices used to monitor the pressure or depth of groundwater, were installed in the Lila Canyon Mine DOGM permit area in the 1990s to monitor groundwater levels in the Blackhawk Formation of deep groundwater zone. Groundwater level data from the piezometers between 1994 and 2016 are summarized in the Final Hydrology Assessment (Cirrus and Petersen 2017). IPA-2 and IPA-3 are located in the same fault block. Water levels in the monitoring wells are monitored quarterly according to DOGM permit requirements. Water levels in these three wells remained relatively stable over more than two decades of monitoring—from installation in 1994 until approximately 2015 (Cirrus and Petersen 2017). Monitoring well IPA-3 was destroyed as a result of mining activities; it was sealed in October 2017. Water levels in the remaining two wells have generally decreased since 2015 (Figure 3-4).

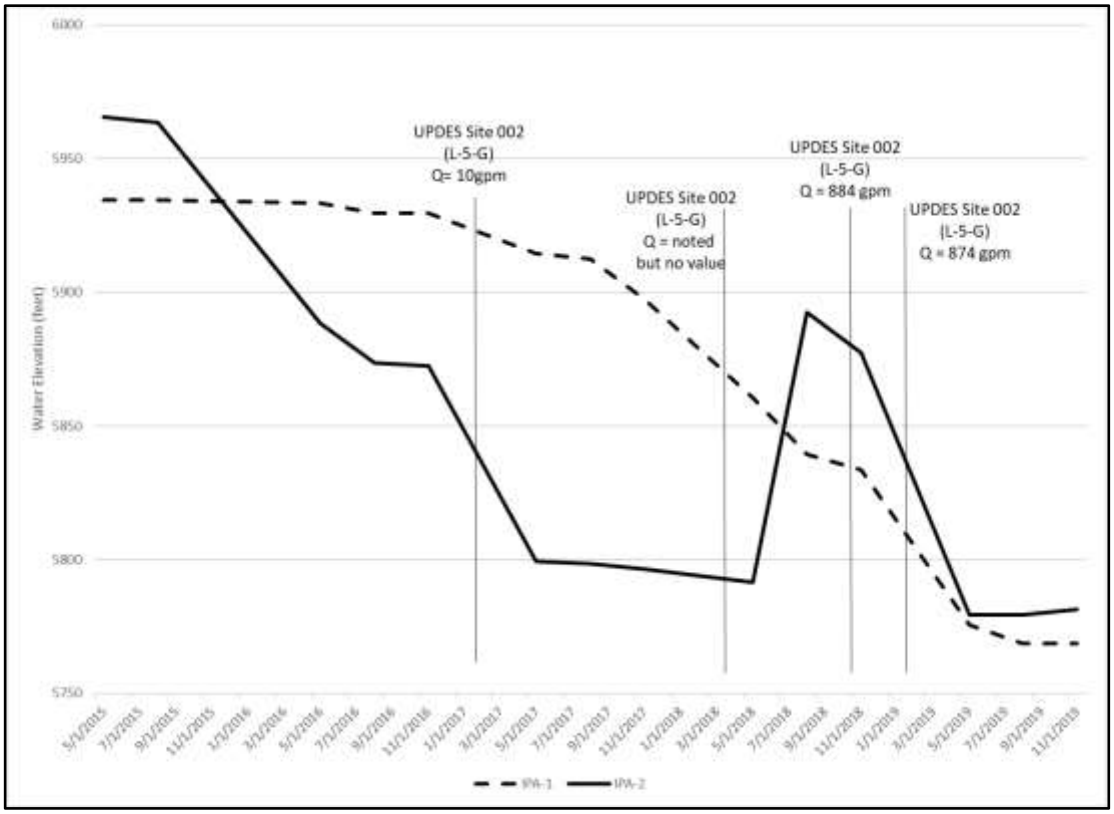

Figure 3-4. Hydrographs for monitoring wells IPA-1 and IPA-2 for the period Q2 2015 to Q4 2019 shown with discharge data from DOGM database.
Discharge data source: DOGM (2020).

IPA-1 is located in a different fault block than IPA-2 and IPA-3. DOGM noted in 2007 that water levels had risen continually at this location during the period of record (DOGM 2007). The rise in water level at IPA-1 is not understood, although the potential explanations offered by DOGM in 2007 (a leaking annular seal allowing surface water to reach the monitored zone, a bore-hole that had not yet reached equilibrium, and a Horse Canyon Mine exploration tunnel) were not related to mining activity (DOGM 2007).

Water levels lowered steadily in IPA-1 from the winter of 2016–2017 until the spring of 2019, compared with a more rapid decrease in IPA-2 from the summer of 2015 through the spring of 2017. IPA-2 then recorded a short-lived recharge that again rapidly depleted. Water levels in both wells appear to have leveled off at a water elevation of approximately 5,775 feet during the summer and fall of 2019.

The two wells (IPA-1 and IPA-2) are showing different responses to the mining activity as shown in Figure 3-4. IPA-1 is approximately 1.5 mile to the northeast of the IPA-2 and the two wells are separated by a fault (DOGM 2007), with screened intervals separated by approximately 600 feet in elevation differences. The screened intervals are the segments of the well equipped with filtering devices to allow intake of groundwater while keeping sand and gravel out of the well. IPA-1 is screened from 1,700 to 1,730 feet and IPA-2 from 1,101 to 1,116 feet below ground surface (Cirrus and Petersen 2017).

The monitoring wells are screened within the deeper aquifer described as an Inactive Groundwater Flow System by Mayo et al. (2003). Groundwater in this aquifer is characterized as old (2,000 to 20,000 years) with a general lack of hydraulic communication with the ground surface and active recharge zones (Cirrus and Petersen 2017). The system's general lack of communication, both vertically and horizontally, has been attributed to:

- an abundance of low-permeability rocks in the sequence;
- faults and fractures in the system that can provide for the movement of water in this system can be sealed by swelling clays (DOGM 2007); and
- the lenticular, discontinuous nature of the interbedded, more permeable, horizons that limit the extent of potential groundwater movement.

Generally, during the advancement of longwall mining in the region, little groundwater is encountered. Both roof and floor inflows are generally from sandstone channels within the supporting units, with occasional substantial inflows from fault-related drainage zones (Mayo et al. 2003). Longer-term mine inflows show a rapid decline in flow rates and ultimate extinction. Dewatering and subsidence related to mining have the greatest potential for impacting groundwater resources (DOGM 2007). Underground mining removes the support to overlying strata, and the subsequent fracturing and subsidence-induced caving can create conduits that allow groundwater to enter the mine.

Review of water quality memos from the DOGM database indicates that there was an initial low discharge recorded in the first quarter 2017 around the time of the initial lowering of water levels (see Figure 3-4). A period of greater discharge (approximately 880 gallons per minute [gpm]) was recorded in the fourth quarter 2018 to first quarter 2019, corresponding to what appears to be the final lowering of the potentiometric surface.

The two wells are showing different responses to the mining activity. IPA-1 is located approximately 1 mile north of IPA-2, and the two wells are separated by a fault (DOGM 2007). Although the mine plan has not been reviewed, it is inferred that IPA-2 is closer to the mine operations, as the third monitoring well, IPA-3, is located approximately 1 mile farther to the southeast of IPA-2. In addition to the potential difference in lithologies described above, its closer proximity to mine operations may explain the more rapid lowering of the potentiometric surface in IPA-2. Additionally, different responses to subsidence within the mine may also produce differing hydrographs.

Under Rule R645-301-751 of Utah Administrative Code, water that is discharged from a coal mine must meet applicable water quality standards. Any groundwater that exceeds the amount needed for mining operations would be stored, treated, then discharged in compliance with UPDES Permit No. UTG040024: General Permit for Coal Mining, which has effluent limitations so that discharged water will meet applicable state water quality standards (Utah Division of Water Quality [UDWQ] 2013). Permit limitations would not change under the Proposed Action. Water quality of the mine discharge is monitored on a monthly basis by UEI; results are reviewed by UEI and provided to UDWQ. The UPDES permit for the Lila Canyon Mine contains daily maximum concentration limitations for individual pollutants, as well as a discharge limit of 1 ton per day of TDS from all discharge points combined.

The Lila Canyon Mine UPDES permit identifies two discharges: 001 is discharge from the sediment pond and 002 is discharge from the underground mine. These discharges are being monitored as sites L-4-S and L-5-G, respectively. The UPDES permit specifies monitoring frequency and required parameters. UPDES site 002 (L-5-G) discharged an average of 894 gpm during 4th quarter of 2019 (DOGM 2020).

An additional discharge point has been proposed under UEI's draft UPDES Permit No. UT0026018 (UDEQ 2020). Underground mining operations in the Lila Canyon Mine are expected to intersect and cross an old portion of the historical Horse Canyon workings. These old workings are flooded and are expected to be drained over a period of time in order to allow safe access to the area of intersection of the new and old workings.

3.4.1.2 Surface Water

The proposed lease modification areas are in the Little Park Wash subwatershed (Hydrologic Unit Code [HUC] 140600071107), which is part of the larger Price River watershed. The proposed lease modification areas lie to the east of the Little Park Wash and contain several tributary drainages that carry ephemeral surface flows from the Patmos Ridge toward the Little Park Wash (Figure 3-5). Little Park Wash is the largest surface water feature in the vicinity and is an ephemeral stream channel that runs for approximately 14 miles before joining with Trail Canyon. Trail Canyon is connected to the Price River by a dry wash. The Price River ultimately joins the Green River about 19 miles south of Trail Canyon (Cirrus and Petersen 2017).

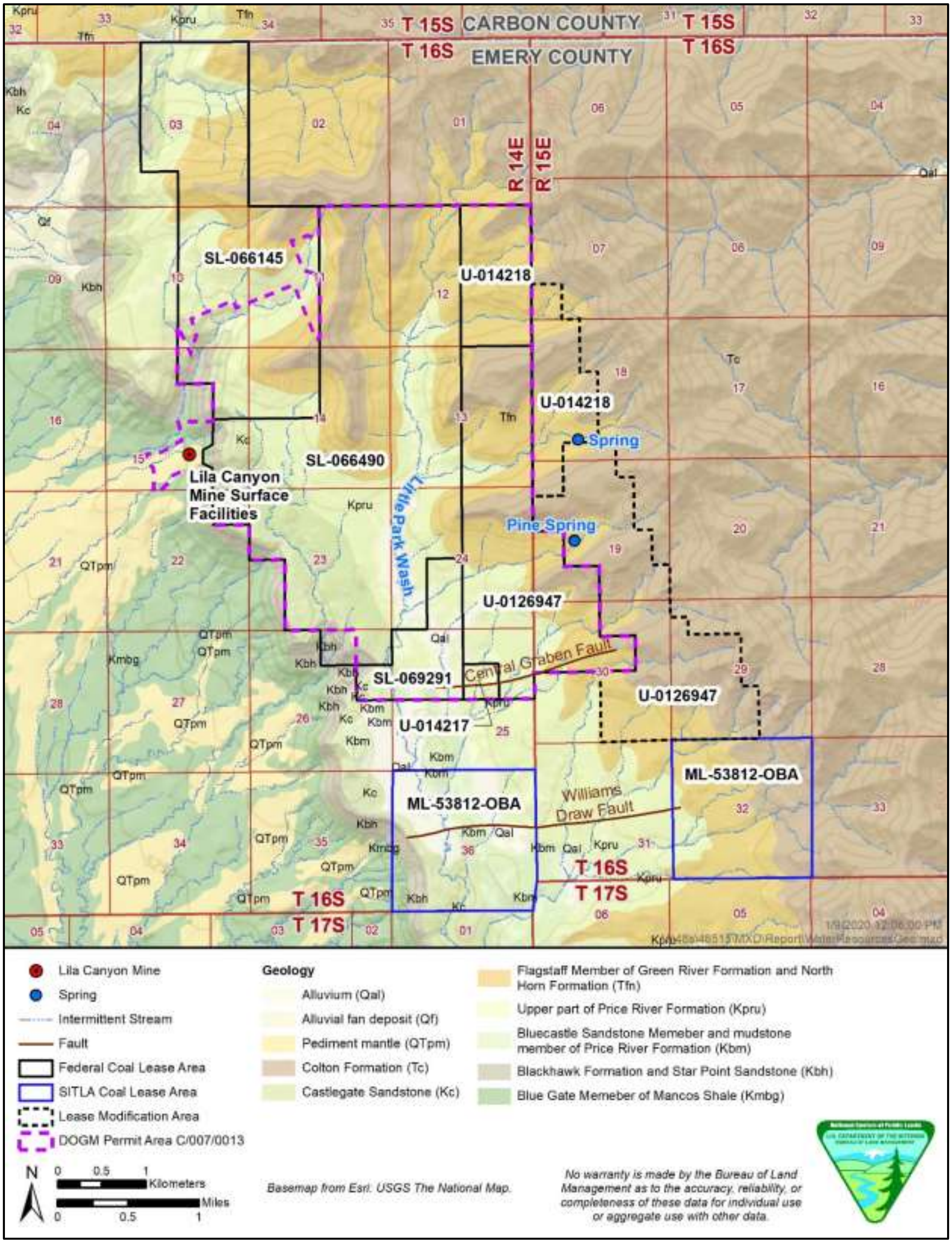

Figure 3-5. Geology and water resources.

Tributary channels in the proposed lease modification areas are mostly narrow, incised channels with coarse substrate. The tributary drainages enter the proposed lease modification areas at about 6,800 to 7,100 feet and enter the Little Park Wash at about 6,200 to 6,400 feet with a slope that ranges from 2% to 10%. The tributary channels are "generally narrow, somewhat incised, with relatively coarse substrate or bedrock" (Cirrus and Petersen 2017).

Surface flows in the tributary drainages are driven by precipitation events and seasonal runoff, which is typical of other arid watersheds in the Book Cliffs region. Field monitoring data collected from 2016 to 2017 indicates that "rain events have a greater influence on surface hydrology in comparison to snowmelt runoff" (Cirrus and Petersen 2017). Surface flows in the tributary drainages from low precipitation events rapidly infiltrate channel substrate and are unlikely to reach Little Park Wash (Cirrus and Petersen 2017). Flow data to characterize the amount of surface flow from tributary drainages in the proposed lease modification areas are not available.

According to the CHIA for the Lila Canyon Mine, "some of the draws that supply these stream channels contain springs, which flow perennially for short distances then filter into the channel deposits. All the springs on the CIA flow less than 10 gpm [gallons per minute] and most flow only one or two gpm" (DOGM 2007). Springs that discharge from the active-zone groundwater system in the North Horn Formation are generally located in existing stream channels. As indicated above, surface flow from springs only travels for a short distance in the stream channels before infiltrating into the ground. In general, springs discharging from the North Horn Formation are active in the spring and early summer and are dry for the remainder of the year (Cirrus and Petersen 2017).

Beneficial uses for surface waters of the state are assigned by the UDWQ for each assessment unit in Utah. Assessment units are discrete sub-watershed units delineated by UDWQ. The proposed lease modification areas lie within the Grassy Trail Creek Lower assessment unit, which includes Grassy Trail Creek and tributaries from the Price River confluence to Grassy Trail Creek Reservoir. UDWQ has classified surface waters in this assessment unit with the following designated beneficial uses (UDEQ 2019):

- Class 2B: Protected for infrequent primary contact recreation
- Class 3C: Protected for nongame fish and other aquatic life
- Class 4: Agricultural uses

Water quality criteria consist of numeric thresholds for individual pollutants and narrative descriptions of desired conditions. Numeric criteria for individual pollutants are found in UAC R317-2 (Standards of Quality for Waters of the State). Numeric criteria for established beneficial uses as described in UAC R317-2 serve as a baseline for understanding results of water quality monitoring. The following narrative criteria applies to surface waters in the proposed lease modification areas:

> It shall be unlawful, and a violation of these rules, for any person to discharge or place any waste or other substance in such a way as will be or may become offensive such as unnatural deposits, floating debris, oil, scum or other nuisances such as color, odor or taste; or cause conditions which produce undesirable aquatic life or which produce objectionable tastes in edible aquatic organisms; or result in concentrations or combinations of substances which produce undesirable physiological responses in desirable resident fish, or other desirable aquatic life,

> or undesirable human health effects, as determined by bioassay or other tests performed in accordance with standard procedures; or determined by biological assessments in Subsection R317-2-7.3 (UAC R317-2 2019).

Waters protected for infrequent primary contact recreation (beneficial use Class 2) and aquatic-life uses (Class 3) do not have a TDS numeric criterion. The numeric criterion for agricultural uses (Class 4) is typically 1,200 mg/L; however, UDWQ has developed a site-specific TDS standard of 3,000 mg/L for the Price River and tributaries from the confluence with the Green River to the confluence with Soldier Creek.

There are two springs in the proposed lease modification areas: L-8-G and L-9-G (Pine Spring) (see Figure 3-5). The water rights associated with springs L-8-G and L-9-G are 91-2538 and 91-2539 respectively (DOGM 2010). The water right associated with L-8-G is used for stock watering and is owned by the State of Utah (DOGM 2010). The water right for L-9-G is owned by the BLM (Utah Division of Water Rights 2019). According to the CHIA, L-9-G has been used for cattle and wildlife in the past, although the metal spring box has been washed downstream (DOGM 2007).

Water samples have been collected from the two springs in the proposed lease modification areas since the 1990s. The first sampling efforts were conducted in the early 1990s to establish baseline conditions. UEI has collected samples from the two springs in the proposed lease modification areas (which discharge from the North Horn Formation) on a quarterly basis since 2007 per conditions of the C/007/0013 Lila Canyon Mine permit. Results are reported to DOGM. Water quality data for the two springs was not readily available prior to 2015. TDS concentrations measured at spring L-8-G between 2015 and 2018 range between 376 mg/L and 648 mg/L with an average concentration of 540.8 mg/L (UEI 2019c). TDS concentrations measured at spring L-9-G since 2015 range between 629 mg/L and 901 mg/L with an average concentration of 750 mg/L. Spring L-9-G does not flow year-round according to discharge data received from UEI (UEI 2019c). Other water quality parameters monitored by UEI at springs L-8-G and L-9-G, including alkalinity, hardness, cations, and chloride, do not have State of Utah numeric criteria.

Discharge at springs L-8-G and L-9-G was measured at the same time as the water quality samples. The average discharge at spring L-8-G between 2015 and 2018 was 0.436 gpm, or 0.0009 cubic feet per second (cfs). Average discharge at spring L-9-G during the same time period was 0.886 gpm, or 0.001 cfs.

There is no evidence to suggest that the springs in the proposed lease modification areas have impaired water quality with regard to State of Utah numeric criteria for designated beneficial uses. UDWQ assessed water quality data collected within the Grassy Trail Creek Lower assessment unit (UT14060007-012) in the most recent Integrated Report and determined there was insufficient data to make an assessment determination for the assessment unit (UDWQ 2016). Springs L-8-G and L-9-G were not assessed by UDWQ.

Water quality of springs that discharge from the North Horn Formation in the nearby Williams Draw Coal Tract is assumed to be similar to water quality of springs that discharge from the North Horn Formation in the proposed lease modification areas. Water samples were collected on a quarterly basis from springs that discharge from the North Horn Formation in the Williams Draw Coal Tract as part of a comprehensive hydrological survey conducted by Cirrus from September 2016 to June 2017.

Water quality parameters measured by Cirrus and Petersen (2017) in the 2016–2017 hydrologic survey indicate that springs discharging from the North Horn Formation in the Williams Draw Coal Tract typically flow less than 1 gpm and have water quality that is supporting beneficial uses. Field measurements of dissolved oxygen, pH, and temperature were within acceptable limits as set forth in UAC R317-2, as are measurements of TDS and other water quality constituents (Cirrus and Petersen 2017). TDS values were variable and ranged from 560 mg/L to 3,706 mg/L, with an average value of 1,504 mg/L (Cirrus and Petersen 2017).

3.4.2 Environmental Impacts – Alternative A: No Action

Under the No Action Alternative, the effects of mining UEI's federal coal leases on surface water and groundwater would continue as described in approval documents for ongoing activities in the Lila Canyon Mine. There would be no direct or indirect impacts to surface water or groundwater resulting from mining of the proposed lease modification areas as the BLM would not approve modification of the existing leases. Ongoing indirect effects as a result of coal combustion, such as at the Hunter and Huntington Power Plants, are described in Appendix E.

3.4.2.1 Cumulative Effects

There would be no cumulative effects to water resources under the No Action Alternative, as the existing coal leases would not be modified to include the proposed lease modification areas.

3.4.3 Environmental Impacts – Alternative B: Proposed Action

As with the discussion of water resources, existing information from investigations related to mine permitting activities is used for analysis of potential impacts to water resources from mining coal resources in the proposed lease modification areas of the Lila Canyon Mine.

Under the Proposed Action, coal in the proposed lease modification areas would be mined using the existing infrastructure from the Lila Canyon Mine, and no additional surface disturbances are expected. Under the Proposed Action, there exists the potential for 1) the direct interception of groundwater resources through mine dewatering, and 2) the alteration of groundwater recharge areas, flowpath areas, or discharge areas as a result of mining-induced fracturing from subsidence. Because of the depth of the mining operation and lack of surface disturbance, no impacts to surface water resources are expected. It should be noted, however, that DOGM (SMCRA) permits require water replacement stipulations, should any surface water be disrupted. Indirect effects as a result of coal combustion, such as at the Hunter and Huntington Power Plants, are described in Appendix E.

3.4.3.1 Groundwater

Under the Proposed Action, impacts to groundwater resources from mine dewatering are expected to be minimal because coal mining production would not increase beyond currently permitted levels. Water encountered during mining is typically stored and used within the Mine for dust suppression or for other uses; it may be stored and re-used several times prior to any discharge. As mining shifts into the proposed lease modification areas, this cycle of water use would continue. Mine dewatering is the removal and discharge of excess groundwater that has infiltrated into a mine or has been intercepted by mining processes. Because mining at the Lila Canyon Mine would occur at a depth of 2,500 to 3,000 feet below the surface, the only groundwater likely to be encountered would exist in the deep, inactive-zone groundwater system (lenticular and perched). As discussed in Section 3.4.1.1 of this EA, DOGM concluded that groundwater in the inactive-zone groundwater system of the Blackhawk Formation of the Mesaverde Group is not hydrologically connected to the shallow recharge aquifers (DOGM 2007). Therefore, mine dewatering rates would naturally decline over time after the first encounter with groundwater (BLM 2013). However, because of the complex nature of regional faulting and groundwater flowpaths as well as uncertainty about the exact location and displacement along the primary faults (Cirrus and Petersen 2017), there may be potential for connectivity between shallow aquifers and deeper groundwater zones. Regional groundwater information that has been collected in the vicinity of the MRP and LBA area and similar hydrogeologic conditions in surrounding areas strongly suggest that the groundwater would most likely not be lost to the deep, inactive-zone groundwater system.

In a typical underground mining scenario, mining-related subsidence generally has the potential to affect water resources through the formation of new fissures, or in the case of the Lila Canyon Mine, both new fissures and the expansion of existing fissures that can alter the flow of groundwater and change the surface water and groundwater interaction. Subsidence has the potential to connect aquifers that were previously disconnected, change the rate and direction of groundwater movement, and change groundwater recharge and discharge rates. Discharge rates of the two springs in the proposed lease modification areas are monitored by UEI and reported to DOGM.

As discussed in Section 2.4.2.3 of this EA, mining-related subsidence is unlikely in coal mining operations with deep cover as is found in the proposed lease modification areas, and any mining-related subsidence effects to water resources would be mitigated by the physical properties of the geologic formations in the lease modification areas. According to the CHIA, “It is very unlikely that subsidence or subsidence fractures would reach the springs or recharge sources to cause any impacts” (DOGM 2007).

The proposed mining in the proposed lease modification areas would take place under 2,500 to 3,000 feet of cover, making subsidence-related effects to springs unlikely. This assessment comes from existing hydrogeologic investigations associated with nearby mine permitting activities. According to the Williams Draw Hydrologic Assessment, “visual observations over the Book Cliff mines…indicate little potential for any permanent fracturing at cover exceeding 1,000 feet” (Cirrus and Petersen 2017). The CHIA for the Book Cliffs Area V states that, “the areas of upper zone ground-water recharge and discharge on the Little Park Wash side of Patmos Ridge are outside the limits of projected subsidence” (DOGM 2007) (MRP-Part B, Plate 7-1A). Finally, according to the Lila Canyon Project Environmental Assessment, “the presence of a generally thick overburden serves to dampen subsidence” (BLM 2000).

Mining would occur at approximately 1,900 feet below Pine Spring, and between 1,500 to 2,200 feet below spring L-8-G (DOGM 2007). At this depth of cover, mining-related subsidence is not anticipated to impact surface water or shallow groundwater. Because subsidence-related impacts on springs in the lease modification areas are expected to be minimal, there is no reason to anticipate that impacts on groundwater quality might occur. As previously mentioned, the springs are connected to the shallow recharge area, which is well above the zone where any coal mining would take place; therefore, it is unlikely that water quantity would be affected by the Proposed Action. Fractures at the surface can be filled in rapidly because the natural erosion process will wash fine substrate over cracks during rainstorms or snowmelt.

Any potential impacts to groundwater resources under the Proposed Action from mining-related subsidence would be mitigated by characteristics of the geologic formations in the proposed lease modification areas. Fractures and fissures introduced by subsidence from mining activity can be sealed by clays that are highly plastic and have the tendency to swell. Clays are abundant in the geologic formations surrounding the active-zone and inactive-zone groundwater systems in the proposed lease modification areas. When groundwater is present, any surrounding shale layers tend to swell and seal subsidence fractures. Water movement through newly created fractures or fissures is restricted by this phenomenon (DOGM 2007).

3.4.3.2 Surface Water

No impacts to surface water resources in the proposed lease modification areas are expected from mining-related subsidence due to the depth of the mining operations and lack of surface disturbances. Furthermore, there is no reasonably foreseeable mechanism for surface water quality in the proposed lease modification areas to be impacted by mining operations under the Proposed Action.

There would be no impacts to surface water resources in the proposed lease modification areas due to mine dewatering because the Lila Canyon Mine typically reuses and recycles water within the Mine, the discharge point is an ephemeral wash, and based upon calculations of a continuous flow, water from the Mine would not reach the Price River approximately 12.7 miles away.

Water not used or stored in the Lila Canyon Mine or lost to evaporation will be discharged to the Right Fork of Lila Wash via UPDES 002 (Site L-5-G). Rule R645-301-751 requires that a coal mine discharge must meet state and federal water quality and discharge standards. According to the CHIA, potential discharges of 500 gpm (1.1cfs) and a maximum discharge rate of 2,080 gpm were evaluated. With a constant flow rate of 2,080 gpm, (4.63 cfs), the mine discharge effect would be limited to a distance of 8.5 miles. At 500 gpm (1.1 cfs), the mine discharge would flow for 3.4 miles before completely infiltrating into the alluvium (DOGM 2007). The discharge was compared to the bankfull channel level. It was found that the Mine discharge is significantly less than the bankfull level and that a continuous discharge would not reach a perennial stream (DOGM 2007).

According to the CHIA, no impacts are expected if mine water is discharged. Groundwater intercepted in the Mine is stored in sumps and treated prior to any discharges. Discharges are monitored by the state under the UPDES program.

3.4.3.3 Cumulative Effects

The past and present actions that would affect water resources are underground mining operations. Reasonably foreseeable future actions in the vicinity of the proposed lease modification areas are discussed in Section 3.1.2 of this document. Past, present, and reasonably foreseeable future actions are listed in Appendix C.

The spatial analysis area to examine cumulative effects to water resources extends to the CIA boundary from the CHIA (DOGM 2007). The CIA of the CHIA is approximately 73,000 acres and extends from the Patmos Ridge on the east side to the Price River on the west side. The large area of land from the base of the Book Cliffs to the Price River will not be affected by mining activity but was included in the CIA because nearby waterways that form part of the CIA boundary are included in the CHIA (DOGM 2007).

Cumulative impacts to groundwater resources with the addition of the proposed lease modification areas to the existing Lila Canyon Mine would occur as the result of the anticipated increase of 2 to 3 years to the life of the Mine. Any potential impacts to groundwater resources from mining-related subsidence would be mitigated by characteristics of the geologic formations in the proposed lease modification areas. Surface water and groundwater monitoring and subsidence monitoring would continue per permit conditions.

There would be no cumulative effects to surface water resources in the CHIA from mining-related subsidence or from mine dewatering other than the continuation of potential for discharge during the additional 2 to 3 years of mining. Discharge monitoring would continue.

According to the Lila Canyon MRP, “Waddell et al. (1986) conclude that the perched nature of the upper zone formations protects them from the influence of dewatering of the coal-bearing zone unless the upper zone is influenced by subsidence” (DOGM 2010). Mining-related subsidence is not likely to affect the shallow groundwater given the depth of cover in the proposed lease modification areas, “as the strains from subsidence are not expected to reach the level of the upper groundwater zone” (DOGM 2010).

Groundwater in saturated zones of the Blackhawk Formation is isolated and relatively immobile due to surrounding impermeable layers and extremely low hydraulic conductivity (DOGM 2010). The average hydraulic conductivity for the Blackhawk Sandstone (3.0×10^{-6} centimeter per second [cm/sec] or 0.01 inch per day) was used to estimate the groundwater travel time in this formation and determined it would take 1,736 years for groundwater to travel 1 mile. Additionally, “the water encountered and used underground would not reach the Colorado Drainage in any reasonable time, if ever, and thus water consumed underground cannot negatively affect the Colorado River Basin” (DOGM 2010). Therefore, the proposed lease modification areas would extend the duration of mining activity in the CIA but would not result in cumulative impacts to groundwater and surface water resources when added to other past, present, and reasonably foreseeable future actions in the CIA.

3.5 Geology, Minerals, and Energy Production

The analysis area for potential direct, indirect, and cumulative effects on geology is the LMA areas. The analysis area for minerals and energy production is Emery and Carbon Counties as the data are summarized by each county. Leasing for oil and gas or other mineral resources, however, would only be affected within the LMA areas. Energy development as related to GHG and climate effects is discussed on local, regional, and national scales (see Appendix D). The BLM’s PFO RMP objectives for minerals and energy resources are to maintain coal leasing, exploration, and development; maintain opportunities to lease other solid minerals; and manage oil and gas leasing all while minimizing impacts to other resource values (BLM 2008).

3.5.1 Affected Environment

Physiographically, the Lila Canyon Mine is included in the Colorado Plateau province. The Unita Basin lies to the northeast, the San Rafael Swell to the southwest, and the Wasatch Plateau to the west. The Lila Canyon Mine is situated in the western Book Cliffs, an escarpment that extends east and south from Castle Gate to Green River, Utah, then east to Grand Junction, Colorado, a distance of 180 miles (DOGM 2007).

