United States
Department of
Agriculture

Forest Service

Colorado
National Forests

October 2016

Rulemaking for Colorado Roadless Areas

Regulatory Impact Analysis

Colorado National Forests with roadless areas include:
Arapaho and Roosevelt; Grand Mesa, Uncompahgre, and Gunnison; Manti-La Sal (portion in Colorado); Pike and San Isabel; Rio Grande; Routt; San Juan; and White River National Forests

Commonly Used Acronyms

2012 FEIS – 2012 Rulemaking for Colorado Roadless Areas Final Environmental Impact Statement
BLM – Bureau of Land Management
BTU – British thermal unit
CARA – Comment Analysis and Response Application
CH_4 – Methane
CO_2 – Carbon dioxide
CO_2e – Carbon dioxide equivalent
CRA – Colorado Roadless Area
DEIS – Draft Environmental Impact Statement
EIS – Environmental Impact Statement
EPA – Environmental Protection Agency
ESA – Endangered Species Act
FEIS – Final Environmental Impact Statement
GHG – Greenhouse gas
GMUG – Grand Mesa, Uncompahgre, and Gunnison National Forests
GWh – Gigawatt hour
IMPLAN – IMpact Analysis for PLANning
IPM – Integrated Planning Model
IWG – Interagency Working Group
LAA – May affect, likely to adversely affect
LCZ – Linear construction zone
MAII – May adversely impact individuals, but not likely to result in a loss of viability, nor cause a trend toward federal listing
MDW – Methane drainage wells
N_2O – Nitrous oxide
NEPA – National Environmental Policy Act
NFS – National Forest System
NI – No Impact
NO_X – Generic term for the mono-nitrogen oxides NO and NO_2 gases
PNV – Present Net Value
OSMRE – Office of Surface Mining Reclamation and Enforcement
SCC – Social Cost of Carbon
SCM – Social Cost of Methane
SDEIS – Supplemental Draft Environmental Impact Statement
SEIS – Supplemental Environmental Impact Statement
SFEIS – Supplemental Final Environmental Impact Statement
TEPS – Threatened, Endangered, Proposed, and Sensitive
USDA – United States Department of Agriculture
VAM – Ventilation air methane

Contents

Executive Summary

The following sections summarize the contents of the Regulatory Impact Analysis (RIA) for the North Fork Coal Mining Exception of the Colorado Roadless Rule. The summaries are displayed according to the nine key elements suggested by the Office of Management and Budget (OMB) Office of Information and Regulatory Affairs (OIRA) guidance[1], which aims to assist agencies in developing RIAs, as required for economically significant rules by Executive Order (EO) 13563, 12866 Section 3(f)(1), and OMB Circular A-4. OMB has designated this final rule as economically significant.

(1) The Need for Regulatory Action

The overarching purpose and need for reinstating the North Fork Coal Mining Area exception is the same as the 2012 purpose and need statement for the Rule. However, the specific purpose and need for reinstating the North Fork Coal Mining Area exception is to provide management direction for conserving about 4.2 million acres of Colorado roadless areas (CRAs) while addressing the State's interest in not foreclosing opportunities for exploration and development of coal resources in the North Fork Coal Mining Area.

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[1] *Office of Management and Budget, Office of Information and Regulatory Affairs. (2011). Regulatory Impact Analysis: A Primer* *https://www.whitehouse.gov/sites/default/files/omb/inforeg/regpol/circular-a-4_regulatory-impact-analysis-a-primer.pdf*

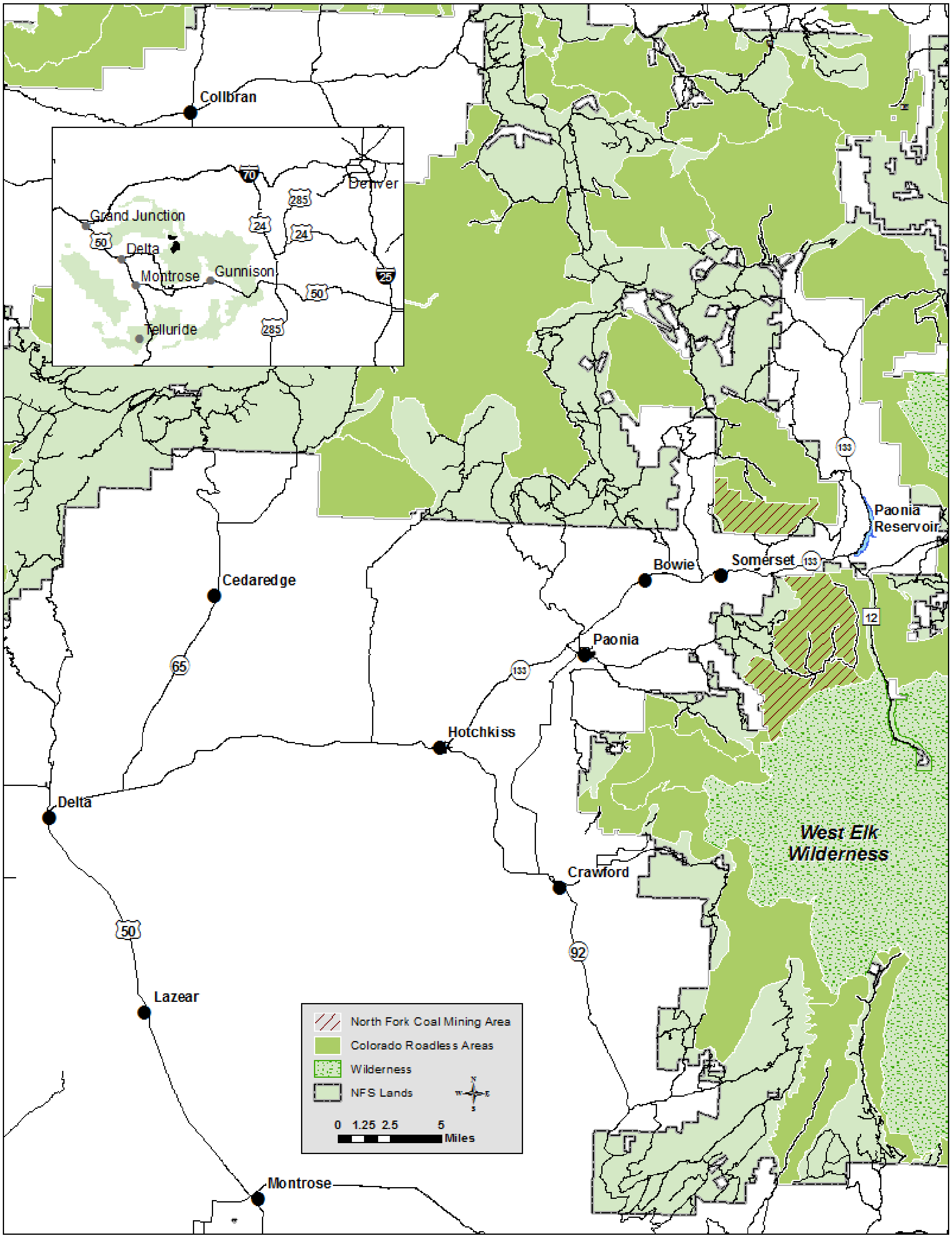


Figure ES-1. *Location of North Fork Coal Mining Area.*

(2) Baseline

The baseline, or the no action alternative, is required by the National Environmental Policy Act (NEPA) and reflects continuation of current management consistent with the District Court of Colorado ruling to vacate the North Fork Coal Mining Area exception to the Colorado Roadless Rule. The District Court of Colorado's ruling changed only management of CRAs in the North Fork Coal Mining Area; the remainder of the rule was left intact. Currently, the North Fork Coal Mining Area is being managed the same as non-upper tier CRAs. Rights to coal and uses associated with existing coal leases continue in accordance with the terms and conditions of those leases. This alternative would continue current management, with the general prohibitions on tree cutting, sale, and removal; road construction/reconstruction; and use of linear construction zones (LCZs) within CRAs, with some of those activities permitted under certain exceptions as defined in 36 CFR 294 Subpart D.

(3) Time Horizon of Analysis

For the Cost-Benefit Analysis, coal production timeframe varies by alternatives (**Table ES-1.**), ranged from one to 35 years (from 2016 to 2054), dependent upon the estimated schedule of gross North Fork Coal Mining Area extraction.

Table ES-1. *Estimated schedule of gross North Fork Coal Mining Area extraction (millions of short tons)*

Production Rate	Beginning Year (Production)	Ending Year (Production)	Total Years	Total Production (millions of tons)
Alternative A				
Low Scenario	*2016 (5)*	*2018 (0.8)*	*2*	*11*
Average Scenario	*2016 (10)*	*2017 (1)*	*1*	*11*
Permitted Scenario	*2016 (11)*	*---*	*1*	*11*
Alternative B				
Low Scenario	*2016 (5)*	*2051 (2)*	*35*	*184*
Average Scenario	*2016 (10)*	*2034 (4)*	*18*	*184*
Permitted Scenario	*2016 (15)*	*2027 (13)*	*11*	*184*
Alternative C				
Low Scenario	*2016 (5)*	*2036 (2)*	*20*	*106*
Average Scenario	*2016 (10)*	*2026 (6)*	*10*	*106*
Permitted Scenario	*2016 (15)*	*2022 (13)*	*6*	*106*

(4) Range of Regulatory Alternatives

The Secretary of Agriculture will decide whether to reinstate the North Fork Coal Mining Area exception and on what areas the exception could be applied. The decision involves a choice among the three alternatives analyzed in detail to address Court-identified deficiencies in the SFEIS, which means determining whether to do one of the following:

1. Take no action. No North Fork Coal Mining Area exception would be promulgated. CRAs would be managed according to the Colorado Roadless Rule without the exception, and the North Fork Coal Mining Area would be managed the same as other non-upper tier acres. (Alternative A).