The coal resources of the Book Cliffs coal field are exposed in the south-to-southwest–facing Book Cliffs that form the southern margin of the Roan Plateau. The coal beds of economic importance in the Book Cliffs coal field are Upper Cretaceous in age and are confined to the Blackhawk Formation of the Mesaverde Group. The Mesaverde Group in the Lila Canyon Mine vicinity consist of three formations which are, in ascending order, the Blackhawk Formation, Castlegate Sandstone, and the Price River Formation. The Blackhawk Formation is a mixed marine and continental environment. The Castlegate Sandstone and the Price River Formation were formed in a continental environment. The bluish-gray shale of the Mancos Shale crops out below the base of the Book Cliffs and in places is capped by pediment deposits from the Pleistocene. Sandstone beds of the Blackhawk Formation crop out in steep and precipitous cliffs and ledges above the Mancos Shale.

The Mesaverde Group's Blackhawk Formation contains the important coal-bearing zones within the region. Two coal seams, the Upper Sunnyside and Lower Sunnyside seams, are located in the Blackhawk Formation. The Sunnyside Coal Zone outcrops near the top of the Book Cliffs escarpment and dips eastward at 7–8 degrees between N75°E and N90°E. Because the surface topography rises in the direction of the dip, the overburden thickness above the Sunnyside Coal Zone increases rapidly to the east. Overburden cover in the LMA areas ranges from around 1,500 feet in the southeastern part of U-0126947 to about 3,500 feet at the eastern extent of the LMA areas.

A major system of transverse, easterly trending normal faults, radial from the San Rafael Swell, have been mapped in the Lila Canyon Mine area. Vertical displacements of the faults range from 15 feet to more than 275 feet with displacement diminishing toward the east, in the vicinity of the LMAs. The Central Graben Fault is near the southern boundary of the existing Lila Canyon Mine and is mapped as extending eastward into the LMA area. The Entry Fault, to the north of the Central Graben Fault, is also mapped as extending into the LMA area. Unmapped minor faults may also be present. The geologic fault pattern is that of a series of horsts and grabens. (DOGM 2007).

The LMA areas are open to oil and gas leasing subject to minor constraints (timing limitations, controlled surface use, lease notices) (BLM 2008: Map R-25). However, there are no existing federal oil and gas leases in the LMA areas. The PFO RMP Management Decision MLE-4 states that the BLM must identify the priority energy resource in conflict areas to promote safe and efficient extraction of energy resources (BLM 2008).

DOGM oil and gas production data for the last 5 years show that as of September 2019, there were no APDs in Emery County in 2019, there was one APD in 2018, there was one APD in 2017, and there were no APDs in 2016 and 2015 (DOGM 2019a). During that same period in Carbon County, there were a total of 36 APDs. Additionally, there have been four APDs on federal lands in Emery County with helium as the objective.

Oil production in Emery County was 608 barrels (BBL) or less each year from 2015 to 2019. In Carbon County, oil production ranged from nearly 28,000 BBL in 2019 (partial year) to nearly 88,000 BBL in 2015. Oil and gas production were at least four times higher in Carbon County than in Emery County for each year shown in Table 3-20. Oil and gas production in the region is described in Appendix D.

Table 3-20. Emery and Carbon Counties Oil and Gas Production 2015–2019

	County	2015	2016	2017	2018	2019*
Oil (in BBL)	Emery	184	608	571	347	157
	Carbon	87,968	79,247	57,792	47,386	27,868
Natural gas (in MCF) (includes coalbed CH_4)	Emery	8,630,719	8,143,306	7,466,663	6,952,008	3,966,722
	Carbon	69,382,875	55,684,110	46,883,601	42,229,697	24,889,453
Coalbed CH_4	Emery	6,533,904	6,058,638	5,553,126	5,211,245	2,026,546
	Carbon	32,160,461	29,959,808	27,517,370	25,661,224	9,980,625

Source: DOGM (2019a).

Note: 1 BBL = 42 U.S. gallons; 1 MCF = 1,000 cubic feet.

* 2019 data as of October 2, 2019, through last complete reporting period.

There are no active mineral mines in or near the LMA areas. According to DOGM records, the closest active mineral mines are for clay, gypsum, or humic shale, and these are in the western part of Emery County (DOGM 2019b), approximately 50 miles southwest of the Lila Canyon Mine. There are no gravel extraction pits in the LMA areas or contiguous to them. Within approximately 10 miles of the LMA areas there are two permitted gravel pits, one on the Lila Canyon Mine road 3 miles west of the mine entrance and another approximately 10 miles north-northwest.

3.5.2 Environmental Impacts – Alternative A: No Action

Under the No Action alternative, the BLM would not approve UEI's application for federal coal reserves on approximately 1,272.64 acres (317.84 acres added to lease UTU-014218 and 954.80 acres added to lease UTU-0126947) and the federal coal resources contained in the two lease modifications would not be mined. The coal reserves in the lease modifications would most likely be permanently bypassed. The 1,272.64-acre LMA area would continue to be available for oil and gas leasing.

3.5.2.1 Cumulative Effects

There are no existing oil and gas leases or other mineral resource leases in the LMA areas. Ongoing oil and gas production in Carbon and Emery Counties (see Table 3-20) would be expected to continue based on economics and demand. The availability of the LBA area for oil and gas leasing would add 4,231.40 acres to the areas in Emery and Carbon Counties currently available for oil and gas leasing. Present mineral or coal mining activities in Emery and Carbon Counties (see Appendix C) would be expected to continue. Because the LMA areas would not be leased under the No Action alternative, there would be no impacts to geology, minerals, or energy production from mining in the LMAs. Therefore, there would be no cumulative impacts to geology, minerals, and energy production under the No Action alternative.

3.5.3 Environmental Impacts – Alternative B: Proposed Action

Under the Proposed Action, all of the economically mineable coal would be removed from the LMA areas. There would be no other impacts to the tract geology other than the areas of subsidence above the mined-out coal seam and associated potential interruptions to stratigraphy. Oil and gas exploration and development, as well as other mineral resource development, would not be feasible while active mining is ongoing. Therefore, the LMA areas would be unavailable for oil and gas leasing and other mineral resources development during the 2 to 3 years of mining in the LMAs. Based on the current lack of non-coal mineral activity in the LMA areas, this would have minimal impact upon mineral resource development in Emery County during the life of the mine. There would be no impact to the development viability of gravel extraction pits near the LMA areas.

Oil and gas development is presently not occurring in the LMA areas, and production is considerably lower in Emery County as compared to Carbon County (see Table 3-20). Based on this, the loss in availability of the LMA areas for oil and gas development would have minimal impact on the overall development of oil and gas resources in the region during the life of the mine. Once mining operations and reclamation are completed, the LMA areas would again be available for oil and gas leasing.

3.5.3.1 Cumulative Effects

There are no existing oil and gas leases or other mineral resources leases in the LMA areas or in this part of Emery County. Under the conceptual mine plan, the mining of coal in the LMA areas, in addition to the proposed Williams Draw LBA (if offered and leased), SITLA leases, and existing Lila Canyon Mine, would not be likely to change the currently permitted not-to-exceed production level of 4.5 million TPY. The total 2019 coal production in Carbon and Emery Counties was 9,734,000 tons (Table C-1); the Lila Canyon Mine permitted not-to-exceed production level is 46% of this total 2019 coal production.

The future addition of mining in the proposed Walker Flat coal tract may add up to 2 million tons per year, if offered and leased. The economically mineable coal would be removed from these tracts and unavailable for future leasing. Other than coal extraction, there would be no cumulative effects to geology other than potential subsidence of layers above the mined coal seams and associated potential interruptions to stratigraphy (which would not impact future oil and/or gas development due to their relative stratigraphic location in the geologic column).

Restrictions on oil and gas activity or mineral exploration or production would be implemented in all areas in Utah including the LMA areas (if leased) leased for coal development. The cumulative impacts to minerals and oil and energy activity would be a delay in the availability for such exploration or development in all areas leased for coal development for the duration of that coal development. Mineral mining in other areas of Carbon and Emery Counties (see Appendix C) would be expected to continue.

3.6 Colorado River Endangered Fish

The analysis area for potential direct, indirect, and cumulative effects on Colorado River endangered fish is the 50-km near-field air quality modeling analysis area described in Section 3.2. This area was chosen because there is no perennial surface water pathway between the LMA areas and the Colorado River system. The potential pathway for effects to fish is atmospheric dry deposition on the land or water surface. Mercury and selenium are contaminants of concern for fish in the Upper Colorado River basin. Both of these contaminants are emitted from coal-fired power plants and both elicit toxic effects at concentrations frequently observed in the environment; however, when they co-occur they can interact in complex ways, including selenium potentially ameliorating some mercury toxicity in fish (Day et al. 2020). Four species of endangered fish—the Colorado pikeminnow (*Ptychocheilus lucius*), razorback sucker (*Xyrauchen texanus*), humpback chub (*Gila cypha*), and bonytail (*Gila elegans*)— live in the

Colorado River basin and nowhere else. These fish are threatened by predation and competition from non-native fish species, and by habitat loss and modification. The Colorado River endangered fish are described in Appendix E (SWCA 2020).

3.6.1 Affected Environment

There are no perennial waters in the LMA areas (see Section 3.4). A stretch of the Price River, which flows into the Green River, and a stretch of the Green River are within the 50-km analysis area. The Green River provides critical habitat for the Colorado River endangered fish. A recent study shows elevated levels of mercury and selenium in tissue samples of some Upper Colorado River fish (see Appendix E).

The Hunter and Huntington Power Plants are regulated by the DAQ and overseen by the EPA; they have operated since the 1970s emitting mercury and other trace elements such as arsenic, lead, and selenium. Emissions controls since 2011 for some elements have reduced emissions to the atmosphere. Mercury emissions from the Hunter and Huntington Power Plants are recently estimated to contribute less than 1% of the total deposition in the local airshed and river basins. Additional background information is provided in Appendix E.

3.6.2 Environmental Impacts – Alternative A: No Action

Under the No Action alternative, the Hunter and Huntington Power Plants would continue operating as permitted. There would be no direct effects to critical habitats in the analysis area or to Colorado River endangered fish from the operation of the Lila Canyon Mine. Trace elements from coal combustion will continue to be deposited on land and water, with the likelihood that certain elements will accumulate over time to levels that may indirectly cause harmful effects to some fish individuals.

3.6.2.1 Cumulative Effects

The cumulative effects of No Action would be similar to the effects of No Action, with the potential cumulative addition of regional and global atmospheric sources of contaminants to the Colorado River system.

3.6.3 Environmental Impacts – Alternative B: Proposed Action

There would be no direct effects to Colorado River endangered fish or their critical habitats as a result of the Proposed Action. The indirect effects of the combustion of coal from the LMAs would contribute minimally to overall mercury and selenium deposition in the analysis area (See Appendix E). While some Colorado pikeminnow individuals are likely experiencing low-level harmful effects from existing mercury in the system, the additional amount of mercury from the indirect effects of coal combustion from the LMAs would not be likely to measurably reduce population numbers, reproduction, or constrain Colorado pikeminnow distribution. The relative contribution of mercury is assumed to be a very small percentage of the total mercury that has been and will continue to be deposited in the analysis area. Indirect effects from the implementation of the Proposed Action may affect but are not likely to adversely affect the Colorado River endangered fish populations or their critical habitat (see Appendix E).

3.6.3.1 Cumulative Effects

The cumulative effects from implementation of the Proposed Action would be similar to the effects described for the Proposed Action because the combustion of the coal from the LMAs would contribute minimally to overall mercury deposition in the analysis area, and because the existing Hunter and Huntington Power Plants are permitted to release certain levels of contaminants into the atmosphere. The combustion of coal from the LMAs would not increase these allowable levels of contaminants. National standards are in place for coal-fired power plants to prevent about 90% of the mercury in coal from being emitted to the air. No new coal-fired power plants are proposed for construction that would add cumulatively to the mercury deposition on the analysis area. Hunter and Huntington Power Plants would continue to operate as permitted and would likely combust additional coal from a different source if the coal from the LMA areas was unavailable.

CHAPTER 4. CONSULTATION AND COORDINATION AND PUBLIC INVOLVEMENT

4.1 Tribes, Individuals, Organizations, or Agencies Consulted

As described above in Chapter 1, the BLM listed the Proposed Action on its ePlanning website on May 14, 2018. The BLM initiated tribal consultation in October 2018 with tribal representatives. Tribal consultation letters were sent on October 12, 2018, to 16 tribal governments with known interest and association with the region. A response letter dated October 18, 2018, was received from the Hopi Tribe requesting copies of any cultural resources reports or treatment plans should adverse effects be anticipated as a result of the development of the proposed lease modification areas.

The Office of Surface Mining Reclamation and Enforcement participated in this EA process as a cooperating agency. The U.S. Fish and Wildlife Service participated in informal consultation under Section 7 of the Endangered Species Act which concluded in concurrence on effects to Mexican spotted owl (*Strix occidentalis lucida*) and its designated critical habitat, and Colorado pikeminnow, razorback sucker, humpback chub, and bonytail (collectively referred to as Colorado River fishes), and their designated critical habitat (see Appendix E).

4.2 Public Involvement

Public and agency comments were sought via the BLM National NEPA Register (ePlanning) during the draft EA review period. The EA was open for public comment from April 24, 2020, to June 8, 2020. During the public comment period, there were 1,409 total submissions received via email and on ePlanning. Of this total, 1,318 were forms, two letters were from non-government organizations (NGOs), and one letter was from Emery County. A total of three submissions were in support of the project. Substantive comments were evaluated; some comments resulted in changes to the EA. The summarized comments and BLM responses are provided in Appendix F.

4.3 List of Preparers

The list of preparers is found in Appendix G.

APPENDIX A

BLM Interdisciplinary Team Checklist

APPENDIX A: INTERDISCIPLINARY TEAM CHECKLIST

INTERDISCIPLINARY TEAM CHECKLIST

RESOURCES AND ISSUES CONSIDERED (INCLUDES SUPPLEMENTAL AUTHORITIES APPENDIX 1 H-1790-1)

Project Title: Lila Canyon Mine Lease Modifications

NEPA Log Number: DOI-BLM-UT-G020-2018-0039-EA

File/Serial Number: U-014218(M), U-0126947(M)

Project Leader: M Glasson

Determination of STAFF: (Choose one of the following abbreviated options for the left column)

NP = not present in the area impacted by the proposed or alternative actions

NI = present, but not affected to a degree that detailed analysis is required

PI = present with potential for relevant impact that need to be analyzed in detail in the EA

NC = (DNAs only) actions and impacts not changed from those disclosed in the existing NEPA documents cited in Section D of the DNA form. The Rationale column may include NI and NP discussions.

Determination	Resource/Issue	Rationale for Determination	Signature	Date
PI	Air Quality & Greenhouse Gas Emissions	Impacts from this proposed lease modification could extend the life of the Mine by 2 to 3 years, resulting in continued operational emissions (including GHG) from equipment operation. In addition, downstream use of the coal would result in emissions. The EA will assess the effects of operational and downstream emissions.	Stephanie Howard	5/25/2018
NP	BLM Outstanding Natural Areas	There are no BLM Natural Areas in the proposed lease modification areas per review of the RMP and GIS.	Blake Baker	2/21/2020

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NI	Cultural: Archaeological Resources	The Proposed Action is determined to be a federal undertaking, per Title 36 CFR Chapter VIII Part 800.16(y). In accordance with Title 36 CFR 800.3(a)(1), the agency has determined this undertaking is a type of activity that does not have the potential to cause effects on historic properties, assuming such historic properties are present. Therefore, the agency has no further obligations under Section 106 of the National Historic Preservation Act regarding the proposed lease modifications. The BLM is applying Waiver #7 to the Proposed Action: the nature of the proposed subsurface action is such that no impact to significant cultural resources is expected. In accordance with Title 36 Code of Federal Regulations Chapter VIII Part 800, the BLM will not approve any ground disturbing activities that have the potential to cause effects on historic properties until the areas of potential effect have been analyzed and processed according to Section 106 of the National Historic Preservation Act and related authorities. The modification of a lease does not authorize any surface disturbing activities, including, but not limited to, development of surface facilities, vents, portals, or planned subsidence with the potential to effect ground surface. The BLM may require modifications to facility development proposals to protect historic properties or disapprove any activity that is likely to result in adverse effect to historic properties that cannot be successfully avoided, minimized, or mitigated.	Natalie Fewings	7/11/2018
NI	Cultural: Native American Religious Concerns	Tribal consultation letters were sent to 16 tribal governments with known interest and association with the region on 10/12/18. A response letter dated October 18, 2018, was received from the Hopi Tribe requesting copies of any cultural resources reports or treatment plans should adverse effects be anticipated as a result of the development of the proposed lease modification areas. The agency decided this lease modification does not have the potential to effect historic properties, should historic properties exist in the area (36 CFR 800.3(a)(1), No other responses were received.	Natalie Fewings	10/20/2020
NP	Designated Areas: National Historic Trails	There are no National Historic Trails in the proposed lease modification areas per review of the RMP and GIS.	Blake Baker	2/21/2020
NP	Designated Areas: Areas of Critical Environmental Concern	There are no Areas of Critical Environmental Concern in the proposed lease modification areas per review of the RMP and GIS.	Blake Baker	2/21/2020
NP	Designated Areas: Wild and Scenic Rivers	There are no Wild and Scenic Rivers in the proposed lease modification areas per review of the RMP and GIS.	Blake Baker	2/21/2020
NP	Designated Areas: WSA/Wilderness	There are no Designated Areas, Wilderness Study Areas, or Wilderness Areas in the proposed lease modification areas per review of the RMP and GIS. Portions of the lease modification areas were not mapped at that time due to RMP Decision MLE-3, which removes wilderness study areas (WSAs) from consideration for coal leasing. At the time the LMA was submitted to BLM, the Turtle Canyon WSA extended into the lease modification areas. With enactment on March 12, 2019, of the John D. Dingell, Jr. Conservation, Management, and Recreation Act (P.L. 116-9) (the Act) (see Section 1.6), there is no longer a Turtle Canyon WSA. The Act designated a new Turtle Canyon Wilderness Area which is not contiguous to and does not encumber the proposed lease modification areas. The proposed lease modification is outside of Turtle Canyon Wilderness Area.	Blake Baker	10/20/2020
NP	Environmental Justice	No low income or minority communities exist in or near the proposed lease modification areas. Therefore, no disproportionate impacts will occur.	Stephanie Howard	5/25/2018

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NP	Farmlands (prime/unique)	According the NRCS soil survey and knowledge of the area, there are no prime/unique farmlands above the proposed lease modification areas. The Proposed Action will occur underground and there are no prime/unique farmlands that would be affected by proposed lease modification or subsequent mining.	Stephanie Bauer	7/2/2018
NP	Fuels/Fire Management	There are no current impacts to Fuels/Fire Management (both direct and indirect) at this time. Future impacts would be negligible.	Stuart Bedke	4/5/2018
PI	Geology / Minerals / Energy Production	This proposal is a beneficial use of the mineral at the site. It is consistent with the goals and objectives of the BLM Price Field Office as documented in the PFO Resource Management Plan. The sub-surface extraction of coal would not remove any surface deposits. There are no federal oil & gas leases in the project area. The project area is open to oil & gas leasing subject to minor constraints. It would not be feasible for exploration or production of oil and gas while active mining is ongoing.	Mike Glasson	10/14/2020
NI	Invasive Plants / Noxious Weeds / Vegetation	The spread and introduction of invasive species/noxious weeds are not anticipated to occur because of the Proposed Action. The proposed lease modification areas are underground, and no subsidence is expected, therefore no surface disturbance is expected.	Stephanie Bauer	7/2/2018
NI	Lands/Access	With no surface use or disturbance, lands and access will not be impacted. A review of LR2000 and the Master Title Plats showed that the Proposed Action is compatible with the existing land use and authorized rights-of-way. There are no conflicts with other land use authorizations.	Connie Leschin	4/9/2018
NI	Lands with Wilderness Characteristics	The proposed project area overlaps the Turtle Canyon LWC unit. However, with no surface use or disturbance, Lands with Wilderness Characteristics will not be impacted.	Blake Baker	2/21/2020
NI	Livestock Grazing	With no surface disturbance, livestock grazing will not be impacted.	Jason Carlile	4/23/2018
NI	Paleontology	While there is some potential for vertebrate fossils being present, with no surface disturbance there is no risk of damage to them.	Michael Leschin	4/10/2018
NI	Plants: BLM Sensitive	Suitable or occupied habitat for the following UT BLM Sensitive plant species has been previously documented or is expected to occur within Emery County, UT. *Alicella tenuis, Astragalus pubentissimus peabodianus, Camissonia bolanderi, Cryptantha creutzfeldtii, Eriogonum corybosum smithii, Erigeron maguirei, Lygodesmia grandiflora entrada, Mentzelia multicaulis var librina, Oreoxis trotteri, Psorothamnus polydenius jonesii, Sphaeralcea psoraloides, Talinum thompsonii* Analysis of soils, geology, elevation, and ecological systems, overlying the proposed lease modification areas indicates potential that suitable habitat for *Mentzelia multicaulis var librina* occurs there. There are possible exposures of suitable geology, Price River Formations, and it is close to the typical elevation. Although suitable habitat for this plant occurs, there would be no impacts to habitat because no surface disturbance is proposed or anticipated. Based on the depth of the coal seam from 2,000 to 3,000 feet, no surface expression of subsidence is anticipated. For the other species, there is not suitable geology or elevation within the proposed lease modification areas, and there are no records of occurrences. Because suitable habitat is not present, these species are unlikely to be present. For these reasons and because no surface disturbance is proposed or anticipated, a detailed analysis of BLM sensitive plants is not required.	Dana Truman	08/24/2018

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NI	Plants: Threatened, Endangered, Proposed, or Candidate	Several Federally listed plant species occur within Emery County. *Cycladenia jonesii (humilis)* *Pediocactus despainii* *Pediocactus winkleri* *Schoenocrambe barnebyi* *Sclerocactus glaucus* *Sclerocactus wrightiae* *Townsendia aprica* Analysis of soils, geology, elevation, and ecological systems, within the proposed lease modification areas indicates that suitable habitat for the identified species is not present. Since suitable habitat is not present, these species are unlikely to be present. Because these species are unlikely to be present and no surface disturbance is proposed or anticipated, detailed analysis of threatened, endangered, proposed, or candidate plants is not required.	Dana Truman	5/16/2018
NI	Rangeland Health Standards	Rangeland Health standards reflects hydrology, soils, and biotic components of the rangeland. No impacts to soils, hydrology or biology are anticipated due to lack of surface disturbance in the proposed lease modification areas. Impacts to these resources, if any, will be addressed in their respective sections.	Jason Carlile	4/23/2018
NI	Recreation	The Proposed Action is in an Extensive Recreation Management Area (ERMA) where recreation opportunities are limited, and explicit recreation management is not required. The ERMA receives only custodial management for recreation opportunities. With no surface disturbance, no impacts to this resource are anticipated.	Blake Baker	2/21/2020
PI	Socio-Economics	Issuance of the proposed lease modifications could extend the life of the Lila Canyon Mine by 3+ years. The analysis of extension of operations will be assessed, including the effects upon the Emery and Carbon County economies.	Stephanie Howard	5/25/2018
NI	Soils: Physical / Biological	There is no new surface disturbance proposed or anticipated. Based on the depth of the coal seam (from 2,000 to 3,000 feet), no surface expression of subsidence is anticipated. A color infrared aerial photography study is conducted periodically as part of DOGM monitoring commitments under the Lila Canyon Mine permit approval. The study monitors impacts of subsidence on surface vegetation communities. The baseline data were gathered in 2011, and the study was repeated in 2016 per the 5-year interval requirement. No differences were observed between 2011 and 2016, suggesting that if subsidence occurred, it has had little impact to the plant and soil communities at the Lila Canyon Mine. Therefore, detailed analysis is not required.	Stephanie Bauer	1/4/2021
NI	Vegetation: Vegetation Excluding USFW Designated Species and BLM Sensitive Species	There is no new surface disturbance proposed or anticipated. Based on the depth of the coal seam (from 2,000 to 3,000 feet), no surface expression of subsidence is anticipated. A color infrared aerial photography study is conducted periodically as part of DOGM monitoring commitments under the Lila Canyon Mine permit approval. The study monitors impacts of subsidence on surface vegetation communities. The baseline data were gathered in 2011, and the study was repeated in 2016 per the 5-year interval requirement. No differences were observed between 2011 and 2016, suggesting that if subsidence occurred, it has had little impact to the plant and soil communities at the Lila Canyon Mine. Therefore, detailed analysis is not required.	Stephanie Bauer	1/4/2021

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NI	Visual Resources	The proposed lease modification areas are within a VRM Class I. The Class I management objective is to preserve the existing character of the landscape. The level of change to the characteristic landscape should be very low and must not attract attention. Since no surface disturbance is proposed or anticipated, there will be no impact to visual resources and the existing character of the landscape will be maintained. Detailed analysis of visual resources is not required.	Blake Baker	2/21/2020
NI	Wastes (hazardous/solid)	No chemicals subject to reporting under SARA Title III will be used, produced, stored, transported, or disposed of annually in association with the Proposed Action. Furthermore, no extremely hazardous substances, as defined in 40 CFR 355, in threshold planning quantities, will be used, produced, stored, transported, or disposed of in association with the Proposed Action. Trash would be confined in a covered container and disposed of in an approved landfill. No burning of any waste will occur due to this project. Human waste will be disposed of in an appropriate manner in an approved sewage treatment center.	Bill Civish	5/11/2018
PI	Water: Groundwater Quality	Spatial analysis of the proposed lease modification application and proposed lease modification areas indicates no interaction with subsurface horizons containing usable water. The proposed mining of the proposed lease modification areas is approximately 2,500 feet below the ground surface. Additional groundwater information will be reviewed to determine the potential for impacts.	Rebecca Anderson	10/26/2018
NI	Water: Hydrologic Conditions (stormwater)	The proposed mining associated with the proposed lease modification areas would not alter the topography; therefore, detailed analysis is not required.	Jerrad Goodell	12/10/2020
NP	Water: Municipal Watershed / Drinking Water Source Protection	GIS review indicate no drinking water source areas or beneficial uses of watersheds from UDEQ-DWQ.	Jerrad Goodell	12/10/2020
NI	Water: Streams, Riparian Wetlands, Floodplains	There are no perennial water resources in the LMA areas or in the Lila Canyon Mine permit area. The LMAs and the SCT are in the Price River Basin; the Hunter and Huntington Power Plants are in the San Rafael River Basin; both of these rivers are tributary to the Green River, which joins the Colorado River. Any mine water discharges are expected to infiltrate within approximately 3.4 miles of the point of discharge and would not reach the Price River, about 12.7 miles from the LMA. Additionally, due to the depth of the mining operation, and lack of surface disturbance, no impacts to these resources are expected. Detailed analysis is not required.	Jerrad Goodell	12/10/2020
PI	Water: Surface Water Quality	There are 2 spring systems in the lease modification areas: L-8-G and L-9-G (Pine Spring). The interaction of mine activities with the springs and intermittent stream channel needs to be analyzed in detail to determine impacts.	Jerrad Goodell	10/23/2020
NI	Water: Water Rights	Water rights proximate to the LMA areas are 91-2539 (owned by the BLM), 91-808, and 91-2538 (a water right used for stock watering owned by the State of Utah). Mining of the proposed lease modification areas would not affect any water rights or the ability to use any water rights because of the depth of mining and lack of surface disturbance. With 1,500 to 2,100 feet of cover above mined areas, mining-related subsidence is not anticipated to impact surface water or shallow groundwater. Detailed analysis is not required.	Jerrad Goodell	12/10/2020
NP	Water: Waters of the U.S.	GIS review indicates no navigable waters or waters of the U.S. are within the proposed lease modification areas. Detailed analysis is not required.	Jerrad Goodell	12/10/2020

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NP	Wild Horses and Burros	The proposed lease modification areas are not within a Wild Horse or Burro Herd Management Area. Detailed analysis is not required.	Mike Tweddell	4/2/2018
NI	Wildlife: Migratory Birds (including raptors)	Migratory birds could use the area above the proposed lease modification areas foraging and nesting. There are known golden eagle nests within 3 miles of the proposed lease modification areas, but not within surface habitat overlying the areas. Due to the depth of the mining operation, and lack of surface disturbance, no impacts to bird populations or their habitat is expected. Detailed analysis is not required.	Dana Truman	5/16/2018
PI	Wildlife: Fish (designated or non-designated)	**Direct Effects**: The LMAs and the SCT are in the Price River Basin; the Hunter and Huntington Power Plants are in the San Rafael River Basin; both of these rivers are tributarys to the Green River, which joins the Colorado River. The Colorado River system is home to several non-designated fish species and four listed under the Endangered Species Act: Bonytail (*Gila elegans*) - endangered; Colorado pikeminnow (*Ptychocheilus lucius*) - endangered; humpback chub (*Gila cypha*) - proposed for reclassification from endangered to threatened; and razorback sucker (*Xyrauchen texanus*) - endangered. Colorado River depletions are monitored under the Colorado River Endangered Fish Recovery Program. Any mine water discharges are expected to infiltrate within approximately 3.4 miles of the point of discharge and would not reach the Price River, approximately 12.7 miles from the LMA. As part of their DOGM annual permit report, the Lila Canyon Mine is required to submit a depletion estimate under the Colorado River Endangered Fish Recovery Program. Consumptive water use calculations for the past 4 years (2016–2019 DOGM annual report years) range from 0.062 to 0.066 cfs. There are no perennial water resources in the LMA areas or in the Lila Canyon Mine permit area. There are no fish species (including their associated habitats) within or near the LMA areas or the Lila Canyon Mine permit area per GIS mapping of streams and sensitive fish species occurrences, therefore direct impacts to designated and non-designated fish species is not expected. **Indirect Effects:** Mercury and selenium deposition within the Colorado river watershed from coal combustion is possible. This could lead to bioaccumulation and potentially impact fish habitat and populations; these impacts are discussed in detail in Appendix E. The BLM conducted informal consultation with the U.S. Fish and Wildlife Service to assess the potential for effects of the Proposed Action on the populations of Colorado River federally- listed fishes or their habitats. This concluded in USFWS concurrence with the finding of “may affect but not likely to adversely affect” the four endangered fish species in the Colorado River and their critical habitat; the concurrence letter is included as supporting documentation to this EA on ePlanning.	Jerrad Goodell	12/10/2020
NI	Wildlife: Non-USFWS Designated	There are no UDWR designated crucial habitats for big game within the proposed lease modification areas. Mining activities have been occurring on the adjacent leases for the past several years. There have been no measurable changes to the wildlife populations. The wildlife guzzlers and habitat treatments for the big horn sheep have been effective mitigation for the past mining activities. Due to the depth of the mining operation and lack of surface disturbance, no impacts are expected to the surface habitat for general wildlife. Detailed analysis is not required.	Dana Truman	5/16/2018

Determination	Resource/Issue	Rationale for Determination	Signature	Date
NI	Wildlife: BLM Sensitive	Several BLM sensitive species could use the proposed lease modification areas for foraging, resting, or nesting. Mining on the adjacent leases has been occurring without measurable impacts to wildlife. The springs have been and will be consistently monitored for change in quantity and quality. According to the Approved Resource Management Plan Amendments (BLM 2015), designated sage-grouse GHMA habitat is approximately 7 miles away. Due to the existing monitoring and response plan and the expected lack of surface disturbance, no impacts to sensitive wildlife populations or their habitat is expected. Detailed analysis is not required.	Dana Truman	5/16/2018
NI	Wildlife: Threatened, Endangered, Proposed or Candidate	Suitable or occupied habitat for the following Federally listed species has been previously documented or is expected to occur within Emery County (IPaC5/16/18). California condor (*Gymnogyps californianus*) [CACO] -Would be an unlikely visitor to the proposed lease modification areas due to the elevation, and other habitat considerations. Mexican spotted owl (*Strix occidentalis lucida*) [MSO]–Designated critical occurs within the proposed lease modification areas Southwestern willow flycatcher (*Empidonax traillii extimus*) [SWFL]– Designated critical habitat greater than 30 miles away. Yellow billed cuckoo (*Coccyzus americanus*) [YBCC] – Suitable habitat greater than 10 miles away associated with the Green River or Price River. Analysis of elevation and habitat requirements, overlying the proposed lease modification areas indicates that suitable habitat for the CACO, SWFL, and YBCC is not present. Since suitable habitat is not present, these species are unlikely to be present in habitat overlying the proposed lease modification areas. Since these species are unlikely to be present and no surface disturbance is proposed or anticipated, a no effect determination was made and detailed analysis is not required. The Lila Canyon Lease Modifications overlap the CP-15 unit of Designated Critical Habitat for the MSO. There are approximately 186,360 acres within the CP-15 unit. The Lila Canyon Lease modification is on the southern edge of the habitat unit and overlaps 166 acres or less than 1 percent of critical habitat. No surface disturbance is proposed or anticipated and the mining activities would be through the existing portals that are well outside the critical habitat. Due to the lack of surface disturbance, and no change in the mining activities at the surface, there would be no impact to the designated Critical Habitat for MSO or effects to the physical or biological features that are essential to the conservation of the species. A no effect determination was made and detailed analysis is not required.	Dana Truman	8/24/2018
NI	Woodlands/ Forestry	Woodlands/Forestry occur on the surface within the proposed lease modification areas. However, no subsidence is anticipated. Detailed analysis is not required.	Stephanie Bauer	7/2/2018

FINAL REVIEWS

Reviewer Title	Signature	Date	Comments
Environmental Coordinator	JOSEPH RODARME Digitally signed by JOSEPH RODARME Date: 2021.01.04 16:25:36 -07'00'		
Authorized Officer	CHRISTOPHER CONRAD Digitally signed by CHRISTOPHER CONRAD Date: 2021.01.04 19:15:51 -07'00'		

APPENDIX B

Lease Stipulations

SPECIAL STIPULATIONS FOR UTU-014218 MODIFIED COAL LEASE

1. In accordance with Sec. 523(b) of the “Surface Mining Control and Reclamation Act of 1977,” surface mining and reclamation operations conducted on this lease are to conform with the requirements of this act and are subject to compliance with Office of Surface Mining regulations, or as applicable the Utah program approved under the cooperative agreement in accordance with sec. 523(c). The United States Government does not warrant that the entire tract will be susceptible to mining.

2. Before undertaking activities that may disturb the surface of previously undisturbed leased lands, the lessee may be required to conduct a cultural resource inventory and a paleontological appraisal of the areas to be disturbed. These studies shall be conducted by qualified professional cultural resource specialists or qualified paleontologists, as appropriate, and a report prepared itemizing the findings. A plan will then be submitted making recommendations for the protection of, or measures to be taken to mitigate impacts for identified cultural or paleontological resources.

If cultural resources or paleontological remains (fossils) of significant scientific interest are discovered during operations under this lease, the lessee prior to disturbance shall, immediately bring them to the attention of the Authorized Officer. Paleontological remains of significant scientific interest do not include leaves, ferns, or dinosaur tracks commonly encountered during underground mining operations.

The cost of conducting the inventory, preparing reports, and carrying out mitigating measures shall be borne by the lessee.

3. If there is reason to believe that Threatened or Endangered (T&E) species of plants or animals, or migratory bird species of high Federal interest occur in the area, the Lessee shall be required to conduct an intensive field inventory of the area to be disturbed and/or impacted. The inventory shall be conducted by a qualified specialist and a report of findings will be prepared. A plan will be prepared making recommendations for the protection of these species or action necessary to mitigate the disturbance.

The cost of conducting the inventory, preparing reports, and carrying out mitigating measures shall be borne by the lessee.

4. Before undertaking activities that may disturb the surface of previously undisturbed leased lands, the lessee may be required to conduct a paleontological appraisal of the areas to be disturbed. The appraisal shall be conducted by a qualified paleontologist and a report prepared itemizing the findings.

A plan will then be submitted making recommendations for the protection of, or measures to be taken to mitigate impacts for identified paleontological resources.

If paleontological remains (fossils) of significant scientific interest are discovered during operations under this lease, the lessee shall immediately bring them to the attention of the authorized officer who shall evaluate, or have evaluated such discoveries and, within 5 working days, shall notify the lessee what action shall be taken with respect to such discoveries. Paleontological remains of significant scientific interest do not include leaves, ferns, or dinosaur tracts commonly encountered during underground mining.

The cost of conducting the inventory, preparing reports, and carrying out necessary protective mitigating measure shall be borne by the lessee. The cost of salvage of paleontological remains (fossils) shall be borne by the United States.

5. The Lessee shall be required to perform a study to secure adequate baseline data to quantify the existing surface resources on and adjacent to the lease area. Existing data may be used if such data are adequate for the intended purposes. The study shall be adequate to locate, quantify, and demonstrate the interrelationship of the geology, topography, surface and ground water hydrology, vegetation, and

wildlife. Baseline data will be established so that future programs of observation can be incorporated at regular intervals for comparison.

6. Powerlines used in conjunction with the mining of coal from this lease shall be constructed so as to provide adequate protection for raptors and other large birds. When feasible, powerlines will be located at least 100 yards from public roads.

7. The lessee shall provide for the suppression and control of fugitive dust on haul roads and at coal-handling and storage facilities on the lease area. The migration of road surfacing and subsurface materials into streams and water courses shall be prevented.

8. The lessee shall be required to establish a monitoring system to locate, measure, and quantify the progressive and final effects of underground mining activities on the topographic surface, underground and surface hydrology and vegetation. The monitoring system shall utilize techniques which will provide a continuing record of change over time and an analytical method for location and measurement of a number of points over the lease area. The monitoring shall incorporate and be an extension of the baseline data. The monitoring system shall be adequate to locate and quantify, and demonstrate the inter-relationship of the geology, topography, surface hydrology, vegetation, and wildlife.

9. Except at locations specifically approved by the Authorized Officer with concurrence of the surface management agency, underground mining operations shall be conducted in such a manner so as to prevent surface subsidence that would: (1) cause the creation of hazardous conditions such as potential escarpment failure and landslides, (2) cause damage to existing surface structures, and (3) damage or alter the flow of perennial streams. The lessee shall provide specific measures for the protection of escarpments and determine corrective measures to assure that hazardous conditions are not created.

10. In order to avoid surface disturbance on steep canyon slopes and to preclude the need for surface access, all surface breakouts for ventilation tunnels shall be constructed from inside the mine, except at specifically approved locations.

11. If removal of timber is required for clearing of construction sites, etc., such timber shall be removed in accordance with the regulation of the surface management agency.

12. Support facilities, structures, equipment, and similar developments will be removed from the lease area within 2 years after the final termination of use of such facilities. This provision shall apply unless the requirement of Section 10 of the lease form is applicable. Disturbed areas and those areas previously occupied by such facilities will be stabilized and rehabilitated, drainages reestablished, and the areas returned to an authorized post mining land use.

13. The Lessee at the conclusion of the mining operation, or at other times as surface disturbance related to mining may occur, will replace all damaged, disturbed, or displaced corner monuments (section corners, quarter corners, etc.) their accessories and appendages (witness trees, bearing trees, etc.), or restore them to their original condition and location, or at other locations that meet the requirements of the rectangular surveying system. This work shall be conducted at the expense of the Lessee, by BLM to the standards and guidelines found in the Manual of Surveying Instructions, U.S. Department of Interior.

14. Notwithstanding the approval of a resource recovery and protection plan (R2P2) by the BLM, lessor reserves the right to seek damages against the operator/lessee in the event (I) the operator/lessee fails to achieve maximum economic recovery [as defined at 43 CFR §3480.0-5(21)] of the recoverable coal reserves or (ii) the operator/lessee is determined to have caused a wasting of recoverable coal reserves. Damages shall be measured on the basis of the royalty that would have been payable on the wasted or un-recovered coal.

The parties recognize that under an approved R2P2, conditions may require a modification by the operator/lessee of that plan. In the event a coal bed or portion thereof is not to be mined or is rendered un-minable by the operation, the operator shall submit appropriate justification to obtain approval by the AO to leave such reserves unmined. Upon approval by the AO, such coal beds or portions thereof shall not be subject to damages as described above. Further, nothing in this section shall prevent the operator/lessee from exercising its right to relinquish all or a portion of the lease as authorized by statute and regulation.

In the event the AO determines that the R2P2 modification will not attain MER resulting from changed conditions, the AO will give proper notice to the operator/lessee as required under applicable regulations. The AO will order a new R2P2 modification if necessary, identifying additional reserves to be mined in order to attain MER. Upon a final administrative or judicial ruling upholding such an ordered modification, any reserves left un-mined (wasted) under that plan will be subject to damages as described in the first paragraph under this section.

Subject to the right to appeal hereinafter set forth, payment of the value of the royalty on such un-mined recoverable coal reserves shall become due and payable upon determination by the AO that the coal reserves have been rendered un-minable or at such time that the lessee has demonstrated an unwillingness to extract the coal.

The BLM may enforce this provision either by issuing a written decision requiring payment of the MMS demand for such royalties, or by issuing a notice of non-compliance. A decision or notice of non-compliance issued by the lessor that payment is due under this stipulation is appealable as allowed by law.

15. The lessee, at his expense, will be responsible to replace any surface water sources identified for protection, that may be lost or adversely affected by mining operations, with water from an alternate source in sufficient quantity and quality to maintain existing riparian habitat, fishery habitat, livestock and wildlife use, or other land uses (authorized by 26 CFR 251).

16. WASTE CERTIFICATION: The lessee shall provide upon abandonment and/or sealing off a mined area and prior to lease termination/relinquishment, certification to the lessor that, based upon a complete search of all the operator's records for the mine and upon their knowledge of past operations, there has been no hazardous substances per (40 CFR 302.4) or used oil as per Utah State Management Rule R-315-15, deposited within the lease, either on the surface or underground, or that all remedial action necessary has been taken to protect human health and the environment with respect to any such substances remaining on the property. The back-up documentation to be provided shall be described by the lessor prior to the first certification and shall include all documentation applicable to the Emergency Planning and Community Right-to-know Act (EPCRA, Public Law 99-499), Title III of the Superfund Amendments and Reauthorization Act of 1986 or equivalent.

17. ABANDONMENT OF EQUIPMENT: The lessee/operator is responsible for compliance with reporting regarding toxic and hazardous material and substances under Federal Law and all associated amendments and regulations for the handling such materials on the land surface and in underground mine workings.

The lessee/operator must remove mine equipment and materials not needed for continued operations, roof support and mine safety from underground workings prior to abandonment of mine sections. Exceptions can be approved by the Authorized Officer (BLM) in consultation with the surface management agency. Creation of a situation that would prevent removal of such material and by retreat or abandonment of mine sections without prior authorization would be considered noncompliance with lease terms and conditions and subject to appropriate penalties under the lease.

18. UNDERGROUND INSPECTION: All safe and accessible areas shall be inspected prior to being sealed. The lessee shall notify the Authorized Officer in writing 30 days prior to the sealing of any areas in the mine and state the reason for closure. Prior to seals being put into place, the lessee shall inspect the area and document any equipment/machinery, hazardous substances, and used oil that is to be left underground.

The purpose of this inspection will be: (1) to provide documentation for compliance with 42 U.S.C. 9620 section 120(h) and State Management Rule R-315-15, and to assure that certification will be meaningful at the time of lease relinquishment, (2) to document the inspection with a mine map showing location of equipment/machinery (model, type of fluid, amount remaining, batteries etc.) that is proposed to be left underground. In addition, these items will be photographed at the lessee's expense and shall be submitted to the Authorized Officer as part of the certification. The abandonment of any equipment/machinery shall be on a case by case basis and shall not be accomplished unless the Authorized Officer has granted a written approval.

The purpose of this inspection will be: (1) to provide documentation for compliance with 42 U.S.C. 9620 SECTION 120(h) and State Management Rule R-315-15, and to assure that certification will be meaningful at the time of lease relinquishment, (2) to document the inspection with a mine map showing location of equipment/machinery (model, type of fluid, amount remaining, batteries etc.) that is proposed to be left underground. In addition, these items will be photographed at the lessee's expense and shall be submitted to the Authorized Office as part of the certification. The abandonment of any equipment/machinery shall be on a case by case basis and shall not be accomplished unless the Authorized Officer has granted a written approval.

19. FAIR MARKET VALUE BONUS: Pursuant to 43 CFR 3432.2(c), "the lands applied for shall be added to the existing lease without competitive bidding, but the United States shall receive the fair market value of the lease of the added lands, either by cash payment or adjustment of the royalty applicable to the lands added to the lease by the modification." The BLM will implement this requirement by adding the bonus obligation owed for mining the coal in these two tracts and it will be reported in addition to the royalty. The lessee will pay the fair market value (FMV) bonus payment for the coal resources produced in the Federal coal lease modifications for Federal Coal Leases UTU-014218 designated as Tract 2 and UTU-0126947 designated as Tract 2 on the Federal Coal Lease Form.

The FMV was determined at $0.39 per ton of the actual coal produced. This rate shall be adjusted by the BLM annually (previous 12 months) using the U. S. Bureau of Labor Statistics CPI West Urban Energy Index; or if that index is not available an index that is mutually agreed to by the lessee and the authorized officer will be used.

Payment of the bonus shall be at the specified FMV rate ($0.39 per ton) plus the adjustment times the monthly tonnage mined in each tract. This will be on the schedule required for payment of production royalties to the Office of Natural Resources Revenue (ONRR). The lessee will clearly indicate which portion of the payment is for underground royalty of 8% (or approved reduced royalty rate) and the value for the lease bonus payment ($0.39 plus adjustment). The lessee shall notify the BLM when mining has begun on the tracts and the BLM will calculate the adjustment value of the bonus bid for the next 12 months. Each month as part of the production verification, the lessee shall identify to the BLM the amount of coal mined in these 2 tracts as a separate line item on the submission.

20. In addition, the lessee shall employ measures that will minimize exposure of the general public to air pollutants exhausting from mine portals/adits. Measures may include the use of fencing or other physical barriers, natural barriers, signage, or other measures that preclude public access to the portals/adits. Persons who require legal or practical access to the air vents, such as mine employees or business invitees and guests of the mine, are not considered members of the general public and would continue to have access to these areas.

SPECIAL STIPULATIONS FOR UTU-0126947 MODIFIED COAL LEASE

1. In accordance with Sec. 523(b) of the "Surface Mining Control and Reclamation Act of 1977," surface mining and reclamation operations conducted on this lease are to conform with the requirements of this act and are subject to compliance with Office of Surface Mining regulations, or as applicable the Utah program approved under the cooperative agreement in accordance with sec. 523(c). The United States Government does not warrant that the entire tract will be susceptible to mining.

2. Before undertaking activities that may disturb the surface of previously undisturbed leased lands, the lessee may be required to conduct a cultural resource inventory and a paleontological appraisal of the areas to be disturbed. These studies shall be conducted by qualified professional cultural resource specialists or qualified paleontologists, as appropriate, and a report prepared itemizing the findings. A plan will then be submitted making recommendations for the protection of, or measures to be taken to mitigate impacts for identified cultural or paleontological resources.

If cultural resources or paleontological remains (fossils) of significant scientific interest are discovered during operations under this lease, the lessee prior to disturbance shall, immediately bring them to the attention of the Authorized Officer. Paleontological remains of significant scientific interest do not include leaves, ferns, or dinosaur tracks commonly encountered during underground mining operations.

The cost of conducting the inventory, preparing reports, and carrying out mitigating measures shall be borne by the lessee.

3. If there is reason to believe that Threatened or Endangered (T&E) species of plants or animals, or migratory bird species of high Federal interest occur in the area, the Lessee shall be required to conduct an intensive field inventory of the area to be disturbed and/or impacted. The inventory shall be conducted by a qualified specialist and a report of findings will be prepared. A plan will be prepared making recommendations for the protection of these species or action necessary to mitigate the disturbance.

The cost of conducting the inventory, preparing reports, and carrying out mitigating measures shall be borne by the lessee.

4. Before undertaking activities that may disturb the surface of previously undisturbed leased lands, the lessee may be required to conduct a paleontological appraisal of the areas to be disturbed. The appraisal shall be conducted by a qualified paleontologist and a report prepared itemizing the findings.

A plan will then be submitted making recommendations for the protection of, or measures to be taken to mitigate impacts for identified paleontological resources.

If paleontological remains (fossils) of significant scientific interest are discovered during operations under this lease, the lessee shall immediately bring them to the attention of the authorized officer who shall evaluate, or have evaluated such discoveries and, within 5 working days, shall notify the lessee what action shall be taken with respect to such discoveries. Paleontological remains of significant scientific interest do not include leaves, ferns, or dinosaur tracts commonly encountered during underground mining.

The cost of conducting the inventory, preparing reports, and carrying out necessary protective mitigating measure shall be borne by the lessee. The cost of salvage of paleontological remains (fossils) shall be borne by the United States.

5. The Lessee shall be required to perform a study to secure adequate baseline data to quantify the existing surface resources on and adjacent to the lease area. Existing data may be used if such data are adequate for the intended purposes. The study shall be adequate to locate, quantify, and demonstrate the interrelationship of the geology, topography, surface and ground water hydrology, vegetation and wildlife. Baseline data will be established so that future programs of observation can be incorporated at regular intervals for comparison.

6. Powerlines used in conjunction with the mining of coal from this lease shall be constructed so as to provide adequate protection for raptors and other large birds. When feasible, powerlines will be located at least 100 yards from public roads.

7. The lessee shall provide for the suppression and control of fugitive dust on haul roads and at coal-handling and storage facilities on the lease area. The migration of road surfacing and subsurface materials into streams and water courses shall be prevented.

8. The lessee shall be required to establish a monitoring system to locate, measure, and quantify the progressive and final effects of underground mining activities on the topographic surface, underground and surface hydrology and vegetation. The monitoring system shall utilize techniques which will provide a continuing record of change over time and an analytical method for location and measurement of a number of points over the lease area. The monitoring shall incorporate and be an extension of the baseline data. The monitoring system shall be adequate to locate and quantify, and demonstrate the inter-relationship of the geology, topography, surface hydrology, vegetation and wildlife.

9. Except at locations specifically approved by the Authorized Officer with concurrence of the surface management agency, underground mining operations shall be conducted in such a manner so as to prevent surface subsidence that would: (1) cause the creation of hazardous conditions such as potential escarpment failure and landslides, (2) cause damage to existing surface structures, and (3) damage or alter the flow of perennial streams. The lessee shall provide specific measures for the protection of escarpments and determine corrective measures to assure that hazardous conditions are not created.

10. In order to avoid surface disturbance on steep canyon slopes and to preclude the need for surface access, all surface breakouts for ventilation tunnels shall be constructed from inside the mine, except at specifically approved locations.

11. If removal of timber is required for clearing of construction sites, etc., such timber shall be removed in accordance with the regulation of the surface management agency.

12. Support facilities, structures, equipment, and similar developments will be removed from the lease area within 2 years after the final termination of use of such facilities. This provision shall apply unless the requirement of Section 10 of the lease form is applicable. Disturbed areas and those areas previously occupied by such facilities will be stabilized and rehabilitated, drainages reestablished, and the areas returned to an authorized post mining land use.

13. The Lessee at the conclusion of the mining operation, or at other times as surface disturbance related to mining may occur, will replace all damaged, disturbed, or displaced corner monuments (section corners, quarter corners, etc.) their accessories and appendages (witness trees, bearing trees, etc.), or restore them to their original condition and location, or at other locations that meet the requirements of the rectangular surveying system. This work shall be conducted at the expense of the Lessee, by BLM to the standards and guidelines found in the Manual of Surveying Instructions, U.S. Department of Interior.

14. Notwithstanding the approval of a resource recovery and protection plan by the BLM, lessor reserves the right to seek damages against the operator/lessee in the event (I) the operator/lessee fails to achieve maximum economic recovery [as defined at 43 CFR §3480.0-5(21)] of the recoverable coal reserves or (ii) the operator/lessee is determined to have caused a wasting of recoverable coal reserves. Damages shall be measured on the basis of the royalty that would have been payable on the wasted or un-recovered coal.

The parties recognize that under an approved R2P2, conditions may require a modification by the operator/lessee of that plan. In the event a coal bed or portion thereof is not to be mined or is rendered un-minable by the operation, the operator shall submit appropriate justification to obtain approval by the AO to leave such reserves unmined. Upon approval by the AO, such coal beds or portions thereof shall not be subject to damages as described above. Further, nothing in this section shall prevent the operator/lessee from exercising its right to relinquish all or a portion of the lease as authorized by statute and regulation.

In the event the AO determines that the R2P2 modification will not attain MER resulting from changed conditions, the AO will give proper notice to the operator/lessee as required under applicable regulations. The AO will order a new R2P2 modification if necessary, identifying additional reserves to be mined in order to attain MER. Upon a final administrative or judicial ruling upholding such an ordered modification, any reserves left un-mined (wasted) under that plan will be subject to damages as described in the first paragraph under this section.

Subject to the right to appeal hereinafter set forth, payment of the value of the royalty on such un-mined recoverable coal reserves shall become due and payable upon determination by the AO that the coal reserves have been rendered un-minable or at such time that the lessee has demonstrated an unwillingness to extract the coal.

The BLM may enforce this provision either by issuing a written decision requiring payment of the MMS demand for such royalties, or by issuing a notice of non-compliance. A decision or notice of non-compliance issued by the lessor that payment is due under this stipulation is appealable as allowed by law.

15. The lessee, at his expense, will be responsible to replace any surface water sources identified for protection, that may be lost or adversely affected by mining operations, with water from an alternate source in sufficient quantity and quality to maintain existing riparian habitat, fishery habitat, livestock and wildlife use, or other land uses (authorized by 26 CFR 251).

16. WASTE CERTIFICATION: The lessee shall provide upon abandonment and/or sealing off a mined area and prior to lease termination/relinquishment, certification to the lessor that, based upon a complete search of all the operator's records for the mine and upon their knowledge of past operations, there has been no hazardous substances per (40 CFR 302.4) or used oil as per Utah State Management Rule R-315-15, deposited within the lease, either on the surface or underground, or that all remedial action necessary has been taken to protect human health and the environment with respect to any such substances remaining on the property. The back-up documentation to be provided shall be described by the lessor prior to the first certification and shall include all documentation applicable to the Emergency Planning and Community Right-to-know Act (EPCRA, Public Law 99-499), Title III of the Superfund Amendments and Reauthorization Act of 1986 or equivalent.

17. ABANDONMENT OF EQUIPMENT: The lessee/operator is responsible for compliance with reporting regarding toxic and hazardous material and substances under Federal Law and all associated amendments and regulations for the handling such materials on the land surface and in underground mine workings.

The lessee/operator must remove mine equipment and materials not needed for continued operations, roof support and mine safety from underground workings prior to abandonment of mine sections. Exceptions can be approved by the Authorized Officer (BLM) in consultation with the surface management agency. Creation of a situation that would prevent removal of such material and by retreat or abandonment of mine sections without prior authorization would be considered noncompliance with lease terms and conditions and subject to appropriate penalties under the lease.

18. UNDERGROUND INSPECTION: All safe and accessible areas shall be inspected prior to being sealed. The lessee shall notify the Authorized Officer in writing 30 days prior to the sealing of any areas in the mine and state the reason for closure. Prior to seals being put into place, the lessee shall inspect the area and document any equipment/machinery, hazardous substances, and used oil that is to be left underground.

The purpose of this inspection will be: (1) to provide documentation for compliance with 42 U.S.C. 9620 section 120(h) and State Management Rule R-315-15, and to assure that certification will be meaningful at the time of lease relinquishment, (2) to document the inspection with a mine map showing location of equipment/machinery (model, type of fluid, amount remaining, batteries etc.) that is proposed to be left underground. In addition, these items will be photographed at the lessee's expense and shall be submitted to the Authorized Officer as part of the certification. The abandonment of any equipment/machinery shall be on a case by case basis and shall not be accomplished unless the Authorized Officer has granted a written approval.

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19. FAIR MARKET VALUE BONUS: Pursuant to 43 CFR 3432.2(c), "the lands applied for shall be added to the existing lease without competitive bidding, but the United States shall receive the fair market value of the lease of the added lands, either by cash payment or adjustment of the royalty applicable to the lands added to the lease by the modification." The BLM will implement this requirement by adding the bonus obligation owed for mining the coal in these two tracts and it will be reported in addition to the royalty. The lessee will pay the fair market value (FMV) bonus payment for the coal resources produced in the Federal coal lease modifications for Federal Coal Leases UTU-014218 designated as Tract 2 and UTU-0126947designated as Tract 2 on the Federal Coal Lease Form.

The FMV was determined at $0.39 per ton of the actual coal produced. This rate shall be adjusted by the BLM annually (previous 12 months) using the U. S. Bureau of Labor Statistics CPI West Urban Energy Index; or if that index is not available an index that is mutually agreed to by the lessee and the authorized officer will be used.

Payment of the bonus shall be at the specified FMV rate ($0.39 per ton) plus the adjustment times the monthly tonnage mined in each tract. This will be on the schedule required for payment of production royalties to the Office of Natural Resources Revenue (ONRR). The lessee will clearly indicate which portion of the payment is for underground royalty of 8% (or approved reduced royalty rate) and the value for the lease bonus payment ($0.39 plus adjustment). The lessee shall notify the BLM when mining has begun on the tracts and the BLM will calculate the adjustment value of the bonus bid for the next 12 months. Each month as part of the production verification, the lessee shall identify to the BLM the amount of coal mined in these 2 tracts as a separate line item on the submission.

20. In addition, the lessee shall employ measures that will minimize exposure of the general public to air pollutants exhausting from mine portals/adits. Measures may include the use of fencing or other physical barriers, natural barriers, signage, or other measures that preclude public access to the portals/adits. Persons who require legal or practical access to the air vents, such as mine employees or business invitees and guests of the mine, are not considered members of the general public and would continue to have access to these areas.

APPENDIX C

Description of Connected Actions and Past, Present, and Reasonably Foreseeable Future Actions

DESCRIPTION OF CONNECTED ACTIONS

As defined in the BLM NEPA Handbook (H-1790-1) Section 6.5.2.1 (page numbers 45–48) established by Permanent Instruction Memorandum (PIM 2018-023), connected actions are

> those proposed Federal actions that are "closely related" and "should be discussed" in the same NEPA document (40 CFR 1508.25 (a)(1)). Proposed actions are connected if they automatically trigger other actions that may require an environmental impact statement; cannot or will not proceed unless other actions are taken previously or simultaneously; or if the actions are interdependent parts of a larger action and depend upon the larger action for their justification (40 CFR 1508.25 (a)(1)). Connected actions are limited to Federal actions that are currently proposed (ripe for decision). Actions that are not yet proposed are not connected actions but may need to be analyzed in the cumulative effects analysis if they are reasonably foreseeable.
>
> If the connected action is also a proposed BLM action, we recommend that you include both actions as aspects of a broader "proposal" (40 CFR 1508.23), analyzed in a single NEPA document. You may either construct an integrated purpose and need statement for both your proposed action and the connected action, or you may present separate purpose and need statements for your proposed action and the connected action. Regardless of the structure of the purpose and need statement(s), you must develop alternatives and mitigation measures for both actions (40 CFR 1508.25(b)), and analyze the direct, indirect, and cumulative effects of both actions (40 CFR 1508.25(c)).

None of the past, present, and reasonably foreseeable future coal leasing actions described in Section 3.1.2 are considered connected actions to the Proposed Action analyzed in this EA for reasons described below.

- UEI SITLA coal lease – This action is not a connected action because the SITLA coal leases have already been granted to UEI and the mining of this leased coal does not rely upon leasing or mining of the Lila Canyon Mine.
- Williams Draw LBA – This action is not a connected action because the leasing or mining of the Williams Draw tract is not reliant upon approval of the proposed lease modifications.
- Walker Flat LBA – This action is not a connected action because the operation of the Bronco Mine is not reliant upon the Lila Canyon Mine or the leasing or mining of the Williams Draw tract.