2. Promulgate the North Fork Coal Mining Area exception and apply it to about 19,700 acres of CRAs (Alternative B).
3. Promulgate the North Fork Coal Mining Area exception and apply it to about 12,600 acres of CRAs (Alternative C).

In addition, all three of the alternatives will correct three CRA boundaries by aligning the North Fork Coal Mining Area boundary with CRA boundaries.

(5) Consequences of Regulatory Alternatives

Per OMB guidance, agencies should identify the potential benefits and costs for each alternative and its timing. Benefits and costs can be identified in the following manner: (i) benefits and costs that can be monetized, and their timing; (ii) benefits and costs that can be quantified, but not monetized, and their timing; (iii) benefits and costs that cannot be quantified. In order to address court-identified deficiencies in the 2012 Final Environmental Impact Statement (FEIS), boundaries of the analysis are expanded beyond traditional Forest-level boundaries; Forest boundaries are more consistent with agency policy for economic analysis. This Executive Summary estimates benefits, costs, and present net values at the global level due to the global nature of climate change and to capture the impact of domestic actions on global populations. Monetized benefits and costs under the Global Boundary include:

- Benefits are represented by (i) domestic power generation cost savings resulting from increased North Fork Coal Mining Area coal resources (accounting for substitution), and (ii) the net value of coal exports resulting from North Fork Coal Mining Area production (accounting for domestic substitution, but not foreign substitution). No effort was made to capture the benefits of potential power generating efficiency gains in foreign countries.
- Social costs are represented by the aggregate SCC value of carbon dioxide emissions from (i) net coal and natural gas production, coal transportation, and domestic coal and natural gas consumption (accounting for substitution), and (ii) coal exported, including overseas transport and consumption for electric power (accounting for domestic substitution but not foreign substitution effects). The benefits of coal consumption include electricity generated as a result of that consumption; however, for this analysis, the amount of electricity generated is assumed to remain constant across alternatives (see discussion of IPM modeling framework in Appendix C of the SFEIS). Changes in electricity generation are therefore not used to characterize benefits; instead, reductions in cost to achieve fixed levels of electricity demand are the basis for describing benefits.

In sum, downstream combustion, transportation, and market substitution effects are estimated and disclosed under the Global stance adopted for this analysis. Benefits and costs were not quantified or monetized for the overall 2012 Colorado Roadless Rule in the 2012 RIA, and as a consequence it is not possible to compare discounted benefits, costs, and present net values from this regulatory action with benefit cost results for the overall 2012 Colorado Roadless Rule. (Per Forest Service policy (FSM 1970 and FSH 1909.17), the term “Present Net Value” used throughout this document is defined as “the present benefit value (PVB) of the stream of benefits less the present cost value (PVC) of the schedule of costs.) The overall 2012 Colorado Roadless Rule discussed a broad spectrum of benefits and costs associated with use and access to forest resources across in comparison to roadless area characteristics across 4.2 million acres of NFS lands. In contrast, this regulatory action addresses the benefits and costs of reinstating exceptions for coal mining on 19,500 acres of roadless areas.

The RIA provides a separate description of distributional effects (contributions to jobs in the local economy) separate from the benefit cost analysis (consistent with OMB Circular A-4). Output, employment, and labor income impacts in the economic impact area from estimated coal production within the North Fork Coal Mining Area are estimated using an Input-Output model. Only those impacts associated with potential development and production of coal from the North Fork Coal

Mining Area are included. Direct effects are realized by the extraction and sale of coal. Indirect effects are realized by local companies that provide goods and services to coal mining operations. Induced effects result from local spending of employee income paid by the companies directly and indirectly affected by mining activities.

Agency costs are not expected to change across the alternatives. Potential changes in agency costs associated with road construction, road maintenance, and invasive plan management and control were addressed qualitatively in the RIA for the 2012 Colorado Roadless rule. A majority of those costs were expected to be associated with potential changes in forest or vegetation treatment projects, and unlikely to change due to expectations that program budgets for those activities would remain relatively flat. Reinstatement of the North Fork coal mining exception (Alternative B), or portions thereof under Alternative C, are not expected to alter those conditions or result in changes in treatments. As a result, substantial changes in agency costs are not expected to occur as a result of this regulatory action.

(6) Quantifying, Monetizing and (7) Discounting Benefits and Costs

Distributional impacts as well as Present Net Value (PNV) results are summarized below (

Table **ES-2**). A range of PNV results are provided to demonstrate the effects of different (i) discount rates (2.5%, 3%, and 5% - consistent with SCC guidance), (ii) coal mine production rates (low, average, and permitted (highest)), and (iii) IPM modeling scenarios reflecting variations in assumptions about projected energy production and power generation market and regulatory projections.

Table ES-2. *Distributional Impacts and Cost-Benefit Analysis Results*

Issue or Affected Resource	*Alternative A: No Action with CRA Boundary Corrections*	*Alternative B: Proposed Action Reinstatement of North Fork Coal Mining Area with CRA Boundary Corrections*	*Alternative C: Exclusion of "Wilderness Capable" Lands from proposed North Fork Coal Mining Area with CRA Boundary Corrections*
Distributional Effects			
Value of production (annual average), in millions	$37	$254 – 598	$254 – 598
Employment (annual average), in number of jobs	140	985 – 2,320	985 – 2,320
Labor income (annual average), in millions	$11	$78 – 183	$78 – 183
Cost-Benefit Analysis Present Net Value (millions of 2014 dollars)			
IPM® v.5.15[2] Social Cost of Carbon and Social Cost of Methane (millions of 2014 dollars)			

[2] EPA uses IPM to analyze the impact of air emissions policies on the U.S. electric power sector. As part of this analysis, EPA publishes its assumptions and other information regarding its use of IPM on its website. Although this documentation provides insight into EPA's assumptions, the data and assumptions used by the Forest Service in this analysis are not necessarily the

Issue or Affected Resource	*Alternative A: No Action with CRA Boundary Corrections*	*Alternative B: Proposed Action Reinstatement of North Fork Coal Mining Area with CRA Boundary Corrections*	*Alternative C: Exclusion of "Wilderness Capable" Lands from proposed North Fork Coal Mining Area with CRA Boundary Corrections*
Global Boundary	Alternative A	Alternative B - Alternative A	Alternative C - Alternative A
Lower Estimate*	Due to the use of electric power generation cost savings as a proxy for benefits, results are provided only for Alternatives B and C, relative to Alternative A (i.e., cost savings cannot be characterized for stand-alone alternatives).	-$3,440	-$1,878
3% Discount Avg. (Lower)**		-$964	-$506
3% Discount Avg. (Upper)**		-$479	-$214
Upper Estimate*		$206	$190

See Table C-34 of the SFEIS Appendix C for detailed SCC and SCM results for all assumptions.
**Lower and upper estimates are drawn from results from all production schedules (low, average, permitted).*
***Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.*

While OMB guidance suggests presenting the estimated results using both 3% and 7% discount rates, the 7% rate was not used because it is not compatible with the predetermined rates set forth by the Interagency Working Group (IWG) SCC protocol.

Table ES-2a. *Annualized benefits and social costs of net carbon dioxide and methane emissions (millions of 2014 dollars) under IPM® v5.15 (SFEIS)*

	Alternative B – Alternative A		*Alternative C – Alternative A*	
	Benefits	Social Costs	Benefits	Social Costs
Global Boundary				
Lower Estimate	$19	-$177	$12	-$98
3% Discount Avg. (Lower)	$19	-$63	$12	-$35
3% Discount Avg. (Upper)	$36	-$58	$24	-$34
Upper Estimate	$35	-$23	$26	-$14

Annualized values apply over 36 year period (based on the longest period of time needed to exhaust North Fork coal mining area supplies under the 'low' production scenario. A 3% discount range is assumed, consistent with SCC and SCM values associated with these results; exceptions being rates of 5% for the upper estimate for the global boundary.

(8) Non-quantified and Non-monetized Benefits and Costs

Other environmental consequences are discussed and disclosed non-monetarily in the SFEIS. Table ES-3 summarizes some of those considerations:

same as used by EPA. However, the Forest Service did use many of the EPA assumptions as described in more detail in Section 1.2 of documentation available in the planning record (ICF, 2015a). Because of these similarities, this analysis uses IPM nomenclature (5.13 and 5.15) similar to EPA. Use of this nomenclature is not meant to indicate that the Forest Service has used IPM in the exact manner as EPA. See Appendix C of the SFEIS for more detail regarding the Forest Service's use of IPM.