PAST, PRESENT, AND REASONABLY FORESEEABLE FUTURE ACTIONS

Table C-1. Past and Present Actions – Lila Canyon Lease Modifications Resource Analysis Areas

Action	Location	Specific	Past, Present	Measure	Resource considered
Coal mining					
	Emery County	UEI - Lila Canyon Mine	Past, present	2019 production 3,664,000 tons	Energy production
		Canyon Fuel/Wolverine - Skyline #3 Mine	Past, present	2019 production 3,896,000 tons	Energy production
		Bronco - Emery Mine	Past, present	2019 production 694,000 tons	Energy production
		Castle Valley/Rhino Resources – Castle Valley #1 Mine	Past	(inactive since 2004)	N/A
		Castle Valley/Rhino Resources – Castle Valley #3 Mine	Past, present	2019 production 562,000 short tons	Energy production
		Castle Valley/Rhino Resources – Castle Valley #4 Mine	Past, present	2019 production 488,000 short tons	Energy production
		East Mountain Energy -Deer Creek Mine	Past	(inactive since 2016)	N/A
		Genwal/UEI - Crandall Canyon Mine	Past	(inactive since 2008)	N/A
		Genwal/UEI - South Crandall Canyon	Past	(inactive since 2007)	N/A
	Carbon County	UEI – Aberdeen Mine	Past	(inactive since 2009)	N/A
		UEI – Pinnacle Mine	Past	(inactive since 2007)	N/A
		Canyon Fuel/Wolverine - Dugout Canyon Mine	Past, present	2019 production 430,000 short tons	Energy production
		Hidden Splendor – Horizon Mine	Past	(inactive since 2013)	N/A
		Lodestar – Whisky Creek #1	Past	(inactive since 2004)	N/A
		West Ridge/UEI/ Murray – West Ridge Mine	Past	(inactive since 2016)	N/A
	Utah	Statewide	Past, present	2019 production 7,966,094 tons	
	New Mexico	Statewide	Past, present	2019 production 167,802,210 tons	
	Colorado	Statewide	Past, present	2019 production 6,992,221 tons	
	Wyoming	Statewide	Past, present	2019 production 48,404,660 tons	

Action	Location	Specific	Past, Present	Measure	Resource considered
Mineral mining					
	Emery County	Clay, humic shale, gypsum, U308&V205, boulders, riprap, gold, septarians, sandstone, flagstone, bentonite/zeolite	Past, present	Total 21 active mines; four are large mining operations, 17 are small mining operations or lode claims. The nearest active mine is approximately 19 miles northwest of Lila Canyon Mine.	Minerals
	Carbon County	Sandstone	Past, present	Total 1 active mine	Minerals
Oil and gas production					
	Emery and Carbon Counties	Oil Natural gas	Past, present	See EA Table 3-20	
	Utah	Oil and natural gas statewide	Past, present	13,835 producing wells in 2019; 38.4 MMT annual CO_2e	GHG, climate change
Other					
	Emery and Carbon Counties	Coal-fired power plants	Past, present	Emissions contribute to affected environment conditions. No new coal-fired generators have been built in Utah since 1993 (EIA 2020).	Affected environment; air quality; GHG, climate change; indirect effects of combustion

Table C-2. Reasonably Foreseeable Future Actions in the Lila Canyon Lease Modifications Resource Analysis Areas

Action	Location	Specific	RFFA	Measure	Resource considered
Coal mining					
	Emery County	UEI Williams Draw LBA	RFFA	Approximately 32 million tons recoverable coal; permitted maximum production 4.5 million TPY	Air quality Socioeconomics Water resources
		SITLA coal lease	RFFA	Approximately 4–5 million tons recoverable coal	Air quality Socioeconomics Water resources
		Walker Flat LBA	RFFA	Approximately 8.2 million tons recoverable coal as stated in the application	Socioeconomics
		Canyon Fuel/Wolverine Little Eccles LBA	RFFA	(approx. 80 km away from Lila Canyon Mine)	None (located outside resource analysis areas)
Mineral mining					
	Emery County	Chalk Hills Expansion	RFFA	Active mining disturbance ≤ 10 acres at any given time over nearly 40 years; DOGM permit required prior to mining in expansion area	Air quality Socioeconomics

Action	Location	Specific	RFFA	Measure	Resource considered
Oil and gas leasing/production					
	Carbon and Emery Counties	Quarterly oil and gas lease sales	RFFA once APD process is completed	Production, once operating	Socioeconomics
		IACX Woodside Dome 1 APD	RFFA once APD process is completed	Production, once operating	Air quality Socioeconomics
		Twin Bridges Bowknot Helium	RFFA once APD process is completed	Production, once operating	Socioeconomics
	Carbon County	EnerVest Peters Point APDs	RFFA once APD process is completed	Production, once operating	Socioeconomics (outside 50 km for air quality analysis)
Transportation					
7-County Coalition	Carbon County	Uinta Basin Railway	RFFA		None (located outside all resource analysis areas)
Other					
	Emery County	E Carbon junction fiber	RFFA	Temporary disturbance, socioeconomic effect	Air quality Socioeconomics

APPENDIX D

Excerpts from 2020 BLM GHG and Climate Change Report

3.0 Emissions Calculations

This document contains several emissions estimates for the three primary GHGs of concern (CO_2, CH_4, N_2O) at various scopes (direct and indirect) and scales (state and cumulative). The estimates provide a baseline to contrast federal emissions with those of the broader economy (national and global) and illustrate the degree to which federal mineral development contributes to projected energy use and climate change.

For the purposes of this report, the BLM is estimating both direct and indirect GHG emissions from federal fossil fuel production and consumption. The term *direct* is used here to describe development- and production-related emissions (i.e., upstream) that could be considered the most applicable or attributable to the purview of the BLM's authority for onshore federal mineral estate management. Direct emissions could result from broad resource use activities such as lease exploration, access roads, well pad or coal mine development, well drilling and completions, recurring maintenance and production equipment operations, and site reclamation. The term *indirect* is used here to describe emission elements that are outside of the BLM's oversight authority, such as midstream infrastructure development and maintenance, transportation and distribution, processing and refining, and the ultimate end use (including combustion) of any federal minerals produced. The sum of direct and indirect GHG emissions account for each stage of federal mineral production and use, which is also known as a life-cycle assessment (LCA).

To estimate emissions the BLM is using production data and statistics from the Energy Information Administration (EIA) and the Office of Natural Resources Revenue (ONRR), both of which provide production accounting services for domestic fossil fuel minerals. The production values used in this report are the extracted or gross withdrawn volumes, as reported on a calendar year basis. All end-use emissions are being estimated using EPA emissions factors from Appendix Tables C-1 and C-2 of 40 CFR Part 98, Subpart C, as shown in Table 2 below.

Table 2 - Downstream Combustion Emissions Factors

Fuel Stock	CO_2	CH_4	N_2O	CO_2e [2]	% CO_2	% CH_4	% N_2O
Crude Oil (kg/gallon) [1]	10.29	4.1E-04	8E-05	10.33	99.62	0.14	0.23
Natural Gas (kg/scf) [1]	0.05444	1.03E-06	1E-07	0.05451	99.88	0.07	0.06
Bituminous Coal (kg/ton) [1]	2,325.47	0.274	0.04	2,347.23	99.07	0.42	0.51

[1] Equivalent EFs: EPA GHG Emissions Factors.
[2] CO2e values calculated from AR5 GWPs (100-year w/climate feedbacks).

The reported production data serves as the primary input for the delineation of direct and indirect emission estimates by applying published LCA data, other studies and statistics, and assumptions for each fossil fuel type as follows:

Coal

Virtually all of the coal produced in the U.S. is classified as either thermal (steam coal) or metallurgical (met or coking coal). Steam coal has a variety of energy-related uses in several sectors of the economy, including as a primary fuel for baseload electrical generating plants. Met coal is used (indirectly, as coke) as a fuel and reactant in steel production blast furnaces.

Regardless of classification, the BLM is unaware of any non-combustion base uses for coal stocks beyond trivial scales and is thus assuming 100% combustion of all coal production.

To estimate the LCA emissions associated with federal coal production in the U.S., this report is relying on data obtained from a recent BLM-sponsored study that examined coal mine emissions in four western states that represent a majority of the federal coal estate. The study examined various production metrics of operational mines (underground and surface) in each state to evaluate the GHG emissions profiles for extraction, processing, venting, transport, and end-use (combustion). An analysis of the study data suggests that the cradle-to-gate emissions from mining activities (direct emissions) and coal transport are approximately 3.072% of the relative combustion emissions (carbon dioxide equivalent [CO_2e] basis) as a function of production. The results of the BLM study are consistent with other external data sources researched[3] in preparation for this report, and as such the data is deemed reasonable for estimation purposes.

Natural Gas

Natural gas stocks are used as an energy source (via combustion) in virtually every sector of the economy. The industrial sector also uses natural gas as a raw material to produce chemicals, fertilizer, and hydrogen. However, most of the processes that support the chemical transformation of CH_4 (natural gas) into these products generate a stoichiometric amount of CO_2 emissions relative to the mass of the feedstocks used in the process. And so for the purposes of this report, the BLM is assuming that any products made from natural gas feedstocks would release GHGs equivalent to a combustion rate.

To account for the LCA emissions associated with natural gas production, the BLM is relying on data published by the Department of Energy's National Energy Technology Laboratory (DOE-NETL) in a report titled *Life Cycle Analysis of Natural Gas Extraction and Power Generation*[4]. The NETL report provides a detailed examination of the natural gas supply chain in the U.S. broken down by basin and resource type. The calculations in this report are based on the national averages published in the NETL report, as these values provide a reasonable estimation of emissions based on the fractions of production the representative federal basins contribute to total U.S. production (see Exhibits 2-2, 2-3, and 6-6). The report concludes that the average life-cycle GHG emissions from the U.S. natural gas supply chain are 19.9 grams (g) of CO_2e per megajoule (MJ) of delivered (i.e., combusted) natural gas. The CO_2e factors in the NETL report are based on 100-year AR5 estimates with climate feedbacks. The report also concludes that total CH_4 emissions throughout the supply chain are approximately 1.24% of the production volume (see Exhibit 6-2). The loss of gas throughout the supply chain represents a reduction of the available gas that could be combusted by the same fraction, and so for accounting purposes the BLM is assuming a combustion rate of 98.76% of all production volumes. The national average CH_4 emissions from the supply chain are estimated to account for approximately 11.15% of the total LCA CO_2e contribution. In terms of emissions speciation, CH_4 alone accounts for 7.848 g CO_2e/MJ (0.218 g CH_4/MJ) of the total supply chain CO_2e factor. The BLM is assuming that 100% of the production, gathering, and boosting emissions from the supply chain processes are a part of the direct emissions scope from federal production. The direct emissions of CO_2 and CH_4 from the federal production supply chain are estimated to be 6.052 g/MJ and 0.131 g/MJ, respectively.

Exhibit 2-2. Basins that Account for Majority of U.S. Natural Gas Production

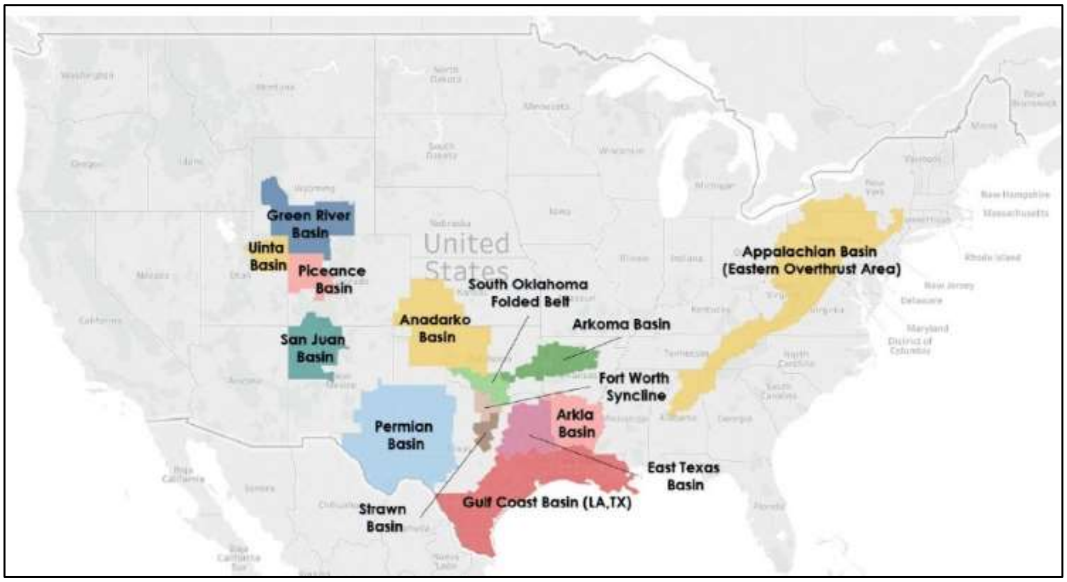


Exhibit 2-3. Natural Gas Production Shares by Well Type and Geography

Geography	Well Type						
	Conventional	Shale	Tight	CBM	Offshore	Associated	Total
Onshore Production							
Anadarko	2.2%	2.6%	1.7%				6.5%
Appalachian		29.0%					29.0%
Arkla	0.4%	4.2%	1.4%				6.0%
Arkoma	0.3%	0.9%					1.2%
East Texas	1.6%	1.3%	1.3%				4.2%
Fort Worth Syncline		1.8%	0.0%				1.8%
Green River	1.6%		3.9%				5.5%
Gulf Coast	0.8%	6.6%	1.3%				8.7%
Permian	2.3%	5.3%					7.6%
Piceance			0.3%				0.3%
San Juan	1.4%			1.9%			3.3%
South Oklahoma		1.0%					1.0%
Strawn		3.2%					3.2%
Uinta	0.5%		0.8%				1.3%
*Subtotal: Onshore**	*11.0%*	*56.0%*	*10.6%*	*1.9%*			*79.6%*
Offshore Production							
Offshore Gulf of					4.2%		4.2%
Offshore Alaska					0.1%		0.1%
Subtotal: Offshore					*4.3%*		*4.3%*
Associated Gas							
United States						16.1%	16.1%
Total							
*Total**	*11.0%*	*56.0%*	*10.6%*	*1.9%*	*4.3%*	*16.1%*	*100%*

Exhibit 6-6. Life Cycle GHG Emissions for Natural Gas Scenarios (100-year CO_2e)

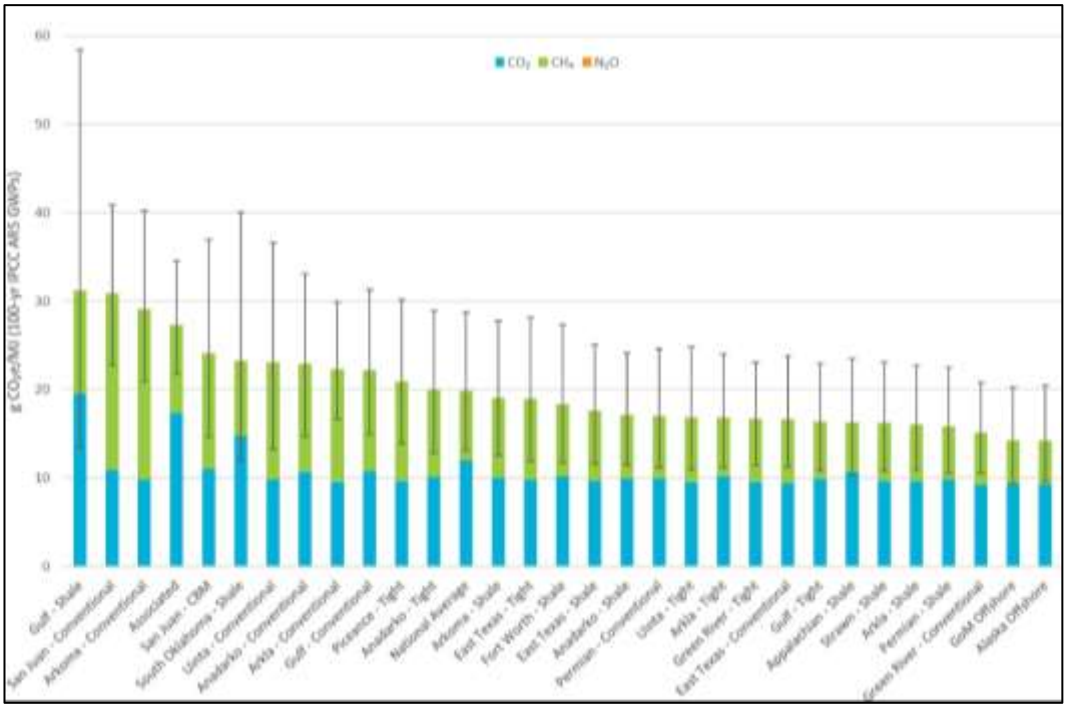


Exhibit 6-1. Life-Cycle GHG Emissions for the U. S. Natural Gas Supply Chain

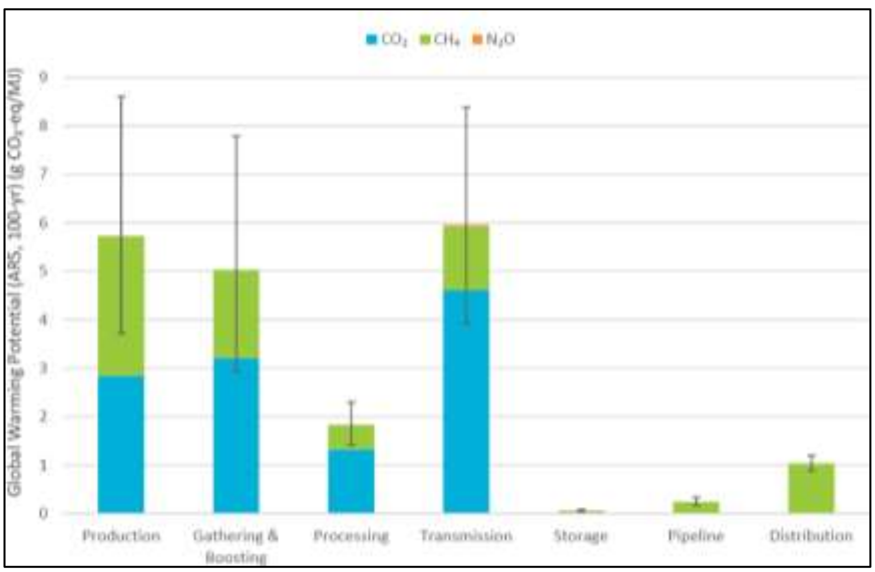


Exhibit 6-2. Life-Cycle CH_4 Emissions for the U.S. Natural Gas Supply Chain

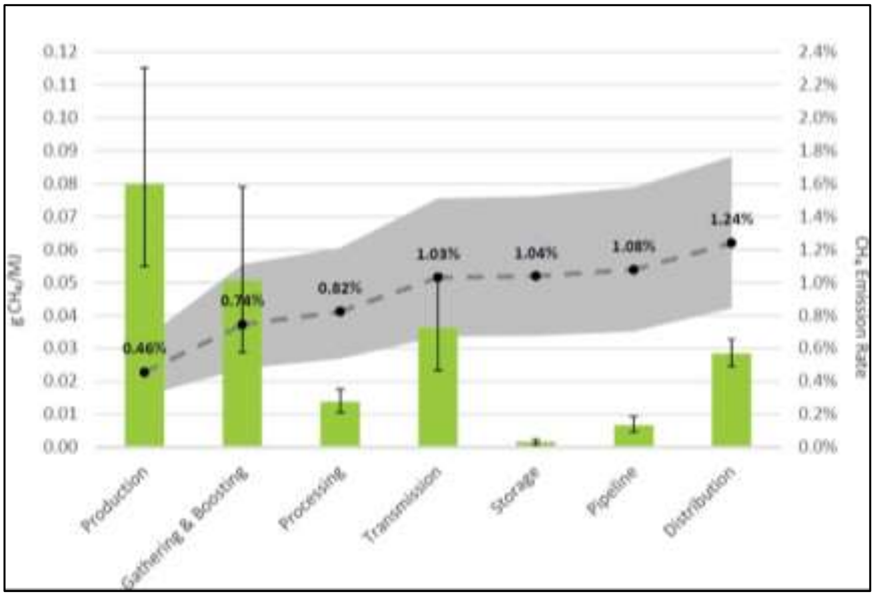


Figure 1 - NETL Natural Gas LCA Data

Petroleum

EIA data show that approximately 95% of oil stocks in the U.S. are transformed into fuels, while the remainder is refined to produce a range of petrochemical products such as plastics and other consumables. The refining process requires additional feedstocks to be blended with the crude oil in order to make the chemistry work, meet regulatory requirements, or yield the desired product profiles. Because of the additives and the fact that most of the products refineries produce are less dense than the crude oil stock, the output volume is greater than that of the initial crude stocks by approximately 5%. This gain, formally known in the industry as process gain, means that the percentage of crude oil stocks used to produce combustible products is essentially equivalent to the original produced crude oil volumes, and so for the purposes of this report, the BLM is assuming a 100% combustion rate for crude oil production.

To account for the methods and infrastructure used to produce and market crude oil products, this report relies on published data produced in part by the DOE-NETL, which updates its 2005 well-to-wheels (WTW) life-cycle GHG analysis of petroleum-based fuels consumed in the U.S.[5]The update focuses on three primary products derived from crude oil—gasoline, diesel, and jet fuel—which, according to the EIA, account for approximately 83% of the potential crude oil stock uses in the U.S. To estimate crude oil life-cycle emissions from the reported production volumes, the BLM is calculating a weighted average of NETL's updated modeled LCA emission factors as derived from the EIA product percentages. Table 4 shows the LCA emissions factors and the derived weighted fraction factors applied in this report. The LCA combustion data is shown and used to calculate the relative percentages the other life-cycle process emissions represent relative to combustion.

Table 4 - Petroleum Life-Cycle CO2e Emissions[1]

Data / Product	Gasoline	Jet Fuels		Diesel	Sums / Weighted Fractions	Scope
EIA Product Fractions[2]	0.49	0.09		0.25	0.83	NA
NETL Production	13	13		13	13	Direct
NETL Refining	10.7	2.3		6.8	8.61	Indirect
NETL Transport	1.7	1.6		1.6	1.66	Indirect
NETL Combustion	72.7	73.7		72.7	72.8	Indirect
NETL Total LCA	98.1	90.7		94.1	96.1	NA

[1] NETL LCA emissions units are g CO_2 e/MJ combusted
[2] 2019 U.S. refiner & blender net production fractions

The direct emissions of CH_4 from the petroleum life-cycle systems are assumed to be equivalent to the estimates used for the natural gas systems on a per unit of energy produced basis. This assumption is based in part on the fact that oil wells often produce associated gas along with the liquid hydrocarbons. While the associated gas itself is accounted for in the overall natural gas production data, there are known emissions points within the liquids process streams that could leak CH_4 dissolved in crude oil, such as tanks, pneumatic devices, components, pipelines, etc. Given the inherent variability in the equipment configurations, age, and regulatory requirements applicable to the liquids infrastructure in the U.S., the equivalence assumption, while likely conservative, is reasonable for the purpose of estimating emissions in this report. Further, there was virtually no data that the BLM could find to estimate CH_4 emissions from just the liquids alone (i.e., without the gas context). The assumption is only valid for the direct emissions portion of the life-cycle due to the different processes used to manage a liquid versus a gas in the indirect portions of the process streams. To calculate the energy equivalence of the reported production, the BLM is using published energy data from the above-referenced Part 98 tables for oil (1 barrel of crude oil = 5,796,000 Btu) and gas (1 cubic foot of natural gas = 1,026 Btu).

The LCA data presented in this report is meant to broaden the analysis of the potential direct emissions that could result from the BLM's federal mineral management mission. It is important for readers to understand that the impacts analysis presented in this report is almost entirely based on the end-use (i.e., combustion) emissions, which fully account for all of the fossil fuels available to the economy for primary energy purposes. It would be inappropriate to add the LCA emissions from direct or indirect processes that rely on fossil fuels to the end-use estimates, as this would result in double counting and would bias the impacts assessment. The only exception to this rule is for the accounting of system losses of CH_4 from the oil and gas supply chain and coal mine CH_4, as these gases are never combusted. The loss estimates of CH_4 from processes related to the direct emissions scope are designated as LCA CH_4 in the tables below.

The LCA CH_4 emissions are transformed by the applicable GWP and then added back in to the combustion-related totals to present the total CO_2e estimates used to make projections and impacts assessments discussed later in the report.

Note: Production data from the above-referenced sources is subject to periodic revisions. Necessary corrections required for static data elements in this report will be made during subsequent year updates.

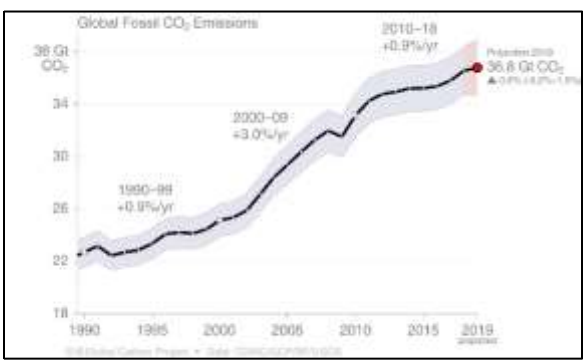
4.0 GHG Emissions Trends

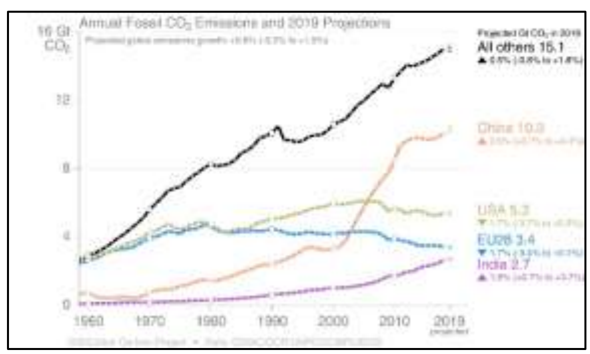
Despite global awareness and acknowledgment of the climate change issue, 2019 saw a continuation of record-setting emission rates around the world. Modernization, population growth, and standard of living advances have all contributed to increased energy demand that, combined with land use changes on 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 36.8 Gt in 2019. This value is equivalent to 10.04 petagrams of carbon (PgC) and most closely tracks the RCP4.5 Fossil Fuel scenario relative to the 2020 emissions year. In the atmosphere, 10.04 PgC is approximately 4.71 ppmv of CO_2, but because of the Carbon cycle, not all of the CO_2 emissions will remain the atmosphere.

The largest single emitter in 2019 was China (28%) followed by the U.S. (14.4%). While China reached a new high for its annual rate, the U.S. remained below the high emissions mark set in 2007 and has been trending somewhat flat for the last decade. The U.S. is by far one of the largest single emitters on a per capita basis, although this trend has been mostly declining over the past two decades. Globally, the use of all fossil fuels continues to increase, where each fuel (and cement production), save for coal, hit new peak emissions levels based on the most recent data available.

The large increases in global coal emissions can mostly be attributed to China, while in the U.S., emissions from this fuel continue to decline at a rapid rate due in part to the competitiveness of natural gas and renewable sources of energy. In the U.S., only natural gas emissions reached a new high mark in 2019. Oil remained below its historical high, but the trend has been increasing year after year for the past 5+ years.

In terms of sector use, heat and electricity accounts for almost half of global fossil fuel GHGs, led by coal fuels. Coal accounts for 73% of heat and electricity emissions and approximately 50% of all industrial emissions. Oil is the dominant fuel of choice in the transportation sector and accounted for close to 97% of the associated emissions. Natural gas is used broadly across all sectors of the global economy and has increasing use rates in each category analyzed.





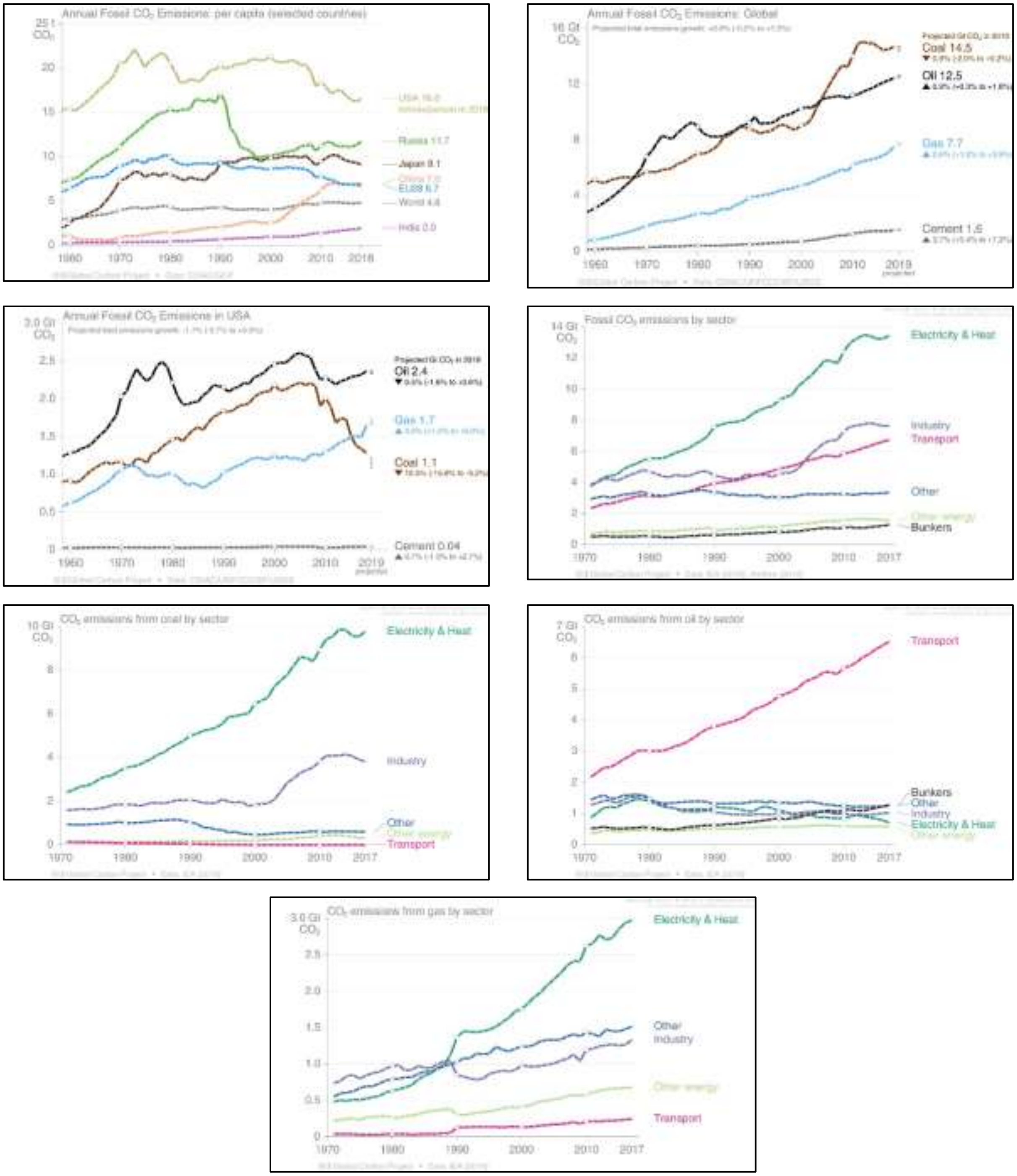


Figure 2 - Global Fossil Fuel Energy Emissions

Domestic Energy and Emissions

According to the latest EPA Greenhouse Gas Inventory Report, in 2018 the U.S. emitted a total of approximately 6,676.65 million metric tons (MMT) of GHGs on a CO_2e basis. CO_2 alone accounted for 81.3% (5,424.88 MMT) of the total emissions, of which energy-related sources emitted 5,249.29 MMT

(96.7%). $CH_4$and NO_2 were the next two largest components of the U.S. emissions spectrum at 9.5% (634.46 MMT) and 6.5% (434.53 MMT), respectively. Energy-related sources accounted for 253.91 MMT (39.1%) and 44.01 MMT (9.9%) of all CH_4 and N_2O emissions on a CO_2e basis, respectively. Together, emissions of all three gases from the energy sector represent approximately 83.1% of all GHGs emitted in the U.S. More sector-specific emissions data can be found on the EPA's Greenhouse Gas Inventory Data Explorer.

On a cumulative basis, the EPA data show that since 1990 the U.S. has emitted approximately 202,283 MMT of CO_2e, at an annual average rate of 7,152.96 MMT. The most recent year emissions data is less than the annual average but remains relatively little unchanged over the last 30 years. However, as stated above, the per capita emissions rate changes show that the U.S. has very much decreased its overall energy use intensity over the past 20 years. According EIA, the annual energy consumption in the U.S. for 1990 was 84.41 quads (quadrillion British thermal units), while in 2019 it was 100.2 quads, which represents an overall increase in energy demand of approximately 15%. The relative energy mix over this same period of time shows a decline in coal of -7.86 quads, while consumption in every other energy category increased (gas +12.5 quads, oil +3.22 quads, nuclear +2.36 quads, renewables +5.42 quads). Although a single snapshot year comparison does not provide the full narrative for the economic dynamics that occurred to result in the fuel use changes over the cumulative period, the data does help to provide a sense of why the U.S. emissions remain relatively flat as tracked. It is clear from the data that increases in energy use efficiency, fuel substitutions, and renewable energy resource development have all combined to offset emissions from the net energy demand increases that have occurred over the same time frame. In terms of energy supply (see Figure 3), the 2019 production data show natural gas provides almost as much energy as petroleum and coal combined. The data also show that on a per unit of energy basis, natural gas is the least-climate-polluting fossil fuel (60.75 MMT/quad) compared to coal (95.89 MMT/quad) and petroleum (83.14 MMT/quad).

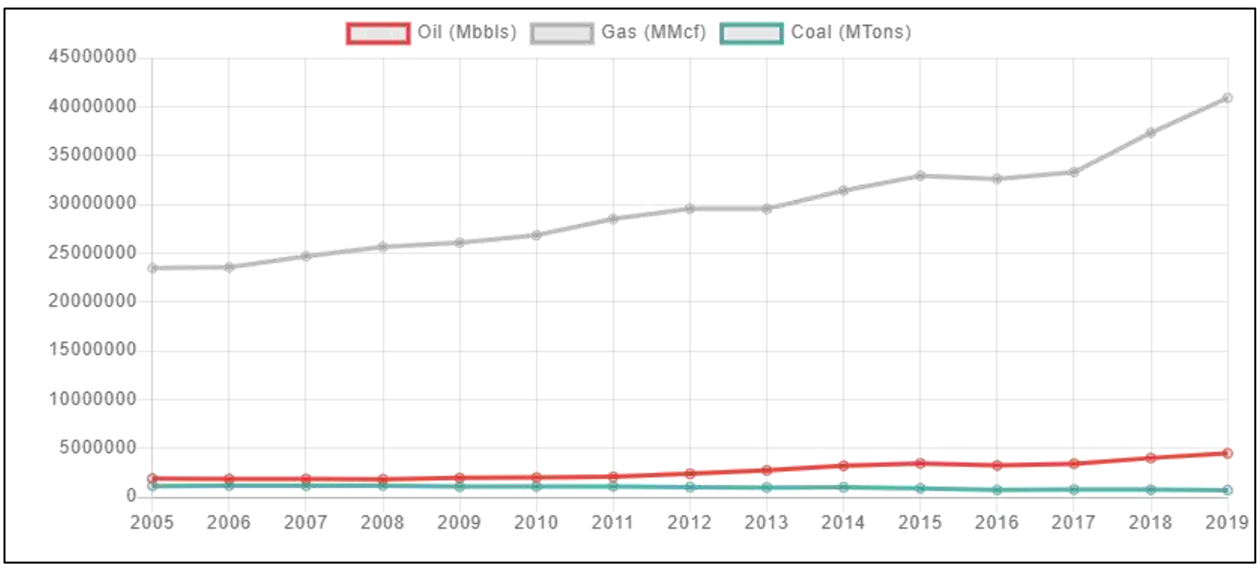
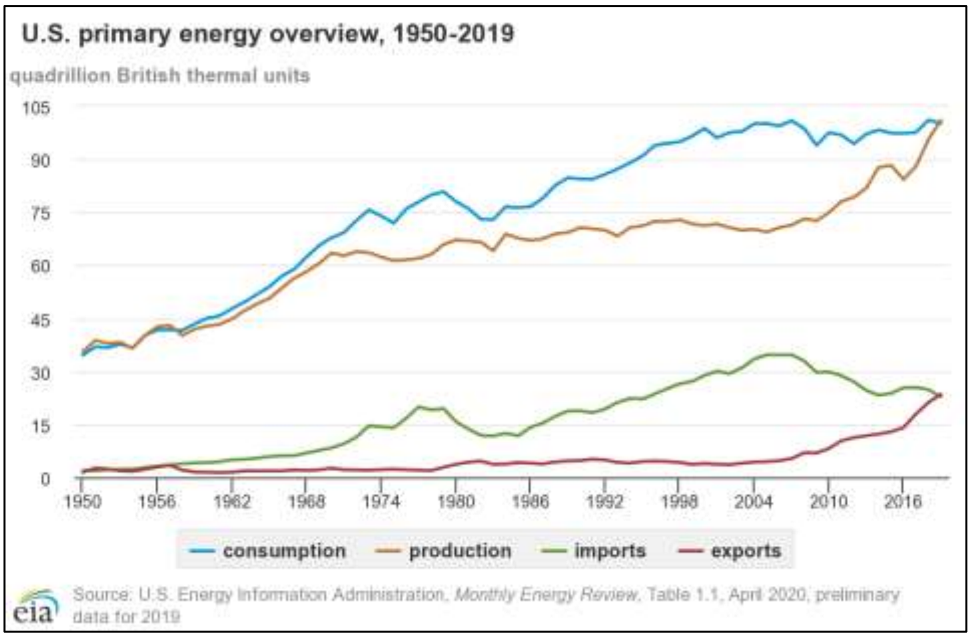
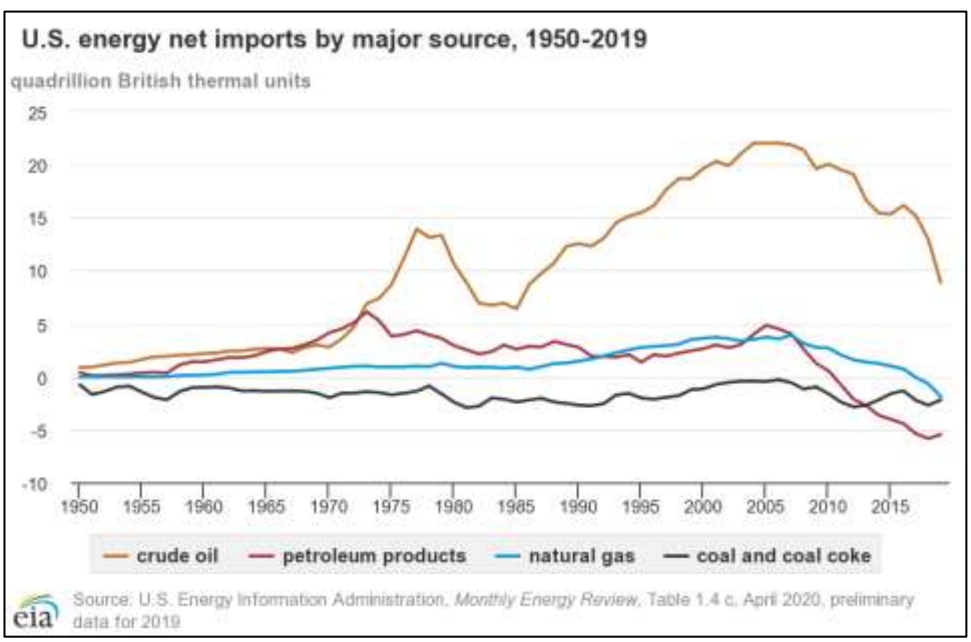
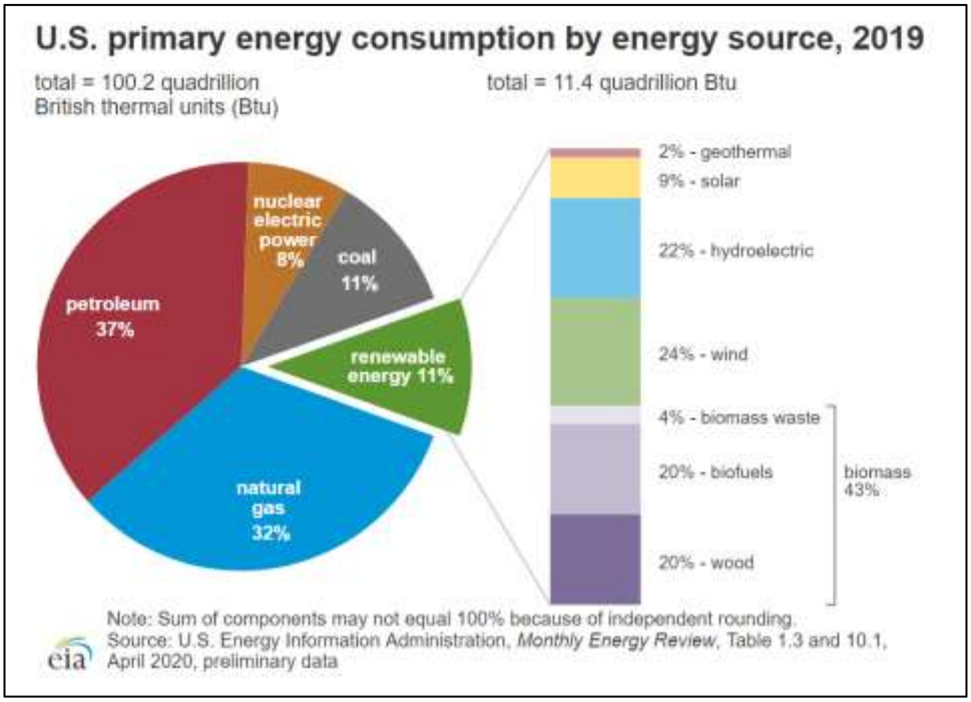


Figure 3 - Domestic Energy Statistics (undefined)

The latest EIA data also show that in 2019 the U.S. became a net energy exporter for the first time in almost 70 years. Crude oil remains the only source of fossil fuel energy that is imported, and these volumes have been mostly declining since 2005. The three major fossil fuels—petroleum (37%), natural gas (32%), and coal (11%)—combined accounted for about 80% of domestic consumption while renewable energy sources (12%) and nuclear electric power (8%) provide the remainder. The year 2019 also marks the first time that consumption of renewable sources of energy surpassed coal in the marketplace. The electrical grid (including energy losses) is in a virtual tie with the transportation sector as the largest source of energy consumption in the U.S., followed by industrial, residential, and commercial uses.







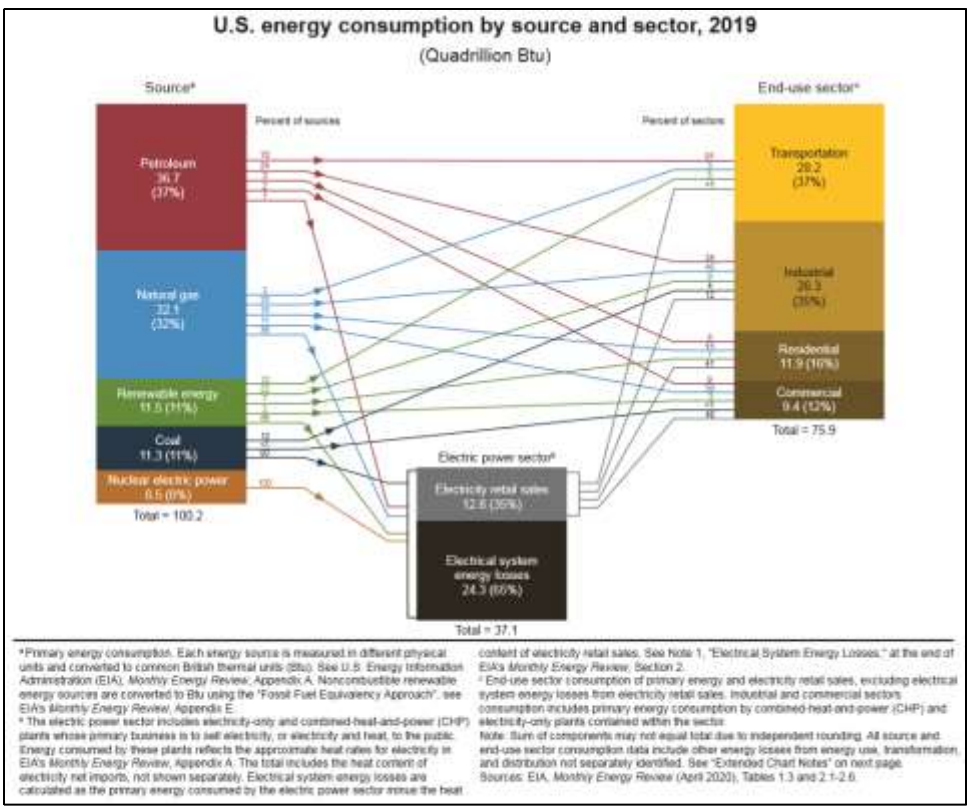


Figure 4 - Domestic Energy Consumption, Net Imports, and End Use

Domestic energy supplies of fossil fuel minerals can generally be classified as either federal or non-federal, where non-federal signifies state, local, private, 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 help meet the demand for energy domestically and abroad. The data tables below show production and emissions data for each mineral type by region. All regions other than U.S. Total represent federal minerals only. The Onshore designation is used to account for all other onshore federal minerals produced in states not explicitly represented by the regions listed in the tables. The % Total and % Federal columns in the production tables are based on the averages of the full 5 years of data presented.

Table 5 - Coal Production Trends (tons) [1]

Region	2015	2016	2017	2018	2019	% Total	% Federal
U.S. Total	896940563	728364498	774609357	756167095	706309263	100%	NA
CO	17124505	10614645	10392779	10620675	10336903	1.53%	3.7%
MT	19063920	13884403	18023605	17626988	15631137	2.18%	5.28%
NM	7657220	4914843	5956595	1754306	3775959	0.62%	1.51%
ND	5261915	4738941	4348995	3849247	4039635	0.58%	1.39%
UT	11364222	12252873	12933852	11051690	12791486	1.56%	3.78%
WY	314632155	244846641	273653181	265503330	244041373	34.76%	84.14%
Onshore	636458	692831	764815	516732	543138	0.08%	0.2%

[1] Federal coal accounts for 41.3% of all U.S. production on a 5-year annual average basis.

Table 6 - Natural Gas Production Trends (Mcf) [1]

Region	2015	2016	2017	2018	2019	% Total	% Federal
U.S. Total	32914647000	32591578000	33292113000	37325539000	40892458000	100%	NA
AK	16642097	14663058	16039628	15315663	18449816	0.05%	0.36%
CA	13291040	12611640	11839226	11918118	6004674	0.03%	0.25%
CO	664983322	626680566	644465321	637440829	664233004	1.83%	14.44%
MT	14119762	12607237	12287580	11627948	10951038	0.03%	0.27%
NM	800540964	786765900	799943219	920956001	1046481774	2.46%	19.42%
ND	41974682	47169787	60564817	73674266	88968419	0.18%	1.39%
UT	264663369	227501512	190401286	164202446	148254680	0.56%	4.44%
WY	1537216372	1438798196	1402608212	1402654935	1255059059	3.97%	31.38%
Onshore[2]	107790704	96272937	96818377	90803086	98688229	0.28%	2.19%
Offshore	1354149051	1256774957	1111100538	1020510066	1058788351	3.28%	25.87%

[1] Federal gas accounts for 12.7% of all U.S. production (including offshore) on a 5-year annual average basis.
[2] Onshore alone accounts for 9.4% of all U.S. gas production on a 5-year annual average basis.

Table 7 - Crude Oil Production Trends (bbl) [1]

Region	2015	2016	2017	2018	2019	% Total	% Federal
U.S. Total	3447970000	3239657000	3420545000	4001892000	4470528000	100%	NA
AK	958054	805788	993799	1033904	1280423	0.03%	0.12%
CA	13421932	11013188	9795602	9504080	9292324	0.29%	1.26%
CO	5028374	4362350	5194434	6822327	6992221	0.15%	0.68%
MT	3294381	3028077	2859730	3368258	3180317	0.08%	0.37%
NM	79464456	76824847	89069273	129250843	167802210	2.92%	12.9%
ND	26666226	25855361	31143984	38720115	44509644	0.9%	3.97%
UT	11463564	9337508	9160104	8155747	7966094	0.25%	1.1%
WY	44402275	37716663	39030469	43960807	48404660	1.15%	5.08%
Onshore[2]	2782516	2690002	2462480	2207843	2331383	0.07%	0.3%
Offshore	565024682	592505843	619871829	647366375	695553235	16.79%	74.22%

[1] Federal petroleum accounts for 22.6% of all U.S. production on a 5-year annual average basis.
[2] Onshore alone accounts for 5.8% of all U.S. petroleum production on a 5-year annual average basis.

Report year (2019) emissions for the production data disclosed above are shown in Table 8. The table shows indirect combustion (Comb) emissions of CO_2 and CO_2e, direct emissions of CH_4 (LCA CH_4), direct LCA emissions from extraction (Extract), indirect LCA emissions from transportation and distribution (Trans), and indirect LCA emissions from processing, refinement, and transformation (Process). The Total CO_2e column is the sum of the combustion CO_2e and LCA CH_4 (as CO_2e) columns and is the metric used for impacts assessments later in the report.

Table 8 - Report Year Emissions (MMT) [2]

Region	Comb CO_2	Comb CO_2e[1]	LCA CH_4	Extract CO_2e	Trans CO_2e	Process CO_2e	Total CO_2e
U.S. Total	5772.48	5826.5	16.4415	1060.19	315.72	370.42	6418.4
AK	1.55	1.57	0.0036	0.32	0.13	0.13	1.69
CA	4.34	4.36	0.0083	0.79	0.13	0.5	4.66
CO	63.22	63.5	0.112	11.75	4.47	2.65	67.54
MT	38.32	38.67	0.0225	5.63	0.29	0.2	39.48
NM	138.25	138.7	0.2872	26.47	8.44	12.22	149.04
ND	33.46	33.64	0.0531	5.85	1.06	2.59	35.55
UT	41.26	41.56	0.0425	6.65	1.18	0.92	43.09
WY	656.74	662.23	0.5043	100.33	11.42	6.81	680.39[3]
Onshore	7.64	7.66	0.0165	1.51	0.66	0.46	8.25
Offshore	358.14	359.48	0.7073	66.23	13.7	39.34	384.94

[1] Comb CO_2e includes combustion related emissions of CH_4 and N_2O as CO_2e using AR5 GWPs values w/CF.
[2] Federal emissions are approximately 22% of the U.S. Total shown (16% for Onshore only).
[3] WY alone accounts for nearly half of all federal emissions, which is largely driven by coal (86%).

Table 9 - Mineral Summary Report Year Emissions (MMT) [2]

Region	Comb CO_2	Comb CO_2e[1]	LCA CH_4	Extract CO_2e	Trans CO_2e	Process CO_2e	Total CO_2e
Fed. Total Coal	5772.48	5826.5	16.4415	1060.19	315.72	370.42	6418.4
Fed. Total Gas	1.55	1.57	0.0036	0.32	0.13	0.13	1.69
Fed. Total Oil	4.34	4.36	0.0083	0.79	0.13	0.5	4.66

1 Comb CO_2e includes combustion related emissions of CH_4 and N_2O as CO_2e using AR5 GWPs values w/CF.
2 All emissions in table 9 are onshore federal.

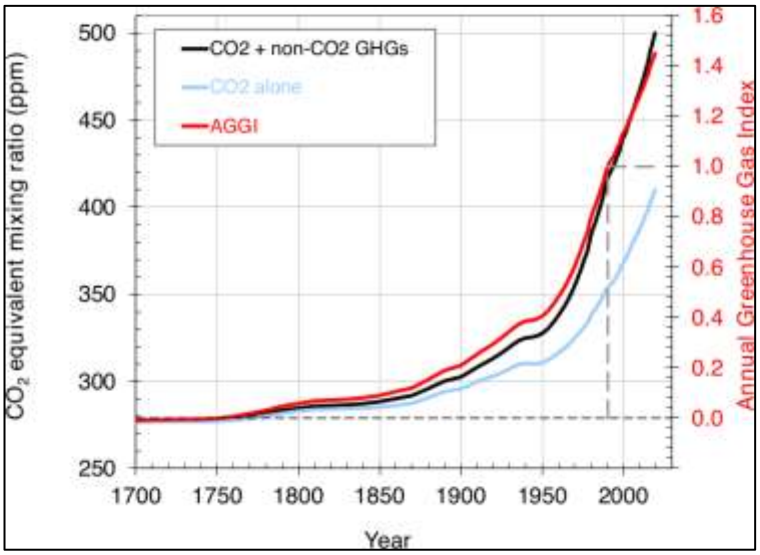


Figure 6 - Climate Feedbacks and AGGI

7.0 Projected Emissions

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

- ***RCP2.6*** *- Very low emissions levels leading to peak in radiative forcing at 3.1 W/m2 by mid-century, returning to 2.6 W/m2 by 2100, where GHG emissions (and indirect* 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 that more carbon is removed from the atmosphere than is emitted. The curve suggests that emissions from fossil fuels and other sources would decline by approximately 3.5% per year until 2040 and then continue at a pace of approximately 10% per year until the emissions become negative between 2070 and 2080. The cumulative emissions of this pathway are approximately 1,715.7 $GtCO_2e$ (2018–2100). CO_2 alone represents 54.2% of the total contributing emissions, and 81.5% of the total CO_2 emissions are attributable to fossil fuel use.

- ***RCP4.5*** *- Stabilization scenario where total radiative forcing is stabilized at 4.5 W/m2 before 2100 by employment of a range of technologies and strategies for reducing GHG 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% of the total contributing emissions, and 98.2% of the total* CO_2 *emissions are attributable to fossil fuel use.*
- ***RCP6.0*** *- Stabilization without overshoot pathway with radiative forcing of 6 W/m2 after 2100 by employment of a range of technologies and strategies for reducing GHG emissions. Emissions of both* CH_4 *and* N_2O *are more or less stable throughout the century and do not contribute significantly to additional radiative forcing, while emissions of* CO_2 *grow steadily until 2080 before declining. The cumulative emissions of this pathway are approximately 5,380.2* $GtCO_2e$ *(2018–2100).* CO_2 *alone represents 74.3% of the total contributing emissions, and 101.1% of the total* CO_2 *emissions are attributable to fossil fuel use. Please note that the land-use change (LUC)* CO_2 *emissions in this scenario are negative at about the mid-century mark, which produces data showing fossil fuel emissions that are greater than the total emissions (which include the negative LUC values).*
- ***RCP8.5*** *- Increasing emissions over time leading to very high GHG concentration levels and radiative forcing of 8.5 W/m2 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% of the total contributing emissions, and 97.8% of the total* CO_2 *emissions are attributable to fossil fuel use. Given the recent and ongoing developments occurring globally, including market forces that are driving demand for sustainable energy solutions, public policy advancements (e.g., 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.*

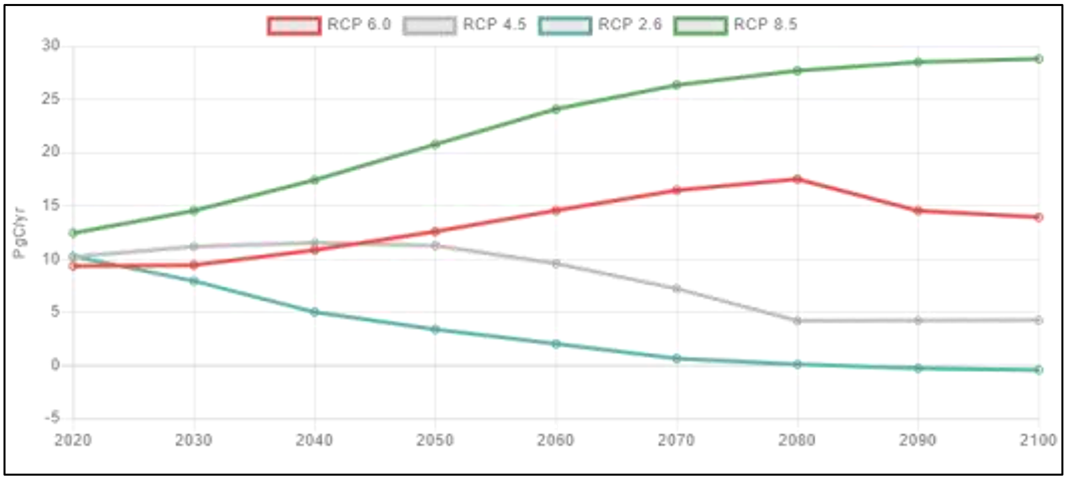


Figure 7 - RCP Projections – CO_2 Emissions (total)

Report Year Atmospheric GHG Concentrations: CO_2 (ppm) = 409.8, CH_4 (ppb) = 1858.4, N_2O (ppb) = 331.9

Current carbon dioxide concentrations are tracking at the lower end of the RCP data range relative to the 2020 year projections. However, the CH_4 and N_20) concentrations are closer to the upper end of the RCP range on the same relative basis.

Fossil Fuel Emissions Projections

There are a variety of ways to project emissions forward in time for the purpose of analysis. The availability of data, the projection time frame, and the nature of the action itself will often dictate the appropriate methodology (and corresponding assumptions) to be used. For example, reasonably foreseeable development scenarios (RFDs) have been prepared by the BLM Reservoir Group to try to forecast oil and gas growth in specific BLM field offices for a known basin or play based on a number of factors (estimated hydrocarbon potential, operator surveys, existing development trends, economic forecasts, basic geology, etc.). These documents typically provide for 20+ years of estimated oil and gas development and have traditionally been used to inform resource management plan development (as assumptions for analysis). The RFD documents are not intended to be a resolute prediction of development pace, or indicative of any potential development limit. Given the dynamics of the industry and the global nature of the hydrocarbon commodities markets, development in any single area does not exist in a vacuum and is subject to external influences that can render the best RFD outdated within a few years. As such, the BLM air resource specialists often find that these documents are unreliable predictors for the purposes of one-off impacts assessments and for determining prescriptive mitigation requirements over the entirety of a field office planning period. In more recent years, many of the specialists have been advocating for adaptive management based on iterative analyses of near real-time environmental factors, including emissions profile changes that are not reasonably foreseeable in more traditional planning assessments.

For the purposes of this report, the BLM is opting to provide two methods for projecting future GHG emissions based on a combination of internal statistics and the fossil fuel energy projections made by the EIA for its Annual Energy Outlook (AEO) report. Both methods rely on 5-year average datasets (presented above and below) to smooth out potential annual variability that can arise for any number of reasons, not least of which the simple economics of energy supply and demand over any given period.

The first method uses the AEO projections for energy production across the nation to project forward the 5-year average trends for federal production and emissions outlined in Section 4.0. The major assumption of this scenario being that the ratio of federal and non-federal mineral production is fixed relative to the 5-year average going forward. The AEO explores a number of different energy projection scenarios, out to year 2050 based on varying assumptions about the economy, technology, and policy. The Reference case is the baseline scenario from which all other side case estimates are made. The Reference case examines a future where slower growth in consumption (energy efficiency increases in the U.S. economy) is contrasted with an increasing energy supply due to technological progress in renewable energy, oil, and natural gas. The combination of the federal trend data and AEO scenarios provide for a longer term reasonably foreseeable range of potential emissions given the known parameters (supply, demand, policy, technology, etc.) that exist today and potential alternative policies that would change the evolution of energy dynamics going forward. For the 2020 AEO, the High Economic Growth and High Oil Price scenarios produce the highest emissions per region depending on their resource mix. Regions with lower coal production see higher emissions from the High Oil Price scenario, while other states with a relatively modest mix of resource production see maximums from the High Economic Growth scenario (also highest for total federal). For all regions the $35 Carbon Fee case provides the lowest emissions.

The below AEO scenario shown is the reference scenario. The interactive version of this report provides a selection field with other economic and growth scenarios to view the projected emissions data from total U.S. fossil fuel production. Cumulative totals (i.e., sums for the entire projection period) of federal emissions from direct and indirect GHG sources (as CO_2e) for the selected scenario and region are presented in the interactive version of the chart.