Table ES-3. *Non-monetized Benefits and Costs*

Issue or Affected Resource	*Alternative A: No Action with CRA Boundary Corrections*	*Alternative B: Proposed Action Reinstatement of North Fork Coal Mining Area with CRA Boundary Corrections*	*Alternative C: Exclusion of "Wilderness Capable" Lands from proposed North Fork Coal Mining Area with CRA Boundary Corrections*
Air Resources - GHG Emissions			
Cumulative GHG emissions (metric tons CO_2e); includes methane	Not Applicable (unleased coal resource inaccessible with current technology and thus no additional GHG emissions, existing leases part of the environmental baseline)	443 million	244 million (assumed to be produced at the same rate per year as Alternative B)
Cumulative methane emissions (metric tons CO_2e)	Not Applicable (unleased coal resource inaccessible with current technology and thus no additional methane emissions, existing leases part of the environmental baseline)	34 million	19 million
Climate	Unleased coal resources inaccessible, thus no additional GHG emissions beyond the environmental baseline; Climate change part of the environmental baseline	Greatest increase in GHG emissions among all alternatives. Greatest increase in atmospheric concentrations of GHGs.	Increase in GHG emissions and atmospheric concentrations more than Alternative A and less than Alternative B
Threatened, Endangered, and Sensitive Species			
No effect	Black-footed ferret, Colorado butterfly plant, grey wolf, grizzly bear, Lesser prairie-chicken, North Park phacelia, Osterhout milkvetch, Pagosa skyrocket, Penland beardtongue, southwestern willow flycatcher (critical habitat), Uncompahgre fritillary butterfly, Ute ladies'-tresses, yellow-billed cuckoo (proposed critical habitat)		
May affect, not likely to adversely affect	Canada lynx, Colorado hookless cactus, greenback cutthroat trout, DeBeque phacelia (species), Gunnison sage-grouse, Mexican spotted owl (species and critical habitat), Pawnee montane skipper, Penland alpine fen mustard, Preble's meadow jumping mouse (species and critical habitat), southwestern willow flycatcher (species and critical habitat), yellow-billed cuckoo (species and critical habitat)		
May affect, likely to adversely affect	Bonytail chub, Colorado pikeminnow, humpback chub, razorback sucker		

(9) Uncertainty in benefits, costs, and net benefits

Regulatory analysis requires forecasts about the future. What the future holds, both in the baseline and under the regulatory alternative under consideration, is typically not known for certain. The important uncertainties connected with the regulatory decision should be analyzed and presented as part of the overall regulatory analysis. As suggested by OMB's guidance on RIAs, the goal of the agency's uncertainty analysis is to present both a central "best estimate," which reflects the expected value of the benefits and costs of the rule, as well as a description of the ranges of plausible values for benefits, costs, and net benefits, which informs decision-makers and the public of the degree of uncertainty associated with the regulatory decision. The SFEIS (2016) and this RIA recognize the substantial uncertainties associated with efforts to characterize net benefits that account for GHG emissions. It is important to stress that while the concept of PNV attempts to compare the benefits and costs of a decision to society; the analysis presented in this RIA is illustrative in nature, portraying possible cumulative effects of rulemaking, based on available information and technical support.

Estimates under each alternative stemmed from three possible production schedules and multiple series of SCC values (from 3 different discount rates, etc.). Understandably, this gave rise to an expansive range of results. The **Error! Reference source not found.** provides further sensitivity analyses by evaluating the effects of different assumptions about several inputs on benefit and cost results:

- Substitution response factors based on different Integrated Planning Model (IPM) scenarios,
- Fixed demand and percent of North Fork Coal Mining Area coal production subject to substitution,
- Coal values as affected by coal mine costs, and
- Power generation cost savings.

Each of these four assumption areas were adjusted to demonstrate potential sensitivity of PNV results under IPM® v5.13 to baseline assumptions. Updated results using the newer IPM® v5.15—are presented in Chapter 3. Estimates of discounted net benefits and costs from different input and boundary stance assumptions are presented in Chapter 3 of this RIA and Appendix C of the SFEIS.

Chapter 1 Purpose of and Need for Action

The overarching purpose and need for reinstating the North Fork Coal Mining Area exception is the same as the 2012 purpose and need statement for the Rule. However, the specific purpose and need for reinstating the North Fork Coal Mining Area exception is to provide management direction for conserving about 4.2 million acres of CRAs while addressing the State's interest in not foreclosing opportunities for exploration and development of coal resources in the North Fork Coal Mining Area.

The original Purpose of and Need for Action as articulated in the 2012 FEIS is as follows:

The Department, the Forest Service, and the State of Colorado agree that a need exists to provide management direction for conserving roadless area characteristics within roadless areas in Colorado. In its petition to the Secretary of Agriculture, the State of Colorado indicated a need to develop State-specific regulations for the management of Colorado's roadless areas for the following reasons:

- Roadless areas are important because they are, among other things, sources of drinking water, important fish and wildlife habitat, semi-primitive or primitive recreation areas that include both motorized and non-motorized recreation opportunities, and naturally appearing landscapes. A need exists to provide for the conservation and management of roadless area characteristics.
- The Department, the Forest Service, and the State of Colorado recognize that tree cutting, sale, or removal and road construction/reconstruction have the greatest likelihood of altering and fragmenting landscapes, resulting in immediate, long-term loss of roadless area characteristics. Therefore, there is a need to generally prohibit these activities in roadless areas. Some have argued that linear construction zones (LCZs) also need to be restricted.
- A need exists to accommodate State-specific situations and concerns in Colorado's roadless areas. These include:
    - reducing the risk of wildfire to communities and municipal water supply systems,
    - facilitating exploration and development of coal resources in the North Fork coal mining area,
    - permitting construction and maintenance of water conveyance structures,
    - restricting LCZs, while permitting access to current and future electrical power lines, and
    - accommodating existing permitted or allocated ski areas.
- There is a need to ensure that CRAs are accurately mapped.

Proposed Action

The proposed action (Alternative B) is to reinstate the North Fork Coal Mining Area exception as written in 36 CFR 294.43(c)(1)(ix) on 19,700 acres of NFS lands. The exception provides for temporary road construction and reconstruction for coal exploration and/or coal-related surface activities within the North Fork Coal Mining Area. The exception also provides that such roads may be used for collection/transport of coal mine methane. The exception defines that buried infrastructure, including pipelines, needed for the capture, collection, and use of coal mine methane could be located within the rights-of-way of temporary roads that are necessary for coal-related surface activities, including the installation and operation of methane venting wells subject to site-specific permitting. No upper tier acres are designated in the North Fork Coal Mining Area under this alternative. Upper tier acres are a subset of CRAs that have limited exceptions and receive a higher-level of protection than non-upper tier CRA acres.

Decision Framework

The Secretary of Agriculture will decide whether to reinstate the North Fork Coal Mining Area exception and on what areas the exception could be applied. The decision involves a choice among the three alternatives analyzed in detail to address Court-identified deficiencies in this SFEIS, which means determining whether to do one of the following:

1. Take no action. No North Fork Coal Mining Area exception would be promulgated. CRAs would be managed according to the Colorado Roadless Rule without the exception, and the North Fork Coal Mining Area would be managed the same as other non-upper tier acres. (Alternative A).
2. Promulgate the North Fork Coal Mining Area exception and apply it to about 19,700 acres of CRAs (Alternative B).
3. Promulgate the North Fork Coal Mining Area exception and apply it to about 12,600 acres of CRAs (Alternative C).

In addition, all three of the alternatives will correct three CRA boundaries by aligning the North Fork Coal Mining Area boundary with CRA boundaries.

Public Involvement

On November 20, 2015, a notice of proposed rulemaking and notice of availability for the Supplemental Draft Environmental Impact Statement (SDEIS) were published in the *Federal Register*, initiating the 45-day SDEIS comment period that was to end on January 4, 2016. On December 30, 2015, a notice extending the 45-day comment period by 11 days to January 15, 2016, was published in the *Federal Register*. The extension was based on requests from the public due to the 45-day comment period overlapping with the holiday season. In addition to the *Federal Register* notices, the Forest Service sent about 1,400 hard copy letters and 43,000 emails to individuals and organizations known to be interested in the Colorado Roadless Rule. About 104,500 letters were received during the SDEIS comment period and about 33,000 letters were received after the close of the comment period. In addition, two public open houses were held, one in Paonia, Colorado, and one in Denver, Colorado, on December 7 and 9, 2015, respectively, to allow the public to ask questions and clarify information on the proposal to reinstate the North Fork Coal Mining Area exception.

On April 7, 2015, a notice of intent to prepare a Supplemental Environmental Impact Statement (SEIS) was published in the *Federal Register,* which initiated the 45-day scoping comment period ending on May 22, 2015. In addition to the Notice of Intent, the Forest Service sent about 1,400 hard copy letters and 43,000 emails to individuals and organizations known to be interested in the Colorado Roadless Rule to solicit comments. About 119,400 comment letters were received. The letter received from the EPA has been included for review in Appendix D.