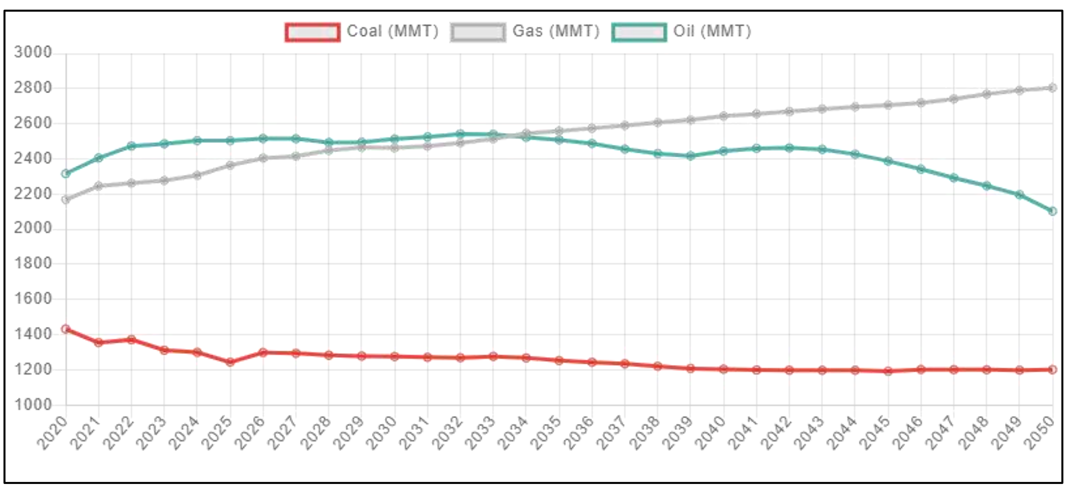


Figure 8 - U.S. Total (federal and non-federal) AEO Projected Emissions (REF2020)

Reference Scenario Emissions (MMT): U.S. Total = 193,014.36 Federal = 27,280.65

Projected Reference Scenario Emissions (MMT CO_2e) for Colorado, New Mexico, Utah, and Wyoming

	Colorado	New Mexico	Utah	Wyoming
Coal	594.75	242.09	607.78	13,515.11
Gas	1,361.58	1,831.00	418.5	2,958.82
Oil	110.92	2,115.42	179.93	832.85
Total	2,067.25	4,188.51	1,206.21	17,306.78

Abbreviations

AGGI Annual Greenhouse Gas Index

AR5 Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change

Bbl barrels

BLM Bureau of Land Management

Btu British thermal units

CF cubic feet

CFR Code of Federal Regulations

CH4 methane

CO2 carbon dioxide

EPA U.S. Environmental Protection Agency

GHG greenhouse gas

Gt gigatons

GtCO2e gigatons of equivalent carbon dioxide

GWPs global warming potential

Kg kilogram

Mcf million cubic feet

N2O nitrous oxide

ppb parts per billion

ppm parts per million

Ppmv parts per million volume

RCP representative concentration pathways

Scf standard cubic foot

W/m2 watt per square meter

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APPENDIX E

Specialist Report on Mercury and Selenium Deposition and Federally Listed Fish

Effects of Mercury and Selenium Deposition on Endangered Colorado River Basin Fish Species

LILA CANYON MINE LEASE MODIFICATIONS

DECEMBER 2020

PREPARED FOR

Bureau of Land Management

PREPARED BY

SWCA Environmental Consultants

EFFECTS OF MERCURY AND SELENIUM DEPOSITION ON ENDANGERED COLORADO RIVER BASIN FISH SPECIES

Prepared for

Bureau of Land Management
Price Field Office
125 South 600 West
Price, Utah 84501
(435) 636-3600
Attn: Dana Truman, Assistant Field Manager - Resources

Prepared by

SWCA Environmental Consultants
257 East 200 South, Suite 200
Salt Lake City, Utah 84111
(801) 322-4307
www.swca.com

December 2020

Contents

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CHAPTER 1. INTRODUCTION

Four species of endangered fish in the Upper Colorado River Basin may be indirectly impacted from the combustion of coal at local power generation stations. Combustion of coal releases mercury and selenium into the atmosphere, which may be directly deposited into habitat for the Colorado River fish, or onto adjacent land and subsequently washed into the river. Mercury and selenium are ubiquitous contaminants affecting freshwater environments on a global scale (Day et al. 2020). This report addresses the effects to the four endangered fish and their critical habitat from contaminants released from coal combustion. This report is provided to support the Bureau of Land Management (BLM) Lila Canyon Mine Lease Modifications Environmental Assessment (EA) and the informal consultation process between the BLM and the U.S. Fish and Wildlife Service (USFWS) to determine the potential for effects as a result of the project to Colorado River fish protected under the Endangered Species Act.

1.1 Project Description

The BLM Price Field Office proposes to offer two Lila Canyon coal lease modification areas (LMAs) for lease to the Lila Canyon Mine lessee. The Lila Canyon Mine (Mine) is an underground coal mine approximately 9 miles southeast of East Carbon in Emery County, Utah. The LMAs are located in the Book Cliffs coal field. The two LMAs, if approved, would add collectively 1,272.64 acres to the Mine lessee’s Federal coal leases and would be mined by underground methods (the project). The BLM estimates that there are approximately 7.2 million tons of salable coal in these two areas, which are projected to extend the life of the Mine by approximately 2 to 3 years. With this extension, however, the annual coal production limit will not increase unless the Mine lessee applies for and receives a production limit increase from the Utah Division of Air Quality.

The BLM prepared the Lila Canyon Mine Lease Modifications EA (DOI-BLM-UT-G020-2018-0039-EA) to analyze the environmental effects of leasing the LMAs, including their development under a conceptual mine plan. The Mine and Lila Canyon portals are located in T. 16 S., R. 14 E., secs. 10 thru 15 and secs. 22 thru 26, and T. 16 S., R. 15 E., secs. 19 and 30 (see EA Figure 2). The existing Mine development was approved by the Utah Division of Oil, Gas and Mining (DOGM) in 2007 as an extension to the Horse Canyon Mine. The current DOGM permit area (DOGM Permit No. C/007/0013) encompasses 4,663.6 acres. Since 2007, all coal reserves have been accessed through the Lila Canyon portals, and the Lila Canyon Mine lessee would continue to use these portals to access reserves in the LMAs.

CHAPTER 2. SETTING

The LMAs are in rugged, mountainous terrain along the western flanks of the Book Cliffs escarpment, which rises abruptly above the valley floor. The Mine and the LMAs are in the Price River drainage. To the east of the LMAs is the Turtle Canyon Wilderness Area and the steep mountainous areas that are part of the Range Creek drainage. To the west is rolling lowland topography on the highly erodible Mancos Shale that occupies the Price River valley. Elevations in the LMAs range from approximately 8,113 to 6,800 feet above mean sea level. Characteristic vegetation in this area of the Book Cliffs includes Douglas fir (*Pseudotsuga menziesii*) at the highest elevations, pinyon-juniper forests over most of the bench areas, and a mixture of shrubs and grasses in the low areas (BLM 2000).

The closest coal-loading terminal (unit-train) is the Savage Brothers–owned Savage Coal Terminal between Wellington and Price, Utah, on the mainline of the Union Pacific Railroad, at a haul distance of approximately 32 miles. It is another 12 miles to the Wildcat Unit-Train Loadout, located on the Utah Railway near Helper, Utah. Most of the coal produced at the Lila Canyon Mine is currently shipped to the Hunter Power Plant in Castle Dale and Huntington Power Plant in Huntington, both in northwestern Emery County, Utah.

2.1 Coal-Fired Power Plants

The Hunter and Huntington Power Plants are permitted by the Utah Division of Air Quality under Title V permits; both plants were originally constructed in the 1970s. The Hunter Power Plant, approximately 37 miles (60 kilometers [km]) west-southwest of the LMAs, is a Phase II Acid Rain source and is a major source for SO_2, NOx, PM_{10}, CO, VOC, HAP, HCl, and GHG (UDAQ 2020a). The Huntington Power Plant, approximately 36.5 miles (59 km) west of the LMAs is a Phase II Acid Rain source and is a major source of SO2, NOx, PM10, CO, HAP, HF, and HCl emissions (UDAQ 2020b).

On December 16, 2011, the Environmental Protection Agency (EPA) finalized the first national standards to reduce mercury and other toxic air pollutants from coal- and oil-fired power plants. The Mercury and Air Toxics Standards (MATS) provide regulatory certainty for power plants and levels the playing field so that both new and older plants have to limit their emissions of mercury. The final rule establishes power plant emission standards for mercury, acid gases, and nonmercury metallic toxic pollutants, which is expected to result in preventing about 90% of the mercury in coal burned in power plants from being emitted to the air.

Indirect Emissions of Mercury

Although worst-case (4.5 million tons per year) combustion emissions are presented in the Lila Canyon Mine Lease Modifications EA Table 3-10, the actual mercury emissions can vary based on the quality and characteristics of the coal as well as the control strategies and equipment utilized at the final combustion location. The Mine currently provides regional Utah power plants (e.g., Hunter Power Plant and Huntington Power Plant) with approximately 2% to 7% (U.S. Energy Information Administration 2018) of the total tonnage of coal combusted at the plants annually. If approximately 6.4 million tons of coal are combusted annually at Hunter and Huntington Power Plants, 2 to 7% would represent approximately 128,000 to 447,000 tons of coal. This is 10% or less of the maximum amount of 4.5 million tons of coal that is permitted to be mined annually at the Lila Canyon Mine. If all 4.5 million tons of coal mined annually is transported to a regional coal-fired power plant to be combusted, it would represent approximately 70% of the approximately average annual 6.4 million tons of coal combusted at these plants. Assuming all 4.5 million tons of coal is combusted at Hunter and Huntington Power Plants would provide the maximum potential emissions of mercury that could occur in the airshed.

In 2019, the Hunter and Huntington Power Plants provided actual mercury emissions from all on-site sources via the EPA's Toxic Release Inventory (TRI) program (EPA 2020). The TRI tracks the release of certain toxic chemicals that may pose a threat to human health and the environment. U.S. facilities in different industry sectors must report annually how much of each chemical is released to the environment and/or managed through recycling, energy recovery, and treatment. The total reported mercury emissions to the atmosphere from fugitive and stack sources at Hunter and Huntington Power Plants in 2019 was 5.9 pounds (lbs). Mercury emissions from the combustion of 4.5 million tons of coal annual from the Federal coal lease tract would be approximately 70% of emissions from Hunter and Huntington, or 4.1 lbs. These emissions are 0.2% of the 1,680 lbs (0.84 tons/year) estimated for a generic power plant without emissions controls (see EA Table 3-10). Emissions controls implemented to comply with MATS are the likely reason why emissions are lower at Hunter and Huntington as opposed to the combustion of coal at a generic power plant.

Based on data available from the TRI data explorer, the total emissions in Utah from industrial and electrical generation sectors is 770 lbs of mercury emissions for reporting year 2019. The estimated mercury emissions (4.1 lbs) from Federal coal lease tracts represent approximately 0.5% of the state's total mercury emissions. Additionally, emissions from Hunter and Huntington Power Plants will continue to occur independent of which alternative is selected. Summarily the mercury emissions from the combustion of coal from the Federal lease tract are minimal as they are a small fraction of overall emissions in the state and would not result in an increase to existing or foreseeable emissions as the power plants would continue to operate without the Federal coal.

When mercury released by the combustion of coal is deposited on land and water, it accumulates in the food chain and can be toxic to fish, wildlife, and humans. Mercury released into the atmosphere by the combustion of coal mined from the Federal coal lease tract could be deposited and accumulate in hydrological systems, potentially affecting fish, wildlife, and humans. The BLM is not aware of site-specific mercury studies for the Hunter or Huntington Power Plants. To help inform the decision the BLM incorporates by reference the results from a mercury deposition analysis conducted by the Electric Power Research Institute (EPRI) (EPRI 2017) for the Craig Generating Station in northwestern Colorado.

The objective of the EPRI study was to determine the relative contributions of mercury emissions from local power plants and from global, regional, and other local sources to mercury deposition in the Yampa and White River Basin. The Yampa and White rivers feed into the Green River, which joins the Colorado River downstream. Mercury is a global pollutant and may undergo atmospheric transport over both short and very long (intercontinental) distances depending on its chemical form. Results of the EPRI study show that natural and non-U.S. sources of mercury were the largest contributors to mercury deposition in the modeling domain. Emissions from the Craig Generating Station accounted for 0.2% of deposition and other local power plants contributed 0.8%. For comparison, in a similar study the EPRI prepared for the Four Corners region (the San Juan River Basin project), the local scale power plants contributed 2% or less of the atmospheric mercury deposition (EPRI 2015, 2016). Mercury emissions from the Craig Generating Station used in the EPRI study were 44.2 lbs/year. Emissions from Hunter and Huntington Power Plants (5.9 lbs/year) is 13% of the emissions from the Craig Generating Station. Emissions from the Federal coal lease (4.1 lbs/year) would be 9.3% of the emissions evaluated in the EPRI study. From this information it is estimated that mercury emissions from Hunter and Huntington Power Plants likely contribute less than 1% to total mercury deposition in in the local airshed and river basins, and as a result the Federal coal lease will have a minimal contribution to overall mercury deposition in the area.

Ultimately, mercury emissions associated with coal combustion sources are evaluated as part of the permitting process or rule implementation (Best Available Retrofit Technology [BART], MATS, etc.) from their respective regulatory agencies (state or EPA). To be clear, all coal-fired power plants are required to have an operating permit (Title V) for any criteria pollutant for which the facility has a potential to emit greater than 100 tons per year. Both Hunter and Huntington Power Plants have obtained Title V operating permits which include conditions limiting mercury emissions. The permitting rule-making process has ample opportunity for public involvement, and the public may also petition EPA for review and remand of the permit after the state has issued it. No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act (NEPA) of 1969 (15 United States Code 793(c)(1). Given that courts have consistently recognized that Clean Air Act actions, which themselves are exempt from NEPA requirements,[6] are in fact the functional equivalent of NEPA, it is appropriate for the BLM to rely on those permitting procedures enacted by the state and overseen by the EPA as a basis for asserting that the indirect combustion impacts of the coal lease modification action have already been adequately disclosed and analyzed. Further, because that process provided for meaningful public involvement it need not be readdressed here. Given the rigorous review the combustion facilities receive to emit regulated pollutants it is exceedingly improbable that combusting the lease modification coal would cause or contribute to the likeliness, frequency, or increasing severity of any detrimental impacts to air quality, including mercury deposition, in areas around or downwind of any potential coal combustion facility.

2.2 Endangered Colorado River Fish

Four species of fish listed as endangered under the Endangered Species Act are commonly referred to as the Colorado River fish and consist of the Colorado pikeminnow (*Ptychocheilus lucius*), razorback sucker (*Xyrauchen texanus*), humpback chub (*Gila cypha*), and bonytail (*Gila elegans*). They are historically found in the Colorado River and its tributaries.

2.2.1 Colorado Pikeminnow

The Colorado pikeminnow is endemic to the Colorado River Basin, where it was once widespread and abundant in warm-water rivers and tributaries. Wild populations of Colorado pikeminnow are now found only in the Upper Basin of the Colorado River (above Lake Powell). Three wild populations of Colorado pikeminnow are found in 1,090 miles (1,754 km) of riverine habitat in the Green River, upper Colorado River, and San Juan River subbasins. It thrives in swift-flowing muddy rivers with quiet, warm backwaters and is primarily piscivorous, but smaller individuals also eat insects and other invertebrates. These fish spawn between late June and early September and when they are 5 to 6 years old and at least 16 inches long. Spawning occurs over riffle areas with gravel or cobble substrate. The eggs are randomly splayed onto the bottom and usually hatch in less than 1 week. The USFWS designated six reaches of the Colorado River System as critical habitat for the Colorado pikeminnow on March 21, 1994 (59 *Federal Register* 13374). Designated critical habitat makes up about 29% of the species' historic range and occurs exclusively in the Upper Colorado River Basin. Portions of the Colorado, Gunnison, Green, Yampa, White, and San Juan Rivers are designated critical habitat.

[6] Section 7(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 United States Code 793(c)(1)) exempts actions under the Clean Air Act from the requirements of NEPA.

The primary threats to Colorado pikeminnow populations are competition with and predation by nonnative fish species, streamflow regulation and habitat modification (including cold-water dam releases, habitat loss, and blockage of migration corridors), and pesticides and pollutants. Predation or competition by nonnative fish species is identified as a primary threat to the continued existence or the re-establishment of self-sustaining populations of Colorado pikeminnow and the other three endangered Colorado River fish. Nonnative fishes compete with native fishes through predation, habitat degradation, competition for resources, hybridization, or disease transmission.

Threats from pesticides and pollutants include accidental spills of petroleum products and hazardous materials; discharge of pollutants from uranium mill tailings; and high selenium concentration in the water and food chain (USFWS 2002a). Mercury may pose a significant threat to Colorado pikeminnow populations of the Upper Colorado River Basin. The magnitude of the threat from mercury and selenium is in need of further investigation.

2.2.2 Razorback Sucker

The razorback sucker is the largest native sucker to the western United States, found in deep, clear to turbid waters of large rivers and some reservoirs over mud, sand, or gravel, and like most suckers, feeds on both plant and animal matter. Razorback suckers can spawn as early as age three or four, when they are 14 or more inches long. Breeding males turn black up the lateral line, with brilliant orange extending across the belly. Depending on water temperature, spawning can take place as early as November or as late as June. In the Upper Colorado River Basin, razorbacks typically spawn between mid-April and mid-June. The species is being reintroduced into the Green, Gunnison, upper Colorado and San Juan Rivers, Lakes Mojave and Havasu, and the lower Colorado and Verde Rivers.

The USFWS designated 15 reaches of the Colorado river system as critical habitat for the razorback sucker. Designated critical habitat makes up about 49% of the species' original range and occurs in both the Upper and Lower Colorado River Basins. In the Upper Basin, critical habitat is designated for portions of the Green, Yampa, Duchesne, Colorado, White, Gunnison, and San Juan Rivers.

Population numbers of the razorback sucker were extremely low in the early part of the 2000s. The wild population consisted of primarily aging adults; no young razorback suckers had been captured in the Upper Colorado River since the mid-1960s (USFWS 2002b).

Because of the low numbers of wild fish, the Recovery Program has been rebuilding razorback sucker populations in the Upper Colorado River Basin with hatchery stocks. Stocking continues in the Green, Colorado, and San Juan River subbasins, and reproduction is occurring and increasing. In 2018, the USFWS recommended the razorback sucker be reclassified from endangered to threatened.

The primary threats to razorback sucker populations are streamflow regulation and habitat modification (including cold-water dam releases, habitat loss, and blockage of migration corridors); competition with and predation by nonnative fish species; and pesticides and pollutants (USFWS 2002b). Nonnative species are a major cause for the lack of recruitment and are the most important biological threat to the razorback sucker. Threats to the razorback sucker from nonnative fish are similar to those facing the Colorado pikeminnow.

Historic selenium contamination of the Upper and Lower Colorado River Basins has likely contributed to the decline of these endangered fish by affecting their overall reproductive success, including loss of eggs and larvae. Selenium concentrations in whole-body fish in the Colorado River Basin have been among the highest in the nation (Hamilton 1999). Although selenium has been more the focus of contaminants research involving razorback sucker, mercury could also pose a threat at elevated concentrations. Because the razorback sucker is not a top predator, as the Colorado pikeminnow is, mercury bioaccumulation poses less of a problem for this species. The magnitude of the threat from mercury and selenium is in need of further investigation.

2.2.3 Humpback Chub

Adult humpback chubs are dark on top and light below and fins may have yellow-orange pigment near the base. Adults usually range from 12 to 16 inches long and weigh 0.75 to 2 lbs. This species historically occurred in the mainstream Colorado River in slower eddies and pools downstream below Hoover Dam; however, present populations are restricted to areas in, and upstream, of the Grand Canyon.

Historic distribution research indicates the species inhabited canyons of the Colorado River and four of its tributaries: the Green, Yampa, White, and Little Colorado Rivers. Presently the species occupies about 68% of its historical habitat. Humpback chub move substantially less than other native Colorado River fishes, showing high fidelity to canyon reaches characterized by deep water, swift currents, and rocky substrate.

In the Upper Colorado River Basin, the two most stable humpback chub populations are found near the Colorado/Utah border: one at Westwater Canyon in Utah; and one in an area called Black Rocks, in Colorado. Smaller numbers in the Upper Basin were found in the Yampa and Green Rivers in Dinosaur National Monument, Desolation and Grey Canyons on the Green River in Utah, and Cataract Canyon on the Colorado River in Utah.

The primary threats to humpback chub are streamflow regulation, habitat modification, predation by nonnative fish species, parasitism, hybridization with other native *Gila* species, and pesticides and pollutants (USFWS 2002c). The threats to the humpback chub from nonnative fish are similar to those facing the Colorado pikeminnow, posing a challenge to recovery. Contaminants, including mercury and selenium, may pose a lesser threat as well, but the magnitude of this threat is in need of further investigation.

The USFWS has completed a species status assessment and a 5-year status review that concluded the current risk of extinction for the humpback chub is low, as populations are stable, persisting without the need for hatchery stocking. In 2018, the USFWS recommended the humpback chub be reclassified from endangered to threatened.

2.2.4 Bonytail

The bonytail is a highly streamlined fish often appearing dark in clear water and pale in more turbid waters. It prefers eddies and pools and is not often found in swift currents. This is the rarest of the four endangered Colorado River fish species and wild populations no longer exist upstream of Lake Powell. Individuals may reach 22 inches in length and live 50 years. Bonytail feed on insects, plankton, and plant matter. The species is being reintroduced into the Green, and upper Colorado rivers, Lakes Mojave and Havasu, and the lower Colorado River to Yuma, Arizona.

USFWS designated seven reaches of the Colorado River as critical habitat for the bonytail. Portions of the Green, Yampa, and Colorado Rivers are designated as critical habitat, representing about 14% of the species' historic range.

Bonytail are so rare that it is currently not possible to conduct population estimates. In response to the low abundance of individuals, the Recovery Program is implementing a stocking program to re-establish populations in the Upper Basin. Most stocked bonytail do not appear to survive very long after release into a given river. Researchers continue to experiment with prerelease conditioning and exploring alternative release sites to improve their survival. An increasing number of bonytail have been detected at several locations throughout the Upper Colorado River Basin.

The primary threats to bonytail populations are streamflow regulation and habitat modification (including cold-water dam releases, habitat loss, and blockage of migration corridors); competition with and predation by nonnative fish species; hybridization; and pesticides and pollutants (USFWS 2002d). The threats to the bonytail from nonnative fish are similar to those facing the Colorado pikeminnow.

2.2.5 Critical Habitat

Critical habitat for all four endangered fish was designated in 1994 (59 *Federal Register* 13374). The critical habitat for the four Colorado River fish species all contain the primary constituent elements (PCEs) that are required to be present and are determined to be necessary for the survival and recovery of the species. All four species' critical habitat contains the following PCEs (50 Code of Federal Regulations 13378):

1. Water: this includes a quantity of water of sufficient quality (i.e., temperature, dissolved oxygen, lack of contaminants, nutrients, turbidity, etc.) that is delivered to a specific location in accordance with a hydrologic regime that is required for the particular life stage for each species.

2. Physical habitat: this includes areas of the Colorado River system that are inhabited or potentially habitable by fish for use in spawning, nursery, feeding, and rearing, or corridors between these areas. In addition to river channels, these areas also include bottom lands, side channels, secondary channels, oxbows, backwaters, and other areas in the 100-year floodplain, which, when inundated, provide spawning, nursery, feeding and rearing habitats, or access to these habitats.

3. Biological environment: food supply, predation, and competition are important elements of the biological environment and are considered components of this constituent element. Food supply is a function of nutrient supply, productivity, and availability to each life stage of the species. Predation and competition, although considered normal components of this environment, are out of balance due to introduced nonnative fish species in many areas.

CHAPTER 3. EFFECTS OF MERCURY AND SELENIUM

3.1 Mercury

The Colorado River fish may be indirectly impacted from the combustion of coal at local power generation stations. Combustion of coal releases mercury into the atmosphere which may be deposited into habitat for the Colorado River fish directly, or onto adjacent land and subsequently washed into the river.

Mercury is a concern primarily to longer-lived fish species (e.g., Colorado pikeminnow) because it bioaccumulates within the tissue of individuals. Therefore, the longer an individual lives and absorbs mercury, the higher the levels within their tissues over time. Mercury can affect an individual’s central nervous system, alter their behaviors (e.g., reduced predator avoidance), and disrupt the endocrine system resulting in reduced reproductive success (Lusk 2010). Although the specific effects of mercury and other heavy metals on pikeminnow are known, the role these contaminants play on suppressing populations of the Colorado River fish are not well understood (USFWS 2011a).

Mercury contamination is a widespread problem across the United States. The vast majority of health advisories issued by the EPA for the consumption of fish from lakes and reservoirs are due to mercury, PCBs, dioxins and furans, DDT, and chlordane. Of those, mercury is the most commonly detected. Of predacious fish sampled in 2008, 48.8% of the sampled population of lakes across the country had mercury tissue concentrations that exceeded the 0/3 micrograms per gram (parts per million) human health screening value for mercury, which represented a total of 36,422 lakes (EPA 2009).

The harmful effects of methylmercury on fish populations at existing exposure levels in many North American freshwaters would be sublethal, such as cellular damage, reduced vigor, and reduced reproduction. Direct mortality due to methylmercury has been observed only at high concentrations (Sandheinrich and Wiener 2011).

Rather than direct mortality, it is expected that chronic toxicity from exposure to mercury in the action area may be affecting the endangered fish. Chronic toxicity is the development of negative effects as the result of long-term exposure to a toxicant or other stressor. It can manifest as direct lethality but more commonly refers to sublethal endpoints such as decreased growth, reduced reproduction, or behavioral changes such as impacted swimming performance.

It is known that combustion of coal is releasing mercury into the area and estimates of quantity are known at various sources. It is not known specifically, however, what proportion of that mercury deposits within the analysis area, or the Colorado River Basin watershed, or is transported to distant locations beyond the limits of the local watersheds. Although not fully understood or quantified, it is believed that the primary impact from coal combustion to the Colorado River fish is from the emission and subsequent deposition of mercury and eventual integration into fish tissue. Mercury poses a greater threat to the Colorado pikeminnow, as compared to the other endangered fish in the Colorado River Basin. In the Upper Colorado River Basin, elevated levels of mercury were found in tissue samples of only 13% of the 2,324 individual fish that were sampled from seven major tributaries to the Colorado River in a retrospective study of selenium and mercury in fish tissues gathered over 50 years (1962–2011)

(Day et al. 2020). Of the 17 species of fish sampled, Colorado Pikeminnow most frequently had the highest levels of mercury.

Mercury from the combustion of coal that is deposited either on land or water surfaces in the analysis area has the potential to affect the designated critical habitat for these species. This would occur primarily by increasing the amount of contaminates present in those areas (PCE No. 1). It is difficult to quantify the level of this impact to critical habitats given the lack of information on where the mercury in the analysis area originates from. As stated in Section 2.1, the mercury emissions from the Mine LMAs (4.1 lbs/year) as a portion of coal burned at the Hunter and Huntington Power Plants would likely contribute less than 1% to total mercury deposition in in the local airshed and river basins. The leasing of the LMAs would contribute minimally to overall mercury deposition in the area.

When added to the other regional and global sources of mercury being deposited into the Colorado River system and the mercury already within the system, additional mercury may result in impacts to critical habitat through a reduction in water quality but would not be likely to adversely affect habitat to a point that it no longer provides water of sufficient quality essential for the conservation of the Colorado River fish species.

3.1.1 Colorado Pikeminnow

The Colorado pikeminnow is expected to be at the greatest risk from exposure to mercury. Colorado pikeminnow have a higher likelihood of bioaccumulating mercury. Predatory organisms at the top of the food web generally have higher mercury concentrations in their bodies because mercury tends to biomagnify up through the food chain and concentrate in upper trophic levels (EPA 1997). The Colorado pikeminnow is a top predator. The Colorado pikeminnow is also a long-lived fish, living 55 years or more (Osmundson et al. 1997). Thus, mercury will accumulate more rapidly and over a longer period of time than in the other three endangered fish species.

Based on studies of mercury concentrations in Colorado pikeminnow over time, it is expected that some Colorado pikeminnow in the action area may already be experiencing chronic, sublethal harmful effects from elevated mercury concentrations. It should be noted, however, that piscivorous fish living in fresh waters in the midwestern and eastern United States and in some waters in the western United States contaminated by mining activities, have been reported to contain harmful levels of mercury in muscle tissue (Sandheinrich and Wiener 2011). Thus, harmful effects to predatory fish from mercury are not isolated to this action area but are part of a geographically widespread problem.

Given that fish tissue mercury concentrations have been determined to be elevated in Colorado pikeminnow, and coal mining and local combustion add mercury to the system, this additional mercury adds to any negative effects resulting from mercury exposure. Based on best available science, it is believed some Colorado pikeminnow individuals are experiencing low, chronic negative health effects from mercury already in the action area. The mercury added by this project will add to the effects of the chronic condition, although the relative contribution of project-related mercury is assumed to be a very small percentage of the total mercury that has been and will continue to be deposited in the analysis area.

Despite the chronic, low-level harmful effects of mercury that Colorado pikeminnow are likely experiencing, it is believed that the populations decline seen in Colorado pikeminnow over the past decade or more is primarily a result of increased nonnative fish species.

Although some Colorado pikeminnow individuals are likely experiencing low-level harmful effects from existing mercury in the system, it is not believed that the additional amount of mercury from the project would be enough to significantly or measurably reduce population numbers, reproduction, or constrain Colorado pikeminnow distribution.

3.1.2 Razorback Sucker

The effects to the razorback sucker from project-generated mercury are similar to those described for the Colorado pikeminnow above, although likely to be less severe in the analysis area. The razorback sucker is not a piscivorous fish and would not bioaccumulate mercury as rapidly as the Colorado pikeminnow. As with the Colorado pikeminnow, it is believed nonnative species are the primary limiting factor for razorback sucker numbers, successful recruitment, and their distribution. Although the evidence indicates that some razorback sucker individuals are likely being adversely affected by mercury in the system, evidence does not indicate that the negative effects from mercury rise to the level of reducing population numbers, are limiting reproduction, or are constraining razorback sucker distribution.

3.1.3 Humpback Chub

The effects to the humpback chub in the action area from project-generated mercury are similar to those described for the Colorado pikeminnow above, although perhaps less severe. The humpback chub is not a top predator and may not bioaccumulate mercury as rapidly as the Colorado pikeminnow. As with the Colorado pikeminnow, it is believed nonnative species are the primary limiting factor for humpback chub numbers, successful recruitment, and their distribution. Although the evidence indicates that some humpback chub individuals are likely being adversely affected by mercury in the system, evidence does not indicate that the negative effects from mercury rise to the level of reducing population numbers, are limiting reproduction, or are constraining humpback chub distribution.

3.1.4 Bonytail

The effects to the Bonytail in the action area from project-generated mercury are similar to those described for the Colorado pikeminnow above, although perhaps less severe. The bonytail is not a top predator and may not bioaccumulate mercury as rapidly as the Colorado pikeminnow. As with the Colorado pikeminnow, it is believed nonnative species are the primary limiting factor for bonytail numbers, successful recruitment, and their distribution. Although the evidence indicates that some bonytail individuals are likely being adversely affected by existing mercury in the system, evidence does not indicate that the negative effects from mercury rise to the level of reducing population numbers, are limiting reproduction, or are constraining bonytail distribution.

3.2 Selenium

In addition to mercury, indirect impacts to the Colorado River fish from increases in selenium could occur from the combustion of coal at the Hunter and Huntington Power Plants. However, the EPA's TRI shows no reported selenium emissions at Hunter and Huntington Power Plants (EPA 2020). Selenium, a trace element, is a natural component of coal and soils in the area and can be released to the environment by the irrigation of selenium-rich soils and the burning of coal in power plants with subsequent emissions to air and deposition to land and surface water. Contributions from anthropogenic sources have increased with the increases of world population, energy demand, and expansion of irrigated agriculture. Selenium, abundant in western soils, enters surface waters through erosion, leaching, and runoff. Although required in the diet of fish at very low concentrations (0.1ug/g) (Sharma and Singh 1984), it is unknown if selenium is adversely affecting Colorado River fish. Dietary selenium is the primary source for selenium in fish (Lemly 1993); selenium in water is less important than dietary exposure when determining the potential for chronic effects to a species (EPA 1998).

Excess selenium in fish has been shown to have a wide range of adverse effects, including mortality, reproductive impairment, effects on growth, and developmental and teratogenic effects, including edema and finfold, craniofacial, and skeletal deformities (Lemly 2002). Excess dietary selenium causes elevated selenium concentrations to be deposited into developing eggs, particularly the yolk (Buhl and Hamilton 2000). If concentrations in the egg are sufficiently high, developing proteins and enzymes become dysfunctional or result in oxidative stress, conditions that may lead to embryo mortality, deformed embryos, or embryos that may be at higher risk for mortality.

Of the four Colorado river fish species, selenium would disproportionately affect the razorback sucker more than the other three species. As with all sucker species, the razorback sucker is a bottom feeder and more likely to ingest selenium that has precipitated to the river bottoms. In the Upper Colorado River Basin, elevated levels of selenium have been found in tissue samples of 48% of the fish that were sampled (Day et al. 2020).

Impacts to critical habitat from selenium added to the system through coal combustion, together with selenium in the system from other sources, may affect critical habitat for the endangered fish; however, the project would not diminish water quality to a point where critical habitat can no longer provide the physical and biological features essential for the conservation of the endangered Colorado River fish species.

3.2.1 Colorado Pikeminnow

Given that water concentrations are generally below the chronic standard, there are no recent data indicating that there is immediate cause for alarm. It is believed nonnative species are the primary limiting factor for Colorado pikeminnow numbers, successful recruitment, and their distribution. Although further sampling and testing for selenium is warranted, evidence does not indicate that potential effects from selenium rise to the level of reducing population numbers, are limiting reproduction, or are constraining Colorado pikeminnow.

3.2.2 Razorback Sucker

Given that water concentrations are generally below the chronic standard, there are no recent data indicating that there is immediate cause for alarm. It is believed nonnative species are the primary limiting factor for razorback sucker numbers, successful recruitment, and their distribution. Although further sampling and testing for selenium is warranted, evidence does not indicate that potential effects from selenium rise to the level of reducing population numbers, are limiting reproduction, or are constraining razorback sucker.

3.2.3 Humpback Chub

Given that water concentrations are generally below the chronic standard, there are no recent data indicating that there is immediate cause for alarm. It is believed nonnative species are the primary limiting factor for humpback chub numbers, successful recruitment, and their distribution. Although further sampling and testing for selenium is warranted, evidence does not indicate that potential effects from selenium rise to the level of reducing population numbers, are limiting reproduction, or are constraining humpback chub.

3.2.4 Bonytail

Given that water concentrations are generally below the chronic standard, there are no recent data indicating that there is immediate cause for alarm. It is believed nonnative species are the primary limiting factor for bonytail numbers, successful recruitment, and their distribution. Although further sampling and testing for selenium is warranted, evidence does not indicate that potential effects from selenium rise to the level of reducing population numbers, are limiting reproduction, or are constraining bonytail.

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APPENDIX F

Public Comments on the Draft EA

Lila Canyon Mine Lease Modifications Environmental Assessment – Price Field Office – Responses to Public Comments

The Bureau of Land Management (BLM) Price Field Office shared its Lila Canyon Mine Lease Modifications Draft environmental assessment (EA) with the public on April 24, 2020 and offered a 30-day public comment period that was extended until June 8, 2020. The following table comprises the BLM Price Field Office's responses to all substantive comments received. Substantive comments do one or more of the following: 1) Question, with reasonable basis, the accuracy of information in the EA; 2) Question, with reasonable basis, the adequacy of the methodology or assumptions used for the EA; 3) Present new information relevant to the analysis; 4) Present reasonable alternatives other than those analyzed in the EA; and 5) Cause changes or revisions in one or more of the alternatives.

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Comment #	Commenter	Comment Topic	Comment	BLM Response
1	Emery County	Socio-Economic Impacts	The Estimated Employment Requirements in the EA states that: "Leasing the Lila Canyon proposed modification tracts would extend the life of the Mine, but neither the workforce of approximately 238 nor the annual production, which "shall not exceed 4.5 million tons per rolling 12-month period" (Utah Division of Air Quality [DAQ] 2013), would be expected to increase." Maintaining the current workforce is important to the area, as is the extended life of the mine. The EA should also recognize the economic benefit to the numerous support industries in the Carbon/Emery area, including the trucking industry. In addition, the taxes, revenues and royalties generated as a result of the lease modifications are several million dollars. Clearly, the continued operation and productivity of the Lila Canyon Mine is crucial for the economic viability of Emery and Carbon Counties. It is also crucial for the security of the local, regional and national energy network. These crucial issues cannot be overstated.	Comment acknowledged. The analysis in Section 3.3.3 of the EA describes the socioeconomic effect of secondary employment as well as taxes, revenues, and royalties. The BLM Price Field Office (PFO) Resource Management Plan (RMP) includes goals to provide opportunities for mineral extraction and development to support the need for domestic energy resources (EA Section 1.5).
2	Emery County	Dingell Act and WSA	No reference should be made to Turtle Canyon Wilderness Study Area. The John D. Dingell, Jr. Conservation, Management, and Recreation Act released lands not designated as wilderness from the wilderness study area. The release included the portion of the Turtle Canyon WSA which overlapped the proposed lease modifications. The proposed lease modifications are consistent with federal law and federal land management plans.	The Turtle Canyon Wilderness Study Area (WSA) was described to provide context for compliance with the PFO RMP, which was finalized in 2008 and includes the Turtle Canyon WSA. Management Decision WSA-7 provides for management of lands released from wilderness study (EA Section 1.5).
3	Joint NGO Letter (Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Montana Environmental Information Center, Natural Resources Defense Council, Sierra Club, Southern Utah Wilderness Alliance, Union of Concerned Scientists, WildEarth Guardians)	NEPA	NEPA directs agencies to fully and accurately analyze and disclose the potentially significant environmental, public health, and social welfare impacts of the proposed alternatives, and to contextualize that information for decision-makers and the public, in an environmental impact statement. NEPA requires a more searching analysis than merely disclosing the amount of pollution. Rather, BLM must examine the "ecological[,]… economic, [and] social" impacts of those emissions, including an assessment of their "significance."8 By failing to use available tools, such as the social cost of carbon, to analyze and disclose the potentially significant impacts of the greenhouse gas emissions resulting from the proposed action, BLM has violated NEPA.	Comment acknowledged. The preparation of this leasing EA was done in compliance with all federal statutes, regulations, and applicable policies. The BLM considered whether performing a SCC analysis would help inform the decision-maker and the public for this NEPA review, by disclosing meaningful information regarding the Proposed Action's potential impacts on GHG emissions and climate change. After careful consideration, the BLM determined this approach was not appropriate and instead favored a quantitative analysis of these potential impacts. See EA, Section 3.2.3.3. Specifically, the BLM rejected the SCC approach because 1) that approach, adopted in EO 12866 (58 Fed. Reg. 51,735 [October 4, 1993]), was originally intended to apply only to rulemaking, not project-specific NEPA analyses, like the one here; 2) this guidance has subsequently been withdrawn by EO13563 (76 Fed. Reg. 3821 [Jan. 18, 2011]); 3) NEPA does not require a cost-benefit analysis (40 CFR 1502.23); and 4) because the full social impacts of coal development have not been monetized, quantifying only the SCC without considering all other cost/benefits, and would skew the analysis and not be useful. The EA includes a robust analysis of direct and downstream GHG emissions and analyzed those emissions in the context of local, statewide, regional, national, and global projections, which provides the contextual understanding of relative impacts. The BLM approach in the EA meets the "hard look" requirement by presenting the environmental impacts of the proposal and the alternatives in comparative form (quantified greenhouse gas emissions), and discusses cumulative climate impacts, providing for the definition of issues and environmental consequences and ensuring that an informed decision can be made. In addition, the *Utah Bureau of Land Management Air Resource Management Strategy 2020 Monitoring Report* (BLM 2020b) describes GHG emissions from oil and gas wells and has been incorporated into the cumulative discussion. Appendix D has been added to the EA, which summarizes national and regional trends in energy production and emissions. Finally, an analysis of the cumulative effects was performed and considered potential climate change impacts at the state level based on future climate trends under a range of global GHG emissions scenarios known as the representative concentration pathways (RCP). Specifically, the USGS Climate Change Viewer was used to provide projections of future climate trends under low (RCP4.5) and aggressive (RCP8.5) emission scenarios. See EA, Section 3.2.3.6.

Comment #	Commenter	Comment Topic	Comment	BLM Response
4	Joint NGO Letter	Climate Change	Even in combination with a general, qualitative discussion of climate change, by calculating only the tons of greenhouse gases emitted, an agency fails to meaningfully assess and disclose the potentially significant incremental impacts to property, human health, productivity, and so forth. An agency therefore falls short of its legal obligations and statutory objectives by disclosing only volume estimates. To take an analogous example, courts have held that just quantifying the acres of timber to be harvested or the miles of road to be constructed does not constitute a "description of actual environmental effects," even when paired with a qualitative "list of environmental concerns such as air quality, water quality, and endangered species," when the agency fails to assess "the degree that each factor will be impacted." By monetizing climate damages using the social cost of greenhouse gas metrics, BLM can help satisfy NEPA's legal obligations and statutory goals to assess and disclose potentially significant incremental effects bearing on the public interest. The social cost of greenhouse gases methodology calculates how the emission of an additional unit of greenhouse gases affects atmospheric greenhouse concentrations, how that change in atmospheric concentrations changes temperature, and how that change in temperature incrementally contributes to the above list of economic damages, including property damages, energy demand effects, lost agricultural productivity, human mortality and morbidity, lost ecosystem services and non-market amenities, and so forth[citation provided in original comment]. The social cost of greenhouse gases tool therefore captures the factors that actually affect public welfare and assesses the degree of impact to each factor, in ways that just estimating the volume of emissions cannot.	As stated in the EA, Section 3.2.3.5, "The SCC protocol does not measure the actual incremental impacts of a project on the environment and does not include all the positive or negative effects of carbon emissions. The SCC protocol estimates economic damages associated with an increase in CO_2 emissions 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 BLM has acknowledged that climate science does not allow a precise connection between project-specific GHG emissions and specific environmental effects of climate change. This approach is consistent with the approach that federal courts have upheld when considering NEPA challenges to BLM federal coal leasing decisions. WildEarth Guardians v. Jewell, 738 F.3d 298, 309 n.5 (D.C. Cir. 2013); WildEarth Guardians v. BLM, , 8 F. Supp. 3d 17; 34 (D.D.C. 2014). The analysis provided by this leasing EA is consistent with existing BLM direction. Also, see responses to Comments #3 and #5.
5	Joint NGO Letter	Climate Change	Capturing how marginal climate damages change as the background concentration changes is especially important because NEPA requires assessing both potentially significant present and future impacts [citation provided in original comment]. Different project alternatives can have different greenhouse gas consequences over time. Most simply, different alternatives could have different start dates or other consequential changes in timing. Calculating volumes or percentages, especially on an average annual basis as BLM does here, is insufficient to accurately compare the climate damages of project alternatives with varying greenhouse gas emissions over time. By reporting only volumetric greenhouse gas projections, BLM paints an incomplete and misleading portrait of the relative climate impacts of the proposed action. This problem would be easily solved by applying the social cost of greenhouse gases metric, which seamlessly accounts for timing differences between different alternatives. By factoring in projections of the increasing global stock of greenhouse gases as well as increasing stresses to physical and economic systems, the social cost of greenhouse gas metrics enable accurate and transparent comparisons of projects with varying greenhouse gas emissions over time.	SCC estimates the monetary cost incurred by the emission of one additional metric ton of carbon dioxide (CO_2), and is not applicable to non-CO_2 GHG emissions, such as methane. Estimating SCC is challenging because it is intended to model effects on the welfare of future generations at a global scale caused by additional carbon emissions occurring in the present and does not account for the complexity of multiple stressors and indicators. The SCC was developed to support agencies in responding to EO 13514, not for use in making land management decisions. Also, see response to Comment #3.
6	Joint NGO Letter	Climate Change	NEPA requires sufficient informational context. Yet the limited context that BLM provides for the project's projected greenhouse gas emissions—namely, comparing such totals to largely irrelevant volumes of greenhouse gas emissions including the U.S. greenhouse gas inventory [citation provided in original comment]—provides a confusing and inadequate picture that attempts to minimize the impacts of the proposed action's substantial emissions. Indeed, in a country of over 300 million people and over 6.5 billion tons of annual greenhouse gas emissions, it is far too easy to make highly significant effects appear relatively trivial[citation provided in original comment]. Indeed, as the District of Montana recently explained, "[t]he global nature of climate change and greenhouse-gas emissions means that any single lease sale or BLM project likely will make up a negligible percent of state and nation-wide greenhouse gas emissions."—yet, as the court explained, that fact does not excuse agencies from their obligation to meaningfully assess their action's contributions to climate change[citation provided in original comment]. In other words, percentages can be misleading and can be manipulated by the choice of the denominator; what matters is the numerator's actual contribution to total harm… By presenting large quantities of emissions—more than 12 million metric tons—as a tiny percentage representing less than 0.2 percent of a much larger total, the EA is likely to cause stakeholders to misunderstand the true significance of these emissions and treat them as meaningless. By comparison, through monetization it becomes clear that, for example, annual gross emissions from the project could cause about $633 million in climate damages *in a single year* [citation provided in original comment].	BLM recognizes that GHG emissions contribute to increased concentrations of GHG in the atmosphere and, thus, contribute to global climate change. Information about climate change projections from global climate models that evaluate natural systems and feedback mechanisms contributing to climate variability globally is available in the IPCC's Fifth Assessment Report (AR5) (IPCC 2014), and the EA includes a basic synthesis of these results, briefly, stating: "The range of likely change in global surface temperature by 2050 ranges from 0.3 to 1 degree Celsius for the RCP2.6 scenario and from 0.5 to 2.0 degrees Celsius for the RCP8.5 scenario ... When discussing regional impacts, however, it is important to note that degrees of surface temperature increases vary from region to region." Because there are over 30 climate change models, and projected effects of global climate change vary from region to region, the general approach of the BLM and OSMRE has been to quantify the incremental increase in GHG emissions resulting from a project to determine the relative intensity of the project's potential impacts, then to discuss the potential effects of climate change in the region where the project occurs in lieu of attempting to summarize all potential scenarios and varying regional impacts of climate change globally. Also, see response to Comment #4.

Comment #	Commenter	Comment Topic	Comment	BLM Response
7	Joint NGO Letter	Climate Change	Additionally, abstract volume estimates fail to give people the required informational context due to another well-documented mental heuristic called “scope neglect.” Scope neglect, also explained by Kahneman and others, causes people to ignore the size of a problem when estimating the value of addressing the problem… By failing to contextualize greenhouse gas emissions in the EA, BLM potentially misleads the reader into believing that there would be no climate effects from the proposed action, or that the effects would be extremely limited. As a result of scope neglect, for instance, many decisionmakers and members of the public may be unable to meaningfully contextualize the significance of 0.2% of U.S. emissions. While decisionmakers and the public may be able to tell this is a non-zero number, without any context it may be difficult to weigh the climate risks to which this volumetric estimate equates. In contrast, the project’s climate risks would be readily discernible through application of the social cost of greenhouse gas metrics. While the impact of releasing an additional 12.17 million metric tons of carbon dioxide equivalent annually into the atmosphere may seem indiscernible, that impact is clearly conveyed by explaining that such a figure represents approximately $633 million per year in annual climate damages[citation provided in original comment].	Climate change and potential climate impacts, in and of themselves, are often not well understood by the general public (Etkin and Ho 2007; National Research Council 2009). This is in part due to the challenges associated with communicating about climate change and climate impacts, stemming in part from the fact that most causes are invisible factors (such as greenhouse gases) and there is a long lag time and geographic scale between causes and effects (National Research Council 2010). Research indicates that for difficult environmental issues such as climate change, most people more readily understand if the issue is brought to a scale that is relatable to their everyday life (Dietz 2013); when the science and technical aspects are presented in an engaging way, such as narratives about the potential implications of the climate impacts (Corner et al. 2015) and by using examples and making information relevant to the audience while also linking the local and global scales (National Research Council 2010). The approach taken by the BLM for this EA to discuss climate change provides impacts at several scales whereas the social cost of carbon metric only provides an impact metric at the global scale. This limits the usefulness for the decision-maker given the lack of information on more localized impacts. Also, see response to Comment #3.
8	Joint NGO Letter	Climate Change	Monetizing climate damages provides the informational context required by NEPA, whereas a simple tally of emissions volume and a qualitative, generic description of climate change are misleading and fail to give the public and decisionmakers the required information about the magnitude of discrete climate effects [citation provided in original comment]. Thus, while BLM treats “emissions as a proxy for the potential climate change impact from the Proposed Action” throughout the EA [citation provided in original comment], the social cost of greenhouse gases metrics in fact convey and contextualize the project’s potentially significant climate effects in ways that quantification alone cannot, and thus should be utilized to help satisfy the agency’s obligations under NEPA.	The BLM prepared this EA to fully satisfy its obligations under NEPA. Please see the response to Comment #3 for reasons the BLM did not monetize climate effects in this EA.
9	Joint NGO Letter	Climate Change	Though NEPA does not always require a full and formal cost-benefit analysis [citation provided in original comment], agencies’ approaches to assessing costs and benefits must be balanced and reasonable. Courts have warned agencies, for example, that an agency cannot selectively monetize benefits in support of its decision while refusing to monetize the costs of its action [citation provided in original comment]. … The EA monetizes economic benefits similar to those highlighted in High Country and MEIC, including government revenues such as taxes and royalties [citation provided in original comment]. BLM does not sufficiently justify this inconsistent approach to monetizing some potentially significant effects but not others, but tries to skirt the precedent set in the cases discussed above by labeling taxes and royalties as “economic impacts” rather than costs or benefits [citation provided in original comment]. First, as explained in MEIC v. OSM, this is a semantical “distinction without a difference.” [citation provided in original comment] Indeed, NEPA regulations group all impacts—including economic, social, ecological, and public health—under the same category of “effects,” and NEPA requires the agency to discuss all of these effects in as much detail as possible [citation provided in original comment]. Whether a potentially significant effect is a cost, benefit, or transfer, if monetization is the best way to assess it and contextualize its precise impacts, then monetization is also the best way to comply with NEPA’s obligations. Second, BLM uses the sale price for coal, which reflects market value of the resource, to calculate possible royalties from the proposed action [citation provided in original comment]. This explicitly uses the market price into the calculation of the action’s economic “effects.” [citation provided in original comment] In a competitive market, like for coal, oil, and gas, the market price is typically thought to reflect aggregate willingness to pay based on social utility. Therefore, in calculating and reporting royalties, BLM has effectively presented a monetized estimate of the proposed action’s projected social benefits. Furthermore, the annual economic output from mine is about $146.25 million [citation provided in original comment], which is far outweighed by the project’s climate costs of $633 million… Agencies are every bit as capable of monetizing climate damages as they are of monetizing socioeconomic impacts. BLM therefore violates NEPA by monetizing potentially significant social and economic effects in the EA while refusing to monetize climate impacts.	Taxes and revenues from coal production are described in the socioeconomics affected environment portion of the EA, which describes existing conditions. Because the proposed leasing action is a continuation of current conditions, it is reasonable to describe the continuation of taxes and revenues. The EA based this assessment on the stated assumption that the average price for coal would be similar to the 2017 average sales price. The EA also recognizes the potential for “boom and bust” cycles in natural resource economies. Also, see response to Comment #3.

Comment #	Commenter	Comment Topic	Comment	BLM Response
10	Joint NGO Letter	Monetizing emissions	BLM argues that it cannot monetize the proposed action's effects on greenhouse gas emissions because "the [social cost of greenhouse gases] protocol does not measure the actual incremental impacts of a project on the environment."[citation provided in original comment] BLM further argues that "the [social cost of greenhouse gases] dollar cost figure is generated in a range and provides little benefit in assisting the authorized officer's decision for project level analyses."[citation provided in original comment] This statements, however, is simply incorrect: the social cost of greenhouse gas protocol is exactly such a tool to monetize the incremental climate impacts of specific projects or plans, and to contextualize the magnitude of those impacts. NEPA requires BLM to use the best available science to support its NEPA analysis, and the social cost metrics remain the best estimates yet produced by the federal government for monetizing the impacts of greenhouse gas emissions and are "generally accepted in the scientific community."[citation provided in original comment]	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.
11	Joint NGO Letter	Social Cost Metrics	BLM argues that use of the IWG's social cost metrics is inappropriate for this EA because it "is not engaged in a rulemaking for which the [social cost of carbon] protocol was originally developed."[citation provided in original comment] But this argument misses the point: BLM fails to explain why those metrics should not be used in environmental reviews when they provide the best method to convey the potentially significant climate impacts of a project that would contribute substantially to greenhouse gas emissions. Indeed, there is nothing in the development of the social cost metrics that would limit applications to other contexts. The social cost of greenhouse gases measures the marginal cost of any additional unit of greenhouse gases emitted into the atmosphere. The government action that precipitated that unit of emissions—a regulation, the granting of a permit, a project approval, or a master development plan—is irrelevant to the marginal climate damages caused by its emissions. Whether emitted by a leaking pipeline or the extraction process, because of a regulation or an integrated planning decision, or in Alaska or Maine, the marginal climate damages per unit of emissions remain the same. Indeed, the social cost of greenhouse gases has been used by many federal and state agencies in environmental impact reviews [citation provided in original comment] and resource management decisions [citation provided in original comment].	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.
12	Joint NGO Letter	Social Cost of GHG	Some of the potentially significant incremental impacts on the environment that the social cost of greenhouse gas protocol captures—and which the EA fails to meaningfully analyze—include property lost or damaged; impacts to agriculture, forestry, and fisheries; impacts to human health; changes in fresh water availability; ecosystem service impacts; impacts to outdoor recreation and other non-market amenities; and some catastrophic impacts, including potentially rapid sea-level rise, damages at very high temperatures, or unknown events [citation provided in original comment]. A key advantage of using the social cost of greenhouse gas tool is that each physical impact—such as sea-level rise and increasing temperatures—need not be assessed in isolation. Instead, the social cost of greenhouse gases tool conveniently groups together a multitude of climate impacts and, consistent with NEPA regulations, [citation provided in original comment] enables agencies to assess whether all those impacts are cumulatively potentially significant and to then compare those impacts with other impacts or alternatives using a common metric.	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.
13	Joint NGO Letter	Significance of GHG emissions	While there may not be a bright-line test, the emissions BLM estimates for this project are potentially significant and warrant monetization. This is especially true since, once emissions have been quantified, the additional step of monetization through application of the IWG's cost estimates entails a simple arithmetic calculation [citation provided in original comment]. It is difficult to understand how NEPA's mandate that an agency take a "hard look" at the potentially significant environmental impacts of its actions in an environmental impact statement can be satisfied if BLM fails to take the simple step of analyzing the potentially significant impacts of the greenhouse gas emissions that it quantifies.	Please see Section 3.2.3.5 of the EA and the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.

Comment #	Commenter	Comment Topic	Comment	BLM Response
14	Joint NGO Letter	Social Cost of GHG	BLM further implies that use the social cost of greenhouse gases would be inappropriate because it has not monetized the project's benefits [citation provided in original comment]. This is mistaken for several reasons. First, as noted above, BLM has monetized the full benefits of the project as an input into its calculation of government royalties [citation provided in original comment]. BLM's repeated attempts to hide behind its failure to monetize the proposed action's benefits therefore fails… Monetizing the project's potentially significant climate effects could also provide a framework for making decisions when some effects but not others are monetized, through what is known as "break-even analysis."… Even if BLM is unable to fully monetize all costs and benefits, it should explain why the alleged benefits of this proposal, about $146 million per year [citation provided in original comment], are worth the roughly $633 million in annual climate costs. Moreover, even without using something as formal as a break-even analysis, it is clear that monetizing climate damages provides useful information whether or not every effect can be monetized in a full cost-benefit analysis. NEPA regulations acknowledge that when monetization of costs and benefits is "relevant to the choice among environmentally different alternatives," "that analysis" can be presented alongside "any analyses of unquantified environmental impacts, values, and amenities." [citation provided in original comment]	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.
15	Joint NGO Letter	Social Cost of GHG	In March 2017, President Trump disbanded the IWG and withdrew its technical support documents. [citation provided in original comment] Nevertheless, Executive Order 13,783 assumes that federal agencies will continue to "monetiz[e] the value of changes in greenhouse gas emissions" and instructs agencies to ensure such estimates are "consistent with the guidance contained in OMB Circular A-4." [citation provided in original comment] Consequently, while federal agencies no longer benefit from ongoing technical support from the IWG on using the social cost of greenhouse gases, by no means does the new Executive Order imply that agencies should not monetize potentially significant effects in their environmental impact statements… Similarly, the Executive Order's withdrawal of the Council on Environmental Quality's guidance on greenhouse gases [citation provided in original comment], does not—and legally cannot—remove agencies' statutory requirement to fully disclose the potentially significant environmental impacts of greenhouse gas emissions. As the Council on Environmental Quality explained in its withdrawal, the "guidance was not a regulation," and "[t]he withdrawal of the guidance does not change any law, regulation, or other legally binding requirement." [citation provided in original comment] In other words, when the guidance originally recommended the appropriate use of the social cost of greenhouse gases in environmental impact statements [citation provided in original comment], it was simply explaining that the social cost of greenhouse gases is consistent with longstanding NEPA regulations and case law, all of which are still in effect today.	While the BLM cannot know what Executive Order 13783 assumes, the order specifically applies to regulations in stating that, "when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates, agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4 of September 17, 2003 (Regulatory Analysis), Order 13783 (March 28, 2017)…" The coal leasing action is not a change in regulation. Also, see response to Comment #3.
16	Joint NGO Letter	Social Cost of GHG	Generally, uncertainty is not a reason to abandon the social cost of greenhouse gas methodologies; [citation provided in original comment] quite the contrary, uncertainty supports higher estimates of the social cost of greenhouse gases, because most uncertainties regarding climate change entail tipping points, catastrophic risks, and unknown unknowns about the damages of climate change… Moreover, even the best existing estimates of the social cost of greenhouse gases are likely underestimated because the models currently omit many significant categories of damages—such as depressed economic growth, pests, pathogens, erosion, air pollution, fire, dwindling energy supply, health costs, political conflict, and ocean acidification, as well as tipping points, catastrophic risks, and unknown unknowns—and because of other methodological choices [citation provided in original comment]. Consequently, uncertainty suggests an even higher social cost of greenhouse gases and so is not a reason to abandon the metric, which would misleadingly suggest that climate damages are worthless.	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.

Comment #	Commenter	Comment Topic	Comment	BLM Response
17	Joint NGO Letter	Global Perspective	BLM mentions the availability of new "interim" estimates of the social cost of greenhouse gases that make changes "to the consideration of domestic versus international impacts and the consideration of appropriate discount rates." [citation provided in original comment] Those two changes are inappropriate and violate the obligations under NEPA to assess environmental consequences. NEPA contains a provision on "International and National Coordination of Efforts" that broadly requires that "all agencies of the Federal Government shall . . . recognize the worldwide and long-range character of environmental problems." [citation provided in original comment] Using a global social cost of greenhouse gases to analyze and set policy fulfills these instructions. Furthermore, the Act requires agencies to, "where consistent with the foreign policy of the United States, lend appropriate support to initiatives, resolutions, and programs designed to maximize international cooperation in anticipating and preventing a decline in the quality of mankind's world environment." [citation provided in original comment] By continuing to use the global social cost of greenhouse gases to spur reciprocal foreign actions, federal agencies "lend appropriate support" to the NEPA's goal of "maximize[ing] international cooperation" to protect "mankind's world environment." Furthermore, not only is it consistent with Circular A-4 and best economic practices to estimate the global damages of U.S. greenhouse gas emissions in regulatory analyses and environmental impact statements, but no existing methodology for estimating a "domestic-only" value is reliable, complete, or consistent with Circular A-4) Since at least 2010, including some recent agency actions under the Trump administration, [citation provided in original comment] federal agencies based their regulatory decision and NEPA reviews on global estimates of the social cost of greenhouse gases. Though agencies sometimes also disclosed a "highly speculative" range that tried to capture exclusively U.S. climate costs, emphasis on a global value was recognized as more accurate given the science and economics of climate change, as more consistent with best economic practices, and as crucial to advancing U.S. strategic goals [citation provided in original comment]....Because greenhouse pollution does not stay within geographic borders but rather mixes in the atmosphere and affects climate worldwide, each ton emitted by the United States not only creates domestic harms, but also imposes large externalities on the rest of the world. Conversely, each ton of greenhouse gases abated in another country benefits the United States along with the rest of the world....it is appropriate under Circular A-4 for agencies to continue to rely on global estimates of the social cost of greenhouses to justify their regulatory decisions or their choice of alternatives under NEPA.	As stated in the EA Section 3.2.3.3, "...confidence in the accuracy of regional- and sub-regional-scale projections is lower than at the global scale. While climate models account for global emissions, they do not provide estimates for impacts from a single source in isolation of other sources." Under Section 1500.1 of the NEPA implementing regulations: "The purpose and function of NEPA is satisfied if Federal agencies have considered relevant environmental information, and the public has been informed regarding the decision-making process. NEPA does not mandate particular results or substantive outcomes. NEPA's purpose is not to generate paperwork or litigation, but to provide for informed decision making and foster excellent action." The BLM has fully satisfied its obligations under NEPA. Although NEPA itself does not contain a provision on international and national coordination of efforts, the U.S. Code chapter 55 on National Environmental Policy states that all federal agencies shall "recognize the worldwide and long-range character of environmental problems and, where consistent with the foreign policy of the United States, lend appropriate support to initiatives, resolutions, and programs designed to maximize international cooperation in anticipating and preventing a decline in the quality of mankind's world environment..." Also see response to Comment #3.

Comment #	Commenter	Comment Topic	Comment	BLM Response
18	Joint NGO Letter		The EA complains that the "range" of estimates for the social cost of greenhouse gases—which is largely a function of using different assumptions about the discount rate—makes the metric not useful [citation provided in original comment]. Not only was this line of thinking rejected by the Ninth Circuit in Center for Biological Diversity—"while . . . there is a range of values, the value of carbon emissions reduction is certainly not zero" [citation provided in original comment]—but the range of values recommended by the Interagency Working Group [citation provided in original comment] and endorsed by the National Academies of Sciences [citation provided in original comment] is rather manageable. In 2016, the IWG recommended values at discount rates from 2.5% to 5%, calculated as between $12 and $62 for year 2020 emissions [citation provided in original comment]. Numerous federal agencies have had no difficulty either applying this range in their environmental impact statements or else focusing on the central estimate at a 3% discount rate [citation provided in original comment]....NEPA requires agencies to weigh the "relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity," as well as "any irreversible and irretrievable commitments of resources." [citation provided in original comment] That requirement is prefaced with a congressional declaration of policy that explicitly references the needs of future generations: The Congress, recognizing the profound impact of man's activity on the interrelations of all components of the natural environment . . . declares that it is the continuing policy of the Federal Government . . . to use all practicable means and measures . . . to create and maintain conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of Americans [citation provided in original comment]. The National Academies of Sciences' report also strongly endorses a declining discount rate approach due to uncertainty [citation provided in original comment]. In other words, the rational response to a concern about uncertainty over the discount rate is not to abandon the social cost of greenhouse gas methodology, but to apply declining discount rates and to treat the estimates calculated at a constant 3% rate as conservative lower-bound estimates. ...a 3% or lower discount rate for climate change implies the need for a 300-year horizon to capture all significant values. NAS reviewed the best available, peer-reviewed scientific literature and concluded that the effects of greenhouse gas emissions over a 300-year period are sufficiently well established and reliable as to merit consideration in estimates of the social cost of greenhouse gases [citation provided in original comment].	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA. A stated in the EA, Section 3.2.3.5, "As applied to the proposed lease modification areas, given the uncertainties associated with assigning an accurate SCC resulting from 3 additional years of operation under the Proposed Action, and given that the SCC protocol and similar models were developed to estimate impacts of regulations over long time frames, this EA quantifies direct and indirect GHG emissions and evaluates these emissions in the context of county, state, and U.S. GHG emissions as discussed in Section 3.2.3.3 of this EA."