In addition to the public comment periods associated with the supplemental, there were five formal public involvement processes associated with the development of the 2012 Colorado Roadless Rule. These five efforts included 35 public meetings held throughout Colorado and in Washington D.C. and resulted in about 312,000 public comments.

Tribal Consultation

In addition to the outreach to the general public for comments on the Colorado Roadless Rule, the Forest Service contacted the three tribes most likely to be concerned or directly impacted by the proposed rule. Those tribes included the Ute, Ute Mountain Ute, and Southern Ute Tribes. The Forest Service sent background information on the proposal to reinstate the North Fork Coal Mining Area exception and offered government-to-government consultation meetings with each of the Tribes. The Tribes provided no formal comments and did not request any meetings.

Issues

The June 2014 District Court of Colorado's opinion in *High Country Conservation Advocates v. United States Forest Service* and public comments were used to identify key issues. Key issues are environmental issues that were studied in detail and were needed to make informed decisions in conjunction with the 2012 FEIS. The following key issues carried through the SFEIS analysis:

- **Greenhouse Gas (GHG) Emissions** – Public comments and the District Court of Colorado ruling suggested the need for a quantitative GHG analysis. Additional analyses related to GHGs were evaluated.
- **Climate Change** – The environmental issue behind the GHG emissions concern is climate change. The quantitative GHG emissions analysis was put into context of climate change for an informed decision.
- **Social Cost of Carbon** – Public comments and the District Court of Colorado ruling suggested the use of SCC estimates to evaluate costs of increased carbon dioxide emissions generated by the proposal. The SCC was used based on public comments and the Court ruling. (Analogous estimates of the social cost of methane (SCM) were used to monetize the climate impacts associated with increases in methane emissions generated associated with the Alternatives.)
- **Coal Economics** – Corrections and proposed changes to the North Fork Coal Mining Area boundary and changes in demographics/economic trends throughout the State of Colorado affect the 2012 estimated economic outputs. Additional economic modeling and data were considered to address new information for the coal resources.
- **Fisheries** – After a NEPA sufficiency review of the 2012 FEIS, it was determined that new information had emerged regarding the genetics of Colorado River cutthroat trout in the southern Rockies. Supplemental analyses addressed this new information and comments received from the public.
- **Federally Listed Threatened, Endangered, Proposed, and Sensitive Species** – After a NEPA sufficiency review of the 2012 FEIS, it was determined that several species listed, and critical habitat designated, under the Endangered Species Act (ESA) affect CRAs. In addition, the Regional Forester updated the sensitive species list in August 2013. Supplemental analyses were completed under the ESA, and consultation with the U.S. Fish and Wildlife Service was re-initiated for the entire Colorado Roadless Rule. The review under ESA is a statewide review of all 4.2 million CRA acres—an area that includes, but is not limited to, the North Fork Coal Mining Area.

Issues raised by the public and considered by the interdisciplinary team that are not to be key issues are described in pages 10–11 of the 2012 FEIS, Appendix B–Issues of the SDEIS, and Appendix E – Response to Comments of this SFEIS. Issues not considered to be key issues were not analyzed in detail because they were:

- General opinions or position statements not specific to the proposed action
- Items addressed by other laws, regulations, or policies
- Items not relevant to the potential effects of the proposed action, or otherwise outside the scope of this analysis.
- Other content of the 2012 FEIS, which informs, but is not repeated.

Chapter 2 The Range of Regulatory Alternatives

This chapter describes the three alternatives considered in detail, compares alternatives and describes alternatives dismissed from detailed study.

Alternative A: The No Action Alternative

This alternative is the no action alternative as required by NEPA and reflects continuation of current management consistent with the District Court of Colorado ruling to vacate the North Fork Coal Mining Area exception to the Colorado Roadless Rule. The District Court of Colorado's ruling changed only management of CRAs in the North Fork Coal Mining Area; the remainder of the rule was left intact. Currently, the North Fork Coal Mining Area is being managed the same as non-upper tier CRAs. Rights to coal and uses associated with existing coal leases continue in accordance with the terms and conditions of those leases. This alternative would continue current management, with the general prohibitions on tree cutting, sale, and removal; road construction/reconstruction; and use of LCZs within CRAs, with some of those activities permitted under certain exceptions as defined in 36 CFR 294 Subpart D.

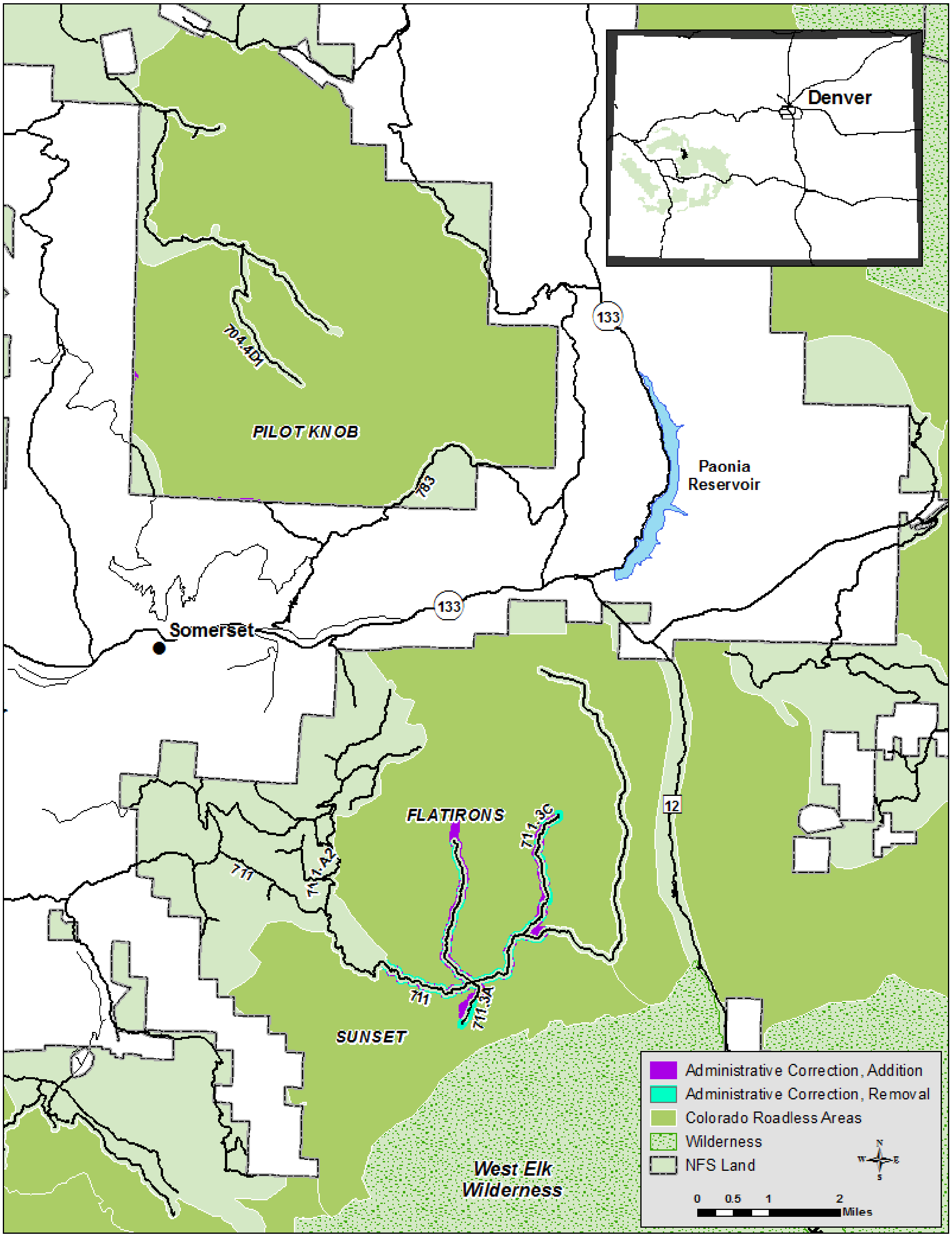


Figure 2-1. *Map of Alternative A, Colorado Roadless Areas near the analysis area with administrative corrections.*

Alternative B: Proposed Action & Preferred Alternative

Alternative B is the proposed action and preferred alternative (Fig. 2-2). This alternative would reinstate the North Fork Coal Mining Area exception as written in 36 CFR 294.43(c)(1)(ix). Specifically, the following clause would be reinstated:

> *A temporary road is needed for coal exploration and/or coal-related surface activities for certain lands within Colorado Roadless Areas in the North Fork coal mining area of the Grand Mesa, Uncompahgre, and Gunnison National Forests as defined by the North Fork coal mining area displayed on the final Colorado Roadless Areas map. Such roads may also be used for collecting and transporting coal mine methane. Any buried infrastructure, including pipelines, needed for the capture, collection, and use of coal mine methane, will be located within the rights-of-way of temporary roads that are otherwise necessary for coal-related surface activities including the installation and operation of methane venting wells.*

Alternative B would apply to an area similar to the North Fork Coal Mining Area described in the 2012 FEIS with minor differences described below.

North Fork Coal Mining Area Boundary Changes

Alternative B proposes to administratively change the North Fork Coal Mining Area boundary to align it to the CRA boundary and to resolve two errors that occurred during the development of the 2012 FEIS. These errors included:

- Changes to CRAs between the DEIS and revised DEIS: specifically, the CRA boundaries were updated but the corresponding match between the CRA boundary and North Fork Coal Mining Area boundary was not made, resulting in numerous inadvertent “slivers” along the boundary.
- Due to an error calculating acres made during the preparation of the 2012 FEIS, an area of about 470 acres was subtracted from the North Fork Coal Mining Area total acreage twice. With this error the final North Fork Coal Mining Area acreage was incorrectly reported as 19,100 acres in the FEIS but should have been reported as 19,500 acres. This error did not physically change the North Fork Coal Mining Area, but the correctly reported total acres increases.

The change to the North Fork Coal Mining Area boundary would entail:

- Adding 409 acres to align the North Fork Coal Mining Area with CRA boundaries.
- Removing 254 acres to align the North Fork Coal Mining Area with CRA boundaries.
- Total size of the North Fork Coal Mining Area would be about 19,700 acres.

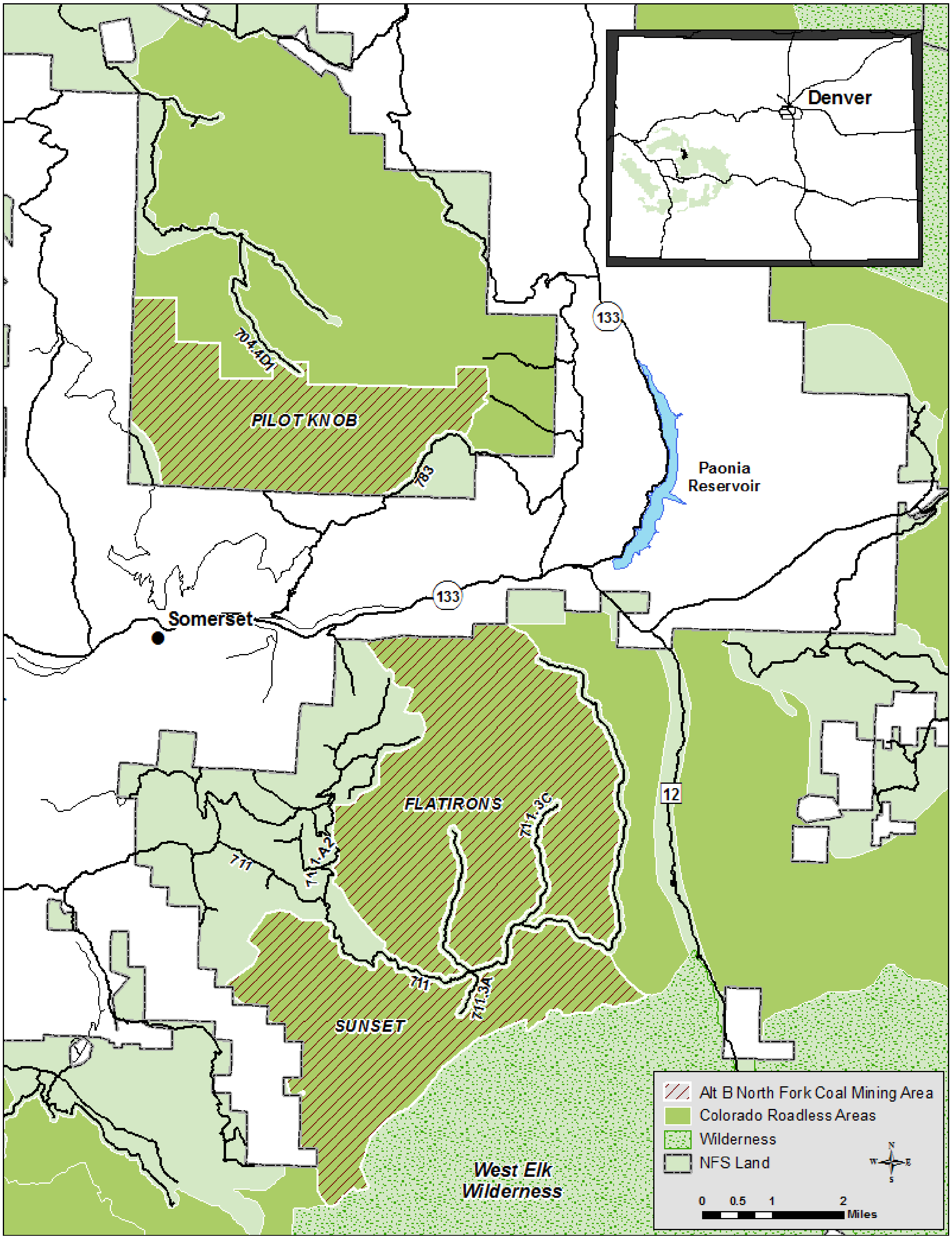


Figure 2-2. *Map of Alternative B, the North Fork Coal Mining Area.*

Alternative C: Reduced North Fork Coal Mining Area

Alternative C is similar to Alternative B in that it would reinstate the North Fork Coal Mining Area exception as written in 36 CFR 294.43(c)(1)(ix). Specifically, the following clause would be reinstated:

> *A temporary road is needed for coal exploration and/or coal-related surface activities for certain lands within Colorado Roadless Areas in the North Fork coal mining area of the Grand Mesa, Uncompahgre, and Gunnison National Forests as defined by the North Fork coal mining area displayed on the final Colorado Roadless Areas map. Such roads may also be used for collecting and transporting coal mine methane. Any buried infrastructure, including pipelines, needed for the capture, collection, and use of coal mine methane, will be located within the rights-of-way of temporary roads that are otherwise necessary for coal-related surface activities including the installation and operation of methane venting wells.*

North Fork Coal Mining Area Boundary Changes

Alternative C would apply to an area similar to that of Alternative B, except areas identified as "wilderness capable" in the 2007 GMUG Forest Plan revision effort would be excluded from the North Fork Coal Mining Area (Fig. 2-3). The North Fork Coal Mining Area under this alternative would be about 12,600 acres and would include no upper tier acres. Changes to the North Fork Coal Mining Area boundary would include administrative corrections to resolve the three errors described in the *Features Common to all Alternatives* section of this chapter and a boundary change to exclude the area identified as "wilderness capable."

During the 2007 GMUG plan revision effort, the capability of potential wilderness areas was defined as the degree to which that area contains the basic characteristics that would make it suitable for wilderness. Characteristics considered in the 2007 revision evaluation included:

- **Environmental** – the degree to which an area appears to be free from disturbance so that the normal biological processes continue and the degree to which the area provides a visitor opportunity for solitude and a sense of remoteness.
- **Challenge** – the degree to which the area offers visitors opportunity to experience adventure and self-reliance, often measured by physical character of the land (terrain and vegetation) and proximity to sights and sounds of developments and travel systems.
- **Manageability of boundaries** – consideration of the ability to manage the area as wilderness; factors considered are size, shape, and juxtaposition to external influences.
- **Special features** – the area's capability to provide other values such as geologic, scenic, or cultural features.

The Sunset Roadless Area, identified as "wilderness capable," was not recommended for wilderness in the 2007 GMUG revision effort due to mineral values and boundary management issues. The Flatirons Roadless Area, identified as "wilderness capable," was not recommended for wilderness in the 2007 GMUG revision effort because it was less than the minimum size of 5,000 acres. If selected, Alternative C removes these "wilderness capable" acres from the North Fork Coal Mining Area but would not recommend them for wilderness. Any future evaluations and further recommendations would be completed during the GMUG forest plan revision process.