Comment #	Commenter	Comment Topic	Comment	BLM Response
19	Southern Utah Wilderness Alliance – Center for Biological Diversity – Sierra Club – WildEarth Guardians (SUWA et al.) Letter	Air quality -methane emissions	The EA arbitrarily uses only the 100 year global warming potential (GWP) for methane instead of also considering the 20-year GWP. BLM also underestimates the methane emissions from the mine ventilation exhaust by having relied on outdated data… BLM failed to consider best management practices and EPA white paper guidance regarding methane emission reductions.	The EPA uses the 100-year time horizon in its Inventory of Greenhouse Gas Emissions and Sinks: 1990-2018 (EPA 2020) and Mandatory Greenhouse Gas Reporting rule. Therefore, project-related emissions are shown based on the 100-year GWP values for comparison to state, national, and global GHG emissions. The GWPs used to calculate CO_2e emissions are based on the IPCC's Climate Change 2014: Synthesis Report for the 100-year timescale (IPCC 2014). The 20-year GWP is sometimes used as an alternative to the 100-year GWP. The 20-year GWP prioritizes gases with shorter lifetimes because it does not consider impacts that happen more than 20 years after the emissions occur. Based on the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC), CH_4 has a lifetime of 12.4 years and a global warming potential of 28 over 100 years. However, for the Lila Canyon EA, the 20-year GWP would not be substantially different from the 100-year GWP because 1) the Lila Canyon Mine is a negligible source of methane; 2) methane in the coal will be converted to CO_2 during the combustion process and the GWP for CO_2 is the same for the both 100 and 20-year GWP; and 3) reporting the 20-year GWP does not change the climate change impacts that were already discussed in Section 3.2.3.6. Methane emissions from the ventilation system were estimated as per 40 CFR Part 98 (MRR of GHG from Underground Coal Mines), Equation FF-1. The flowrate, dry bulb temperature, and barometric pressure (i.e., 88,085 CFM, 52.21 °F and 24.32 in) were based on sample measurements taken quarterly during calendar year 2011 and used as basis for the Lila Canyon Mine NOI dated May 10, 2013. Furthermore, since the ventilation data is based on historic sample measurements, a conservative factor of 2 was applied to the methane emission calculations to account for a potential increase in the methane concentration or ventilation flow rate. A bottle sample taken by MSHA for first quarter fiscal year 2021 showed that the Mine liberated 466,421 cubic feet of methane in 24 hours with airflow of 815,000 cubic feet of air per minute. This calculates to approximately 0.04% methane in the exiting air (BLM 2020c). Differences in air density and number of days the ventilation fans operate may change the total estimate.
20	SUWA et al. Letter	Air quality – indirect emissions	BLM miscalculated the emissions from power plants that will burn the coal removed from the Lila Canyon Mine. And BLM relied on data for sub-bituminous coal but the coal at issue is bituminous, which has higher NOx emissions.	BLM updated the emissions calculations shown in Table 3-10 and Table 3-11 and text in Section 3.2.3.2 of the EA to account for bituminous coal combustion. To estimate the emissions from the combustion of the mined bituminous coal, criteria and hazardous air pollutant (HAP) emission factors from U.S. EPA AP-42 for bituminous and subbituminous coal combustion were obtained. Emission factors for pulverized coal, dry bottom, tangentially fired, bituminous, pre-NSPS firing configuration were used to estimate worst-case combustion emissions from the combustion of the mined coal. NO_x emissions increased in Table 3-10; annual GHG emissions decreased for CO_2 and CO_2e in Table 3-11.
21	SUWA et al. Letter	Air quality – cumulative impacts	BLM ignored numerous other projects in this region that will have cumulative air quality and climate impacts.	The EA has been updated to list past and present actions including coal mining, mineral mining, and oil and gas activity, which contribute to current air quality conditions in the region (Table C-1, Appendix C). This includes an estimate of GHG emissions from oil and gas wells in the BLM PFO and Utah, as well as regional and national emissions, which have been added to Section 3.2.3.6. In addition, a list (Table C-2, Appendix C) of reasonably foreseeable future actions currently known to the BLM PFO, which may contribute to future emissions and climate impacts during the 2- to 3-year extension of the mining activities, has been added to the EA.
22	SUWA et al. Letter	Cumulative impacts	The EA states that the "past and present actions that would affect the resources analyzed in this EA are underground mining operations."2 With regard to reasonably foreseeable future actions the EA identifies other mining projects "in the vicinity" of the lease modification areas."3 This includes a coal lease on SITLA lands, an LBA for Williams Draw, and a coal lease in Walker Flat. 4 These are not the only projects that have had or will have impacts on resources in this region including air quality, climate, water resources, and socioeconomic, among others.… Specifically, the agency failed to identify and analyze past, present, and reasonably foreseeable future actions.	A list of past and present actions has been added to Appendix C (Table C-1) of the EA. Past and present actions are part of the current baseline condition in the vicinity of the Lila Canyon Mine. The list of reasonably foreseeable future actions has been added to Appendix C (Table C-2) of the EA. The BLM has recently completed a report summarizing cumulative greenhouse gas emissions for Utah and the BLM Price Field Office (Utah Bureau of Land Management Air Resource Management Strategy 2020 Monitoring Report). This report is referenced in the EA, Section 3.1, and will be available on BLM's ePlanning site. Statements have been added to the EA Proposed Action cumulative effects sections to address the additional reasonably foreseeable future actions listed in Appendix C. Also, see response to Comment #21.

Comment #	Commenter	Comment Topic	Comment	BLM Response
23	SUWA et al. Letter	Cumulative impacts	Before BLM can identify past, present, and reasonably foreseeable future actions, it must first establish its "cumulative impacts analysis area," or CIAA. …BLM never defined the CIAA for air quality or climate.	The cumulative effects analysis area for air quality and greenhouse gas emissions is identified in Section 3.2 of the EA and includes the near-field criteria pollutant assessment of 50 km. The air quality modeling domain includes Emery and Carbon Counties. The BLM also looked at the nearby Class I areas at the extent of the domain. For GHG, BLM looked at a global impact area (national and global scale emissions and modeling).
24	SUWA et al. Letter	Past, Present, and Reasonably Foreseeable Future Actions	BLM identified only four past, present, or reasonably foreseeable actions [citation provided in original comment]. These are not the only projects that have or will impact the resources considered in the EA, including air quality and climate…. BLM has approved similar coal lease modifications for, at least, five other projects in Utah…. BLM has issued hundreds of oil and gas leases for development in Utah including in and near Carbon County… BLM has approved development projects that will impact air quality and climate, among other resources… And there are other ongoing large-scale proposals that will impact these same resources. …The EA does not identify these projects, even though each project will impact air quality, climate, water, and socioeconomic resources, among others	See responses to Comments #21 and #22. The coal lease modification projects mentioned in the comment have decision dates between 2009 and 2018, and for the air quality discussion, their emissions would be part of the affected environment. Oil and gas development is discussed in Section 3.5 of the EA; additional information has been added to the cumulative effects analysis (EA Section 3.2.3.6 and Appendix C).
25	SUWA et al. Letter	Cumulative impacts	In addition to identifying past, present, and reasonably foreseeable actions that might affect the environment in the project area, BLM must analyze the cumulative impacts of those actions in combination…. these projects and their cumulative impacts must be considered in the EA. This includes whether the proposed action—when viewed together with these other projects—may violate any NAAQS, or consideration of the total climate impact of these projects. It also includes the cumulative impacts to socioeconomics, water resources, and other resource impacts such as wildlife species.	See response to Comment #21. If the resource analysis for a specific resource shows no direct or indirect impacts, then no cumulative impact analysis is needed for that resource. Predictions of violations of the NAAQS are not the purview of BLM's NEPA EA. The Utah Division of Air Quality is responsible for commercial and industrial air quality permitting, compliance, and enforcement. The EA does not evaluate violations, but rather the potential for exceedances. For the NAAQS, a violation has a specific meaning, primarily being that the three-year average of the standard exceeded the NAAQS. The EA does not look at three-year averages but rather the potential to exceed during a given year.
26	SUWA et al. Letter	Social Cost of Carbon	The social cost of carbon provides an estimate of the economic damage, in dollars, caused by each incremental ton of carbon dioxide emitted into the atmosphere, including impacts such as increased drought, wildfires, decreased agricultural productivity, and sea level rise, among others [citation provided in original comment]. By translating climate impacts, and tons of greenhouse gasses in particular, into dollars, the social cost of carbon offers BLM an easy to use and easy to understand tool that would allow the public and decisionmakers to better understand the climate impacts of BLM's decision here. …The social cost of greenhouse gases remain valid and generally-accepted scientific tools that BLM should have used pursuant to 40 C.F.R. §§ 1500.1(b) and 1502.22 to monetize the impact of GHG emissions in its estimation of the Mine's economic impacts [citation provided in original comment].	Please see the response to Comment #3 for reasons why the BLM did not monetize climate effects in this EA.

Comment #	Commenter	Comment Topic	Comment	BLM Response
27	SUWA et al. Letter	Global carbon budget	BLM must acknowledge and address the extent to which the proposed action conflicts with our national emissions reduction goals and international climate commitments, including internationally-agreed upon carbon budgets…. the 2018 IPCC Special Report provides overwhelming scientific evidence for the necessity of immediate, deep greenhouse gas reductions across all sectors to avoid devastating climate change-driven damages, and underscores the high costs of inaction or delays, particularly in the next crucial decade, in making these cuts…. BLM must address the recent studies and reports on the concept of global carbon budgeting, which was not addressed by BLM in this NEPA review or in the Lifting the Pause on the Issuance of New Federal Coal Leases for Thermal (Steam) Coal EA (a carbon budget alternative was proposed but rejected by the agency [citation provided in original comment]). Furthermore, BLM must evaluate how the direct and indirect greenhouse gas emissions associated with the proposed Lila Canyon Mine lease modifications affect the remaining available carbon budget.	Analysis of the Proposed Action within the context of the U.S. production gap or emission gap between current fossil fuel production and climate goals is outside of the scope of the Proposed Action because the BLM leases represent a subnational portion of fossil fuel production and GHG emissions, which is in effect, driven by regional supply and demand. Large-scale changes in energy use trends are generally driven by federal or state-level regulations such as renewable portfolio standards or other relevant requirements that are designed to increase renewable energy supply. The BLM's rejection of mining of federal coal would have little to no impact on the overall coal supplied as applicants would be likely to simply mine other coal tracts to provide coal in a less-efficient manner than the logical mining sequence if the federal coal lease is approved. Additionally, presenting the emissions data in comparison with the production or emission gap information does not provide the decision-maker and the public any more context of the significance of impacts when compared to disclosing the relative magnitude of GHG emissions at multiple geographic scales as a proxy for climate change impacts. Use of the latter methodology is more consistent with the draft 2019 NEPA guidance on consideration of GHG emissions and is the most consistent methodology by which impacts are presented and evaluated across BLM field offices. GHG emissions for the Proposed Action have been quantified and have provided various contextual comparisons (including geographic comparisons at the regional, state, national, and global levels). Carbon budgeting is a simplified approach for identifying how much additional CO_2 emissions the atmosphere can accept in order to limit global warming to a certain temperature above pre-industrial levels (2.0°C for Paris Agreement, 1.5°C for IPCC 2018 Special Report). The carbon budget was developed as a tool to assist policy makers in reducing GHG emissions on national and global scales. There is no requirement or mechanism to apply a worldwide carbon budget to a site-specific project such as the Proposed Action. Carbon budgets do not currently exist at the national or state level, and creating such a budget is beyond the scope of this EA. While a carbon budget sounds like a simple tool, there is a lot of complexity and uncertainty to it that make it confusing to the decision-maker and public. There are multiple carbon budgets to choose from, each representing a different amount of global warming. Even for a carbon budget that limits warming to 1.5°C, scientists have struggled to agree on the size of the budget. According to the Intergovernmental Panel on Climate Change (IPCC) 2018 Special Report (SR), "uncertainties in the size of these estimated remaining carbon budgets are substantial." The IPCC SR estimates the budget for a 50/50 chance of exceeding 1.5°C at 580 gigatonnes of CO_2 ($GtCO_2$), with an uncertainty of ±400$GtCO_2$. This uncertainty is nearly 70% of the budget. The uncertainty results from what the precise meaning of the 1.5°C target is, definition of what "surface temperature" means, definition of the "pre-industrial" period, what observational temperature dataset to use, uncertainty in non-CO_2 factors that influence warming, and if earth-system feedbacks should be taken into account. With the large uncertainty in the remaining carbon budgets, it is not a useful tool for evaluating a GHG emissions significance level at this time. Additionally, carbon budgets are inherently reduced with any GHG emissions. Based on the disclosed GHG emissions in the EA and the substantial uncertainties in the size of carbon budgets, inclusion of carbon budgets would not provide additional useful information to the decision-maker or the public. The IPCC SR further states that policy actions across sectors and spatial scales are needed to reduce emissions and limit warming. Evaluations of such policy actions are beyond the scope of this EA.

Comment #	Commenter	Comment Topic	Comment	BLM Response
28	SUWA et al. Letter	Methane global warming potential	BLM's failure to calculate CO2e for methane based on the 20-year GWP is an important omission because methane has greater radiative forcing (i.e., a greater capacity to warm the atmosphere), but a shorter atmospheric lifetime, than CO2, and is therefore a more potent greenhouse gas in the near-term. In the EA, BLM utilized only a single methane GWP of 28, reporting annual methane emissions (direct, indirect, and indirect from coal combustion) [citation provided in original comment] of 2,927 tons per year [citation provided in original comment]. Although BLM does not specify the combined CO2e for methane, using BLM's outdated 100-year GWP of 28 yields disclosed methane emissions of 81,956 tons CO2e per year (2927 x 28). Even using the range of EPA values for methane GWP for both 100-year and 20-year GWP, however, yields far greater CO2e: 81,956 – 105,372 annual tons CO2e using the 100-year GWPs; 245,868 – 254,649 annual tons CO2e using the 20-year GWPs [citation provided in original comment]. Instead BLM only applied an outdated 100-year GWP of 28. Application of the 20-year GWPs yields at least three times the amount of CO2e for methane emissions than BLM disclosed in the EA, even using the low-end estimate of 84 for the 20-year GWP. Thus, BLM must disclose the most current IPCC-20- and 100-year GWPs for fossil methane.	The EPA uses the 100-year time horizon in its Inventory of Greenhouse Gas Emissions and Sinks: 1990-2018 (EPA 2020h) and Mandatory Greenhouse Gas Reporting rule. Therefore, project-related emissions are shown based on the 100-year GWP values for comparison to state, national, and global GHG emissions. The GWPs used to calculate CO_2e emissions are based on the IPCC's Climate Change 2014: Synthesis Report for the 100-year timescale, which are the most recent GWPs available (IPCC 2014). However, for the Lila Canyon EA, the 20-year GWP would not be substantially different from the 100-year GWP because 1) the Lila Canyon Mine is a negligible source of methane; 2) methane in the coal will be converted to CO_2 during the combustion process and the GWP for CO_2 is the same for the both 100 and 20-year GWP; and 3) reporting the 20-year GWP does not change the climate change impacts that were already discussed in Section 3.2.3.6.
29	SUWA et al. Letter	Wildlife	…there has not been any meaningful consideration of potential indirect and cumulative impacts to plants and animals or their habitat stemming from the proposed lease modifications…any potential indirect and cumulative impacts, including but not limited to those discussed above, to the federally listed Mexican spotted owl, humpback chub, razorback sucker, bonytail, and Colorado pikeminnow must be considered. ..BLM has the same duty to consider potential impacts to the Horse Canyon stickleaf, a BLM-sensitive species	As stated in Appendix A of the EA, no surface disturbance is proposed, and no surface expression of subsidence is anticipated from the two proposed lease modifications. Due to the existing monitoring and response plan and the anticipated lack of surface disturbance, no impacts to sensitive wildlife populations or their habitat are expected. Analysis of soils, geology, elevation, and ecological systems overlying the proposed lease modification areas indicates the potential for suitable habitat for *Mentzelia multicaulis* var *librina* (Horse Canyon stickleaf). There are possible exposures of suitable geology, Price River Formations, and it is close to the typical elevation. Although suitable habitat for this plant occurs, there would be no impacts to habitat because no surface disturbance is proposed or anticipated. Due to the depth of the coal resource and therefore the coal mining activity in the lease modification areas, and the lack of surface disturbance, no impacts to fish populations or their habitat from the proposed underground mining operations are expected, as explained in the ID Team checklist (see EA Appendix A). The ID Team Checklist (Appendix A) has been updated to identify the potential for impacts to federally listed fish. Applicable analysis has been added to the EA. Appendix E has also been added to address the potential for indirect impacts on federally listed fish from mercury and selenium deposition from coal combustion at local power plants.
30	SUWA et al. Letter	Wildlife	BLM here failed to conduct, collect, or examine adequate current baseline studies for wildlife species and their habitat,	See response to Comment #29.
31	SUWA et al. Letter	ESA	…it is not evident that BLM requested from FWS whether any listed or species proposed for listing under the ESA are present in the proposed action area…. there has not been any ESA compliant consultation and analysis of all consequences to listed (or potentially listed) species and their habitat stemming from the proposed lease modifications.	The IDT checklist (EA Appendix A) references the U.S. Fish and Wildlife Service Information, Planning and Consultation (IPaC) system coordination. The IDT checklist has been updated to add additional detail. The BLM fulfilled its obligations under the ESA. The BLM determined that there may be potential indirect impacts to federally listed fish. Applicable analysis has been added to the EA. Appendix E has also been added to address the potential for indirect impacts on federally listed fish from mercury and selenium deposition. Informal consultation with the U.S. Fish and Wildlife Service concluded in concurrence with BLM's 'may affect but not likely to adversely affect' determination for indirect effects to Colorado River endangered fish and their critical habitats (Appendix E).
32	SUWA et al. Letter	ESA - MSO	While the EA acknowledges that "Mexican spotted owl (Strix occidentalis lucida) [MSO]– Designated critical [sic] occurs within the proposed lease modification areas," [citation provided in original comment] it provides no further information about the species, its habitat, or its status within and adjacent to the proposed lease modification areas…. BLM and FWS appear to have never meaningfully analyzed the potential effects of the Lila Canyon Mine and these proposed leased modifications on the species and/or its critical habitat.	The IDT checklist (EA Appendix A) has been updated to provide additional analysis of MSO and its critical habitat. Also, see Appendix E, correspondence from the U.S. Fish and Wildlife Service.

Comment #	Commenter	Comment Topic	Comment	BLM Response
33	SUWA et al. Letter	ESA - fish	…using the county in which the Lila Canyon Mine falls as the analysis area is arbitrary and ignores regional effects to federally listed species and their habitat that would stem from the proposed lease modifications, such as mercury and selenium deposition from coal combustion. Furthermore, the EA categorically dismisses that there may be any impacts to fish from the lease modifications [citation provided in original comment]. Such a cursory dismissal falls far short of ESA-compliant analysis…. That mercury emissions from the Hunter and Huntington power plants may affect the Colorado pikeminnow, razorback sucker, humpback chub, and bonytail is illustrated by a series of maps prepared by WildEarth Guardians using the Environmental Protection Agency's Regional Modeling System for Aerosols and Deposition protocol, or REMSAD, and relying on the agency's methods [citation provided in original comment]. Based on this model, Guardians modeled that the Hunter power plant contributes 5.37% of total mercury deposition in the Green River Basin, with Huntington contributing 19.52%. More detailed modeling of the individual power plants also shows that both power plants' mercury deposition footprints are more heavily concentrated in the Green River watershed, particularly in the Huntington Creek and Price River drainages [citation provided in original comment]. By failing to consult with the FWS about potential effects to the endangered Colorado pikeminnow, razorback sucker, humpback chub, and bonytail and their critical habitat, the agency has violated Section 7 of the ESA.	See response to Comment #31. There would be no impacts to fish species or their habitat from the proposed underground mining operations because of the depth of the coal and because neither fish nor perennial surface waters exist in the lease modifications areas. The ID Team Checklist (Appendix A) has been updated to identify the potential for impacts to federally listed fish. Applicable analysis has been added to the EA. Appendix E has also been added to address potential indirect impacts on federally listed fish from mercury and selenium deposition. Please see Appendix A of the EA and Section 3.4 of the EA for the surface water resources analysis. Emissions from the Hunter and Huntington power plants are regulated under State of Utah permits. The EA acknowledges that it is likely that some of the coal mined from the lease modification areas would be combusted at the Hunter or Huntington power plants. The proposed lease modifications and operation of Hunter and Huntington power plants are not interrelated nor interdependent. Specifically, even though the most logical use for the coal is the local market, the leasing does not depend upon operation of the power plants (there are other markets for the coal), nor does operation of the power plants depend upon issuance of the lease modification (there are other sources of coal available for purchase). The EA has been updated with a review of potential indirect impacts to the Colorado River endangered fish. BLM has consulted informally with the U.S. Fish and Wildlife Service (See Appendix A and Appendix E).
34	SUWA et al. Letter	Best available science	BLM presented little to no evidence that the proposed action will not affect threatened and endangered species like the Mexican spotted owl and Colorado River endangered fishes, and their critical habitats, the agency has not complied with the ESA's mandate to apply the best available science. BLM must clearly demonstrate that its decision is based on analysis of the best available science as the ESA requires.	See response to Comments #31 and #33.
35	SUWA et al. Letter	Outdated information and data	The BLM must update its data and analysis in the EA to incorporate the 2019 Lila Canyon Mine Annual Report (2019 Report) [citation provided in original comment] and cannot continue to rely on the outdated 2018 Lila Canyon Mine Annual Report (2018 Report) [citation provided in original comment]. NEPA requires BLM to rely on accurate, up-to-date, scientific information and data [citation provided in original comment]…. The 2019 Report was provided to the Utah Division of Oil, Gas and Mining on March 11, 2020—nearly two months before BLM released the draft EA [citation provided in original comment]. BLM fails to meet NEPA's informed decision-making mandate when it relies on unrepresentative information and data [citation provided in original comment].	The EA was completed based upon the use of reliable existing data and resources. The BLM reviewed and considered the 2019 report data.
36	SUWA et al. Letter	Range of alternatives	SUWA recommends the following alternatives, each of which will accomplish BLM's stated objectives, are technically and economically feasible, and will reduce impacts to the environment: • A "moderate expansion" alternative. Under this alternative, BLM would expand UEI's existing lease to include UTU-014218, adding approximately 317 acres to the Lila Canyon mine. BLM would not lease UTU-0126947. This alternative would differ from the proposed action alternative in several ways, including the amount of recoverable coal, scope of coal mining activities, and environmental impacts. Notably, this alternative would reduce GHG emissions. • A "methane emissions reduction" alternative. Under this alternative, BLM would lease both UTU-014218 and UTU-0126947 and also require implementation of the best management practices and methane emissions reduction strategies discussed in Ms. Williams' air quality report [citation provided in original comment]. This alternative differs from the proposed action alternative in that it would reduce the GHG emissions and climate impacts of the proposed action alternative.	Under the 43 CFR 3400 rules, the BLM is responsible for responding to a lease modification application by ensuring, among other things, the recoverability of the coal resource and that the plans to mine and extract coal do not jeopardize other coal resources or cause the bypass of valuable federal coal reserves. Coal tracts must be logically delineated and maximum economic recovery of the coal resource is required based upon current mining technology. For these reasons, the "moderate expansion" alternative would not be considered for this EA. Methane has been measured as undetectable at the Lila Canyon Mine vents and thus a methane reduction alternative was not considered. The NEPA directs the BLM to "study, develop, and describe appropriate alternatives to recommended courses of action in any proposal that involves unresolved conflicts concerning alternative uses of available resources…" No such unresolved conflicts of available resources are present in this case, and no other action alternatives are justifiable.
37	SUWA et al. Letter	Information documentation	The EA does not comply with 40 C.F.R. § 1506.5 because BLM has not independently evaluated the accuracy of documentation cited therein, nor does BLM even know where to find the documentation…. In its request to BLM, SUWA asked for the documentation verifying that BLM has independently evaluated and verified the accuracy of Lila Canyon Mine's information regarding the methane and VOC concentrations in the ventilation exhaust. Despite multiple requests from SUWA to BLM, the agency never released the documentation indicating that BLM had independently evaluated the information provided by Lila Canyon Mine. In fact, BLM could not even locate Lila Canyon Mine's methane and VOC concentration information by the end of the public comment period.	BLM verified independent sources for the methane and VOC data and evaluated the full extent of analyses in the EA. The EA is in compliance with 40 CFR 1506.5, which states: "The agency shall independently evaluate the information submitted or the environmental document and shall be responsible for its accuracy, scope, and contents." The BLM made the requested information available on ePlanning on May 8, 2020; the BLM extended the public comment period 2 weeks to allow for review of the supporting information.

Comment #	Commenter	Comment Topic	Comment	BLM Response
38	SUWA et al. Letter	Soils	…BLM failed to explain the composition of soils in the project area and never explained how subsidence and erosion would or would not impact the soils.	The conclusion is made in the EA and ID Team Checklist (Appendix A) that based on the depth of the coal seam from 2,000 to 3,000 feet, surface expression of subsidence should not be evident or measurable in the lease modification areas. Because of this, there would be no impacts to soils and thus soils are not described in detail in the EA. Subsidence is described in Section 2.4.2.3 of the EA. The surface water analysis is in Section 3.4 of the EA. The natural forces of erosion due to weathering and precipitation occur regardless of underground mining; see Section 3.4.3.1 of the EA for a statement on the role of natural erosion as related to subsidence.
39	SUWA et al. Letter	Vegetation	… with impacts to vegetation, the EA merely concludes in the ID Team Checklist that "[t]here is no new surface disturbance proposed or anticipated. Therefore, detailed analysis is not required." …Instead, BLM must analyze the connection between groundwater and vegetation, subsidence, and any pollution from the Proposed Action that could impact vegetation in the project area.	The ID Team Checklist (Appendix A) has been updated to clarify that based on the depth of the coal seam from 2,000 to 3,000 feet, no surface expression of subsidence is anticipated. A color infrared aerial photography study is also conducted as part of DOGM monitoring commitments under the Lila Canyon Mine permit approval. The study monitors impacts of subsidence on surface vegetation communities. The baseline data was gathered in 2011, and the study was repeated in 2016 per the 5-year interval requirement. No differences were observed between 2011 and 2016, suggesting that if subsidence occurred, it has had little impact to the plant and soil communities at the Lila Canyon Mine. The BLM considered soils, geology, elevation, and ecological systems within the proposed lease modification areas to determine surface resources requiring detailed analysis. As noted, vegetation is not a resource requiring detailed analysis in this EA.
40	SUWA et al. Letter	Visual resources	BLM has not analyzed the visual impacts from the "64-mile round trip along designated truck routes from the SCT to a regional coal-fired power plant, with an average capacity of 46 tons of coal per truck and a maximum of 11.2 trucks per hour (4.5 million tons of coal per year)." [citation provided in original comment] The Proposed Action takes place in an area classified as visual resource management (VRM) I.	As described in the IDT checklist in Appendix A of the EA, "Since no surface disturbance is proposed or anticipated, there will be no impact to visual resources and the existing character of the landscape will be maintained. Detailed analysis of visual resources is not required." The existing above ground facilities are within VRM classes 2 and 3. Approximately 0.3 mile of the county-maintained Lila Canyon Road is within VRM class 2, and the remaining 4.9 miles are within VRM class 3. Daily traffic along the Lila Canyon Road to U.S. Highway 6 is not anticipated to increase because the lease modification does not increase the amount of material that the permit holder can remove. Impacts to visuals would not change from previous NEPA analyses. The development of the Lila Canyon Mine surface facilities was analyzed in the BLM's Lila Canyon Project EA (BLM 2000) and referenced in the Lila Canyon Mine Lease Modifications EA (Section 2.4.2.1 and Section 3.1).

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APPENDIX G

List of Preparers

LIST OF PREPARERS

List of BLM and Non-BLM Preparers and Reviewers

Name	Title	EA Document Responsibility
BLM Preparers and Reviewers		
Michael Glasson	Geologist, Solid Minerals Lead, PFO	Project management, document review, geology/minerals/ energy production
Rebecca Anderson	Geologist, PFO	Document review and geology
Chris Conrad	Field Office Manager, PFO	Document review
Joseph Rodarme	NEPA Specialist, PFO	NEPA compliance, document review
Stephanie Howard	NEPA Lead, Vernal FO	Socioeconomics, NEPA compliance, document review
Erik Vernon	Air Quality Specialist, BLM State Office	Air quality and greenhouse gas emissions
Jared Dalebout	Hydrologist, BLM State Office	Ground water and surface water
Dana Truman	Assistant Field Manager, Resources, PFO	Special status species and ESA compliance
Jerrad Goodell	Aquatic Ecologist, Vernal FO	Surface water and fish habitat
Non-BLM Preparers and Reviewers		
Office of Surface Mining Reclamation and Enforcement		
Gretchen Pinkham	Natural Resources Specialist	Document review
SWCA Environmental Consultants		
David Steed	Director - Mining	Project management and QA/QC
Jeremy Eyre	Planner/NEPA Specialist	Chapters 1-2 and Socioeconomics
Linda Gottschalk	Permitting/NEPA Specialist	Project management and document review
Andrew Harley, PhD	Senior Mining Lead	Water resources review
KayLee Lavery	Natural Resources Planner	Administrative record
Kerri Linehan	Technical Editor	Technical editing
Gretchen Semerad	Environmental Scientist	Air quality and greenhouse gas emissions
Debbi Smith	Desktop Publishing and Production Coordinator	Formatting and Section 508
Brad Sohm, P.E.	Senior Air Quality Specialist	Air quality review
Calah Worthen	Water Resources Specialist	Water resources

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APPENDIX H

References

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