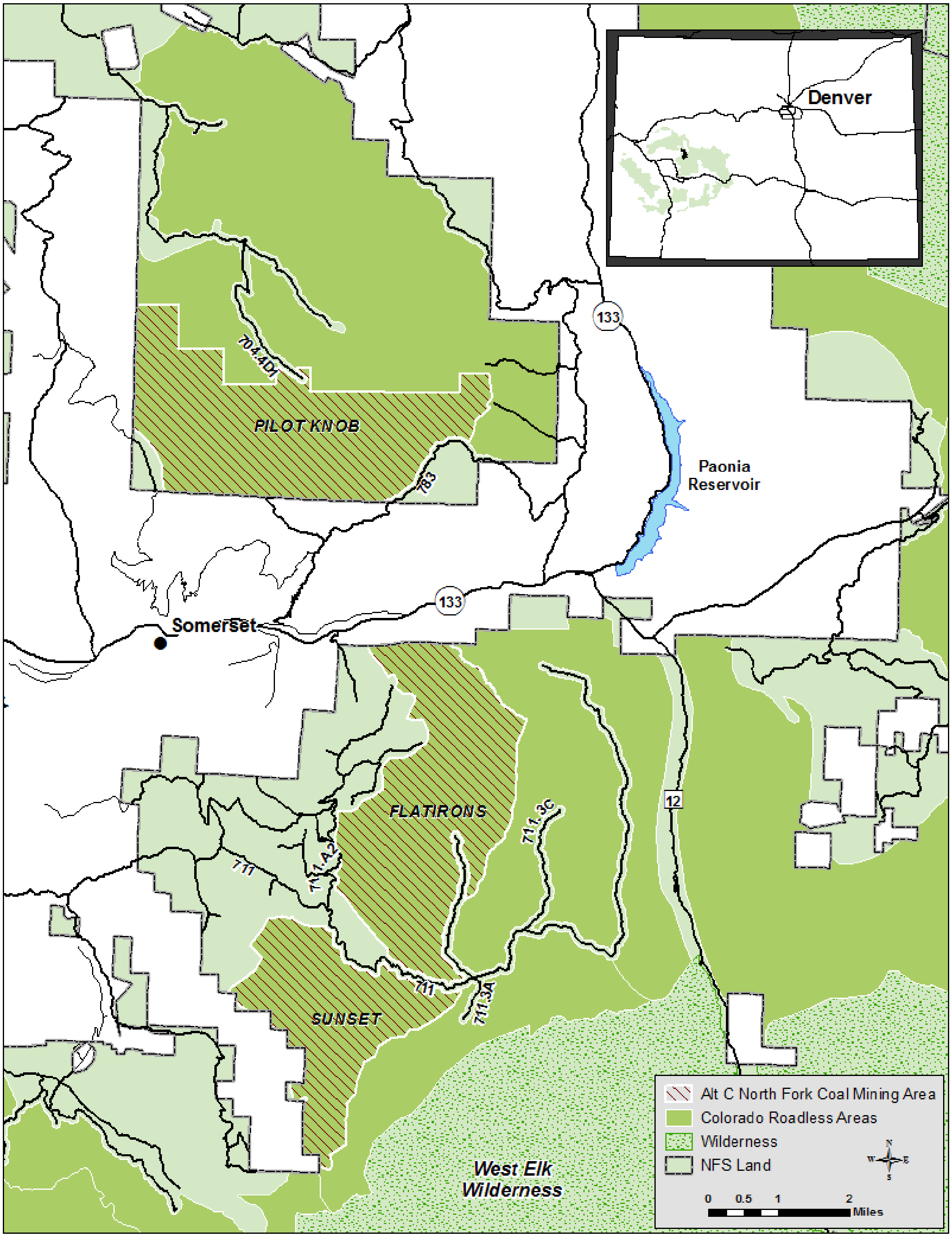


Figure 2-3. *Map of Alternative C, the North Fork Coal Mining Area excluding "wilderness capable" lands.*

Alternatives Considered but Eliminated from Detailed Study

NEPA regulations require Federal agencies to explore and evaluate all reasonable alternatives to a proposed action and to briefly discuss the reasons for eliminating alternatives from detailed study (40 CFR 1502.14). The alternatives listed below are based on comments received during scoping and the comment period on the SDEIS. The responsible official reviewed and weighed the following alternatives during the analysis process. The eliminated alternatives contribute to the range of reasonable alternatives and a reasoned choice, even though they were eliminated from detailed study. The following list describes the alternatives considered but eliminated from detailed study, and the reason(s) why these alternatives were eliminated from detailed study.

- **Methane (CH_4) capture and use or reduction.** This alternative would reduce methane emissions that could be released from coal mining made possible by the reinstatement of the North Fork Coal Mining Area exception by requiring or incentivizing use of "best available technology" to capture and/or combust methane for all or some percentage of the methane released. This alternative was dismissed from detailed analysis because it is speculative and impractical at the rulemaking stage where site-specific impacts are unknown and the necessary information to evaluate all the impacts and technology is not yet known or available. In addition, multiple future Federal and State agencies with expertise and authority over mine safety and mining operations will be better situated to realistically and meaningfully evaluate these technologies when a site-specific proposal is received. The scope of the decision being made in this rulemaking encompasses whether to allow temporary road construction in the North Fork Coal Mining Area for coal-related activities. The decision whether to apply a stipulation regarding methane capture and use or reduction is more appropriately made as part of a coal leasing or development decision. This decision does not foreclose any future lease stipulations related to methane capture and use or reduction. Temporary roads authorized under this exception may also be used for collecting and transporting coal mine methane, including any buried infrastructure, such as pipelines needed for the capture, collection, and use of coal mine methane.

  There are multiple unknown factors at the roadless rulemaking stage that affect whether and what technology can be used to capture and use or destroy methane that may be released from coal mining. Unknown factors that influence the choice of technology include but are not limited to coal gas content, coal seam thickness, coal seam permeability, rate of mining, extent of roof collapse, extent of floor heaving, amount and distribution above and below the mined seam, rock type above and below the mined seam, miner safety issues, and access to natural gas infrastructure and markets. Along with these variables, whether there will be existing infrastructure—such as pipelines or powerlines—that may be needed and if not in place, the cost and environmental effects of constructing this infrastructure would not be known until a site-specific project is proposed. In addition, the effects from additional on-site construction needed for any such technological use, such as compressors, pumps, larger well pads, etc., which could result in greater surface disturbance from the use of "best available technology" can only be evaluated at a site-specific stage. Discussions about hypothetical uses of "best available technology" for methane capture and reduction would not disclose useful information to the decision maker or the public at this roadless rulemaking stage.

  It is particularly speculative and impractical for the Forest Service to examine these issues in the context of the Colorado Roadless Rule when decisions about the use of methane reduction technologies are subject to overview by the Mine Safety and Health Administration, the agency responsible for miner safety. For example, although flaring has been an approved technology for methane reduction, the Mine Safety and Health Administration has not approved a flaring system for an active coal mine in the Western United States due to concerns about miner safety. It would be inappropriate for the Forest Service to develop an alternative at the rulemaking stage that requires flaring as a possible "best available technology" in the face of potential opposition from the agency responsible for ensuring miner safety.

Decisions about methane capture and reduction are also subject to approval and review by other Federal and State agencies vested with authority over coal mining and energy development. In the case of coal mining, the Department of the Interior through the BLM has statutory authority to manage the Federal coal resources under mineral leasing laws and is in a better position to address questions about these technologies. In contrast, the Forest Service has discretion on which lands it consents to be leased, and has the responsibility to provide stipulations for the protection of surface resources. While the Forest Service's limited authority does not mean that the Forest Service cannot look at methane capture and use or destruction, it implies the impracticality and inefficiencies of having the Forest Service do so in the context of a statewide roadless rule that establishes a regulation, and in the absence of a site-specific proposal. The Department of Interior actions, including Secretarial Order 3338 directing the BLM to conduct programmatic review of the entire Federal coal leasing program, or BLM's advance notice for proposed rulemaking for waste mine methane capture, use, sale, or destruction, will thoroughly analyze the multitude of issues involved by the BLM as they prepare the analysis and make decisions. The most efficient means of addressing the coal mine methane capture and reduction issue at this point is to allow the BLM review processes to address it.

The present analysis is limited to correcting the specific deficiencies identified by the District Court judge in the earlier litigation over the Colorado Roadless Rule. However, this narrowed scope does not change the character of the analysis nor does it turn the analysis into a site-specific rule on coal mining and how best to engage in coal mining. Rather, it merely preserves the potential for construction of temporary roads should those roads be necessary for coal exploration or surface uses related to development activities.

Attempts to regulate and prescribe activities at a site-specific level potentially affected by a broad-scale programmatic rule do not meet the purpose and need for the rule. It defeats the benefits of tiered decision making—particularly when these decisions are better informed by site-specific information and when multiple Federal and State agencies are involved. The Colorado Roadless Rule affects, among other things, water storage/delivery, hazardous fuels, oil/gas development, and developed ski areas. If the Colorado Roadless Rule were to address all major shortcomings related to those affected activities, the rule would not meet the original purpose and need and the ability to finely craft better decisions at the local level would be lost.

- **Require a carbon offset for coal extracted.** This alternative would require a mitigation measure to require lease stipulations on any coal originating from the North Fork Coal Mining Area to include a carbon offset. Under this alternative, any coal removed from the North Fork Coal Mining Area would require a reduction of GHGs elsewhere. This alternative was dismissed from detailed analysis because the requirement for a carbon offset is dependent upon the directed use of a national carbon offset market (cap-and-trade system). While there are several cap-and-trade markets in the United States—the use of which is not being foreclosed as an option with the exception—no federally required Federal cap-and-trade market exists.

  The directed use of a cap-and-trade system is beyond the scope of roadless area conservation and therefore does not meet the purpose and need for this rule. As stated earlier, this rulemaking effort is not a coal-mining regulation. It is a regulation to prescribe broad-scale programmatic direction for managing and preserving roadless area characteristics in the State of Colorado.

- **Require a "carbon fee."** This alternative would require a fee be paid (a commenter suggested $1 per pound of coal) and funds used to protect the U.S. eastern seaboard from rising oceans. This alternative was dismissed from detailed analysis because fees are already collected from Federal coal in the form of royalty payments. BLM's programmatic review of the Federal coal leasing program will likely address royalty payments. Portions of royalty payments are paid to the U.S. Treasury and a portion is paid to the state. How those funds are expended is outside the scope of the Forest Service's mission and does not meet the purpose and need for the Colorado Roadless Rule.

- **Limit sale of coal to Integrated Gasification Combined Cycle or Carbon Capture and Storage facilities.** This alternative would require a stipulation to limit the sale of extracted coal from coal leases within the North Fork Coal Mining area to facilities using Integrated Gasification Combined Cycle or Carbon Capture and Storage technologies. This alternative was dismissed from detailed analysis because expanding the scope of the Colorado Roadless Rule to regulations affecting coal markets is not consistent with a regulation that focuses on activities occurring on NFS lands and roadless area conservation, does not meet the purpose and need for this rule, and is beyond the scope of this rulemaking effort.
- **Factor GHG and climate effects when determining the value of coal.** This alternative would require the Forest Service to incorporate the costs of GHG emissions and the resultant climatic effects when determining the price of unmined coal. While this SFEIS will assume a value of coal for the purposes of the economic analysis and in the context of the SCC, this alternative was dismissed from further analysis because the price of coal is determined by market forces. Setting a price of coal is not within the scope of the project and does not meet the purpose and need of rulemaking effort. It is not within the authority of the Forest Service to value coal; that responsibility is in the purview of the Department of Interior.
- **Energy efficiency measures and renewable energy.** This alternative would require the Forest Service to direct its resources to energy efficiency measures, the development of NFS lands for renewable energy projects, and potential allowance of road construction in roadless areas for renewable energy projects. A broad across-the-board shift of resources is a matter of national policy and there is currently no policy directing such a broad shift of resources. In addition, this alternative was dismissed from further analysis because it is beyond the scope of this rule and does not meet the purpose and need for this rulemaking effort, which was to address the State's interest in not foreclosing exploration and development of coal resources in the North Fork Coal Mining Area.
- **Assist coal companies and local communities to switch to renewable energy.** This alternative would require the Forest Service to assist coal companies and local communities in transitioning to a renewable energy company. This alternative was dismissed from detailed analysis because it is beyond the scope of the rulemaking effort and does not meet the purpose and need for the Colorado Roadless Rule. However, other Federal agencies (Department of Commerce's Economic Development Administration, Department of Labor's Employment and Training Administration, Small Business Administration, and Appalachian Regional Commission) are working with communities impacted by the downturn in the coal economy to diversify regional economies, create jobs, and train displaced workers under the Partnerships for Opportunity and Workforce and Economic Revitalization (POWER) initiative.
- **Issuance of new coal leases based on bond obligations.** This alternative would require the Forest Service to not consent to new leases until final reclamation bond obligations are met from 50% of current leases. This alternative was dismissed from detailed analysis because it is beyond the scope of the rulemaking effort and does not meet the purpose and need for the Colorado Roadless Rule. Further, reclamation bonds are not tied to specific BLM-issued leases, but are a function of obligations under the State-issued coal mining permit, which can include operations involving multiple leases and privately held coal resources. A Federal coal lease grants rights to the coal in the lease and provides access to the surface subject to terms and conditions of the lease (including those that regulate surface use); however, a lease does not authorize mining or surface use. Rather, in the State-managed coal permitting process, a lease demonstrates a permittee's 'right-of-entry' to coal resources, and any mining or surface uses on the leased lands are subject to State approval through the permitting process along with

establishing reclamation bonding. Thus, while leases and permits are related, they are separate functions, and State-reclamation bonding is not tied to leasing actions.

- **Requirement of a $2.5 billion irrevocable bond.** This alternative would require mining companies to put up a $2.5 billion bond in which half would go the local communities in case the company went bankrupt. This alternative was dismissed from detailed analysis because it is beyond the scope for this project and does not meet the purpose and need for the Colorado Roadless Rule. In addition the Colorado Department of Natural Resources Division of Reclamation, Mining and Safety regulates and permits coal mining operations in the State of Colorado. This includes reclamation and bonding.
- **Exclusion of the Pilot Knob Roadless Area.** This alternative would remove the Pilot Knob Roadless Area, about 5,000 acres (about 25%) of the project area, from the North Fork Coal Mining Area. This alternative was dismissed from detailed analysis because the Colorado Roadless Rule is considering access to coal resources within the North Coal Mining Area over the long-term based on where recoverable coal resources might occur. The Rule preserves the option of future coal exploration and development by allowing temporary road construction for coal exploration and coal-related surface activities. One of the State-specific concerns is the stability of local economies in the North Fork Valley and recognition of the contribution that the coal industry provides to those communities. Preserving coal exploration and development opportunities in the area is a means of providing community stability.
- **Increased upper tier acreage.** This alternative would include the reclassification of more acreage in the Colorado Roadless Rule as upper tier. Upper tier areas are CRAs with limited exceptions to provide a higher level of protection. This alternative was dismissed from detailed analysis because the July 2012 final Colorado Roadless Rule designated 1,219,200 acres as upper tier after careful consideration, which included five formal public input periods that generated 312,000 public comments. The USDA, at this time, does not see a need to revisit the decision on upper tier acres and is dismissing this alternative from detailed study because resources or forest uses have not substantially changed since the 2012 FEIS to warrant reconsideration. None of the CRA acres within the North Fork Coal Mining Area are upper tier acres.
- **Increased recreational opportunities rather than industrial use.** This alternative would open the North Fork Coal Mining Area to development of recreational opportunities, such as hiking and biking trails, instead of the potential development of mineral resources. This alternative was dismissed from detailed analysis because this option is not foreclosed by the Colorado Roadless Rule. The decision to construct trails and other recreational facilities in the area is a forest plan- or project-level decision, not a Departmental decision. The promulgation of this rule does not limit the future site-specific decisions that may lead to the development of recreational opportunities in the North Fork Coal Mining Area. Therefore, this alternative is beyond the scope of this rulemaking effort.

Chapter 3 Benefit-Cost Analysis

Although the reinstatement of the North Fork Coal Mining Area exception does not authorize or permit any coal exploration or development activity, or result in any ground-disturbing activity, the act of removing prohibitions of temporary road construction would facilitate access to federal coal resources in the North Fork Coal Mining Area. This accessibility in turn could facilitate future exploration and development. Because no ground-disturbing activities will be authorized as a result of this decision, there are no direct impacts associated with the action. This chapter discloses the indirect impacts that might result should coal be produced from the mines within the North Fork Coal Mining Area under the three alternatives.

This analysis is based on the accessibility to coal resources. It is unknown how much, where, and when coal resource exploration or coal-related surface activities might occur. For the purposes of analysis and disclosure, it is assumed that all of the estimated recoverable coal resources would be recovered across the entire North Fork Coal Mining Area. This represents the maximum effects that could occur.

In addition, this analysis assumes the coal would be recovered at a steady rate until exhausted. Three assumed production scenarios were used to facilitate analyses: low scenario (~5.3 million tons annually) based on 2014 production rates; average scenario (~10 million tons annually) based on average annual production from 2001 to 2014; and permitted level scenario (15 million tons annually) based on the maximum rates authorized under current air quality permits administered by the State of Colorado. Although the permitted-level scenario would be allowed by air quality permits, based on historical production, it is unlikely that coal would ever be produced at this rate. This scenario is included as an upper limit for the analysis.

The descriptions of effects are based on best available information available at the time of this analysis, programmatic projections and assumptions, and professional judgement and show relative values. Specific amounts, areas, and costs used to describe effects are only estimates and could change during implementation of the rule.

The economic analysis considers how the availability or absence of North Fork Coal Mining Area coal in the energy supply market might affect the mixture of energy sources used to generate electricity within the U.S. electricity market, and assesses the net impact on carbon dioxide emissions that might result from those changes.

This analysis supplements the 2012 FEIS economic analysis to address new information and changed circumstances that have occurred since the Colorado Roadless Rule became effective on July 12, 2012. The sections that follow describe the economic study area, the methods used to analyze economic effects, the affected environment, and the potential economic effects that could result under the three alternatives. There are two distinct economic effects analyses presented in this RIA:

- Chapter 3: Efficiency analysis, which estimates the value of benefits and costs to society as a whole.
- Chapter 4: Impact or distributional analysis, which estimates employment and income effects to the local study area and

The results of these two distinct analyses are presented separately because they serve different purposes, as described above. They are neither interchangeable nor can they be aggregated.

Many uncertainties exist regarding the potential for future coal extraction. Because this decision will not authorize any ground-disturbing activities, any additional coal-related development on unleased lands would need to be authorized under a subsequent decision that would require additional NEPA analysis. It is not known when or how much development might occur, particularly when considering activities that might occur well into the future. In order to estimate possible economic effects, many assumptions about future development activities were made that may not come to fruition. Therefore, the economic analysis presented here should be considered estimates based on best available data to compare between alternatives, not predictions of what will actually occur.

Analysis Methods and Assumptions

Scope of Analysis

The scope of this analysis is specific to the North Fork Coal Mining Area as defined in the Colorado Roadless Rule. Discussions of benefit and cost analysis are provided to respond to questions associated with Court-identified deficiencies associated with the original rulemaking; benefit and cost analysis discussions extend the scope and methodology of this economic study well beyond the traditional scope of benefit and cost analysis performed for public land-use decisions and are not required by NEPA (40 CFR 1502.23). Presentation of benefit and cost analysis for this programmatic action is not intended to establish precedence for the general application of these approaches to mineral leasing or other project-level decisions. The other resources discussed in the economic analysis of the 2012 FEIS do not require supplemental analysis.

Existing Conditions and Gross North Fork Coal Production

The following analysis and discussion of both economic impacts to the local area and the benefits and costs to society begin with assumptions about future schedules of coal mine production. These projections determine the extent to which temporary road construction or reconstruction could be permitted, but make no determinations about coal activity on specific NFS lands. However, this supplemental analysis assumes that temporary road construction permissions could result in changes in coal resources accessible under leases, and changes in future production of coal from NFS lands. In reality, any coal activity would require additional project-level decisions based on additional project-specific NEPA analysis.

Data sources include Colorado Department of Local Affairs; State Demography Office, U.S. Census Bureau; Energy Information Administration; Colorado Division of Reclamation, Mining and Safety; Headwaters Economics Human Dimension Toolkit; IMPLAN (IMpact Analysis for PLANning) model; and from the IPM model.

The most recent economic data available for this analysis are from 2013. Economic conditions in the local study area have changed since that time and therefore may not fully reflect conditions in 2016. This supplemental analysis focuses on the relative differences so that alternatives can be compared using the best available datasets.

Production of recoverable coal has been estimated using the low, average, and permitted production scenarios of coal output based on production data from past mine activity, existing permits, and estimates of recoverable coal resources (see SFEIS, *Coal Resources* section for details). While future mining activity is not known, the three production scenarios have been projected to serve as reasonable estimates. Annual outputs within each of the three scenarios are kept consistent over time until coal resources are exhausted, so the ending year varies across the three scenarios. The 2012 FEIS assumed three coal mines would be operating in the North Fork Coal Mining Area. For this supplemental analysis, past and current data are being used from existing mines, but no assumption is made of the number of mines that may be operating or could bid on future leases within the North Fork Coal Mining Area.

Aggregate annual coal production rates are assumed to be constrained by any individual mine operation and permitted capacity, implying that the period of time to extract the coal within the North Fork Coal Mining Area would vary as a function of the amount of coal resources made available under each alternative. The projected schedules of gross North Fork Coal Mining Area coal mine production under the low, average, and permitted production scenario, necessary to exhaust accessible reserve amounts under each alternative, are shown in Table 3-1.

Table 3-1. *Estimated schedule of gross North Fork Coal Mining Area extraction (millions of short tons)*

Production Rate	*Beginning Year (Production)*	*Ending Year (Production)*	*Total Years*	*Total Production (millions of tons)*
Alternative A				
Low Scenario	*2016 (5)*	*2018 (0.8)*	*2*	*11*
Average Scenario	*2016 (10)*	*2017 (1)*	*1*	*11*
Permitted Scenario	*2016 (11)*	*---*	*1*	*11*
Alternative B				
Low Scenario	*2016 (5)*	*2051 (2)*	*35*	*184*
Average Scenario	*2016 (10)*	*2034 (4)*	*18*	*184*
Permitted Scenario	*2016 (15)*	*2027 (13)*	*11*	*184*
Alternative C				
Low Scenario	*2016 (5)*	*2036 (2)*	*20*	*106*
Average Scenario	*2016 (10)*	*2026 (6)*	*10*	*106*
Permitted Scenario	*2016 (15)*	*2022 (13)*	*6*	*106*

Benefits and Social Costs Methodology

Unlike the economic impact analysis, which estimates the regional job and income impacts, this section considers the potential costs or damages of GHG emissions and climate change at the global scale. It was not feasible to quantify the global benefits of coal consumption for global populations (only domestic populations).

This analysis assesses the benefits and costs of offering additional coal leases in the North Fork Coal Mining Area if the exception is reinstated allowing access (see SFEIS, *Minerals* section for details about specific mining operations and production). The *Existing Conditions and Gross Production* section contains assumptions about the schedule and magnitude of annual coal production and continued mine production.

Overview of Benefit-Cost Framework

This discussion of potential benefits and costs focuses on estimating the discounted PNV of increased accessibility of North Fork Coal Mining Area bituminous coal (via temporary road construction/reconstruction) through the Federal mineral leasing program. PNV is used as an indicator of financial efficiency, or a partial economic efficiency of a project; it represents one factor to be used in conjunction with many other factors in the decision-making process. Note that it is Forest Service policy (FSM 1970 and FSH 1909.17) to define “Present Net Value” as “the present benefit value (PVB) of the stream of benefits less the present cost value (PVC) of the schedule of costs. It can be expressed in the following equation: PNV = PVB – PVC” (FSH 1909.17, Chapter 10). As such, this definition (PNV) is analogous to the term “Net Present Value.” PNV combines a project's benefits and costs that occur throughout the life of the project and discounts them into an amount that is equivalent to all economic activity in a single year. According to traditional Forest Service terminology, a positive PNV indicates that the alternative is financially efficient. A PNV analysis is not intended to be a comprehensive analysis that incorporates all known market and non-market benefits and costs. Many of the values associated with a natural resource management project are best handled apart from, but in conjunction with, a limited PNV framework. The non-market benefits and costs associated with this project are discussed throughout the various resource sections of the SEIS and 2012 FEIS.

The remaining text in this section describes how benefits and social costs are characterized in the monetized benefit-cost analysis. The *Non-monetized social costs* section describes other social costs not accounted for in the monetized benefit-cost analysis. Chapter 2 summarizes effects to all resources, including resources such as wildlife that are not included in the monetized benefit-cost analysis.

This analysis assumes that increased accessibility to North Fork Coal Mining Area coal resources could result in continued production and consumption (electricity generation) of North Fork Coal Mining Area coal over an extended period of time that varies across alternatives. Estimates of net benefits (represented by the term PNV) in this benefit-cost analysis are assumed to be based on the benefits (i.e., net coal value to producers; changes in efficiency of electric power provision to consumers) and the social costs (i.e., potential damages of carbon dioxide and methane emissions from changes in production, transportation, consumption, and export of coal) of continued production and consumption of North Fork Coal Mining Area coal.

Traditional benefit and cost analysis for Forest Service actions concentrates on the benefits and costs to the public of making lands or resources available for alternative uses. These analyses customarily characterize benefits and costs of resource use or extraction within NFS lands, where the Forest Service has the regulatory ability to manage and mitigate activities and effects (both beneficial and adverse). Benefits can be described in terms of willingness-to-pay for use of, or access to resources (e.g., minerals, forage, timber stumpage) on NFS lands. Likewise, costs can be described for ancillary adverse effects or damages that occur as a direct result of actions taken to use or access the forest.

It is rare that the Forest Service would incorporate indirect benefits and social costs of downstream uses of resources extracted or derived from National Forest lands as a result of the permitted activity, into a benefit-cost analysis because:

- The efficiency or effectiveness of downstream resource use (and therefore the benefits and costs of downstream use) will vary, is driven by complex markets, and is beyond the administrative control of the Forest Service, and
- Other non-Forest Service rules, regulations, policy, or institutions are in place to manage and mitigate potential social damages of downstream uses, in the interest of public welfare.

For example, the Forest Service relies on estimates of the stumpage value of timber removed from a National Forest for analyses of the benefits of timber harvests, but does not attempt to incorporate the value of finished wood products into benefit and cost analysis. To incorporate downstream wood product values would require the agency to make assumptions about types and efficiency of mills. Stumpage values may be calculated from information about downstream revenue and anticipated harvest costs (e.g., residual value stumpage appraisal method); however, those downstream revenues are not used to represent benefits in benefit-cost analyses.

Likewise, the Forest Service does not estimate the potential damages of wastewater effluent from downstream wood processing facilities; to do so would require the agency to assume that existing rules and policy put in place by other institutions (water quality standards and effluent guidelines) are *not sufficient* to mitigate the damages of wastewater in the interests of the public. For example, a decision to not allow a timber sale based on perceived downstream damages from increased wastewater effluent from processing plants, even if those plants are in compliance with existing wastewater regulations, implies that the Forest Service assumes additional wastewater controls (i.e., not allowing timber sale) are needed to adequately mitigate downstream damages. The same situation applies in the case of downstream coal-fired electric generation facilities, with air emissions that are in compliance with existing regulations, and using coal extracted from NFS lands. Even if existing rules and policy are perceived as being inadequate, it is difficult for the Forest Service to adopt an implicit regulatory role for mitigating downstream damages or beneficial uses for which it has limited or no legal basis.

In order to address Court-identified deficiencies in the 2012 FEIS, GHG emissions from combustion of coal under this programmatic action have been examined in this analysis, including benefits and social costs for downstream uses of resources. The boundaries of the analysis are therefore expanded beyond that of the typical Forest Service benefit and cost analysis (described in Forest Service Handbook for economic analysis FSH 1909.17, 10) to address downstream benefits and costs. This analysis is presented for informational purposes and results need to be carefully considered within the context of the uncertainty and assumptions necessary to estimate benefits and costs for this particular decision.

In this analysis the climate change related impacts of the estimated GHG emissions are monetized using the estimates of the social cost of carbon (SCC), recommended by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases for use in regulatory benefit-cost analysis. SCC estimates were first published in a 2010 technical support document (IWG, 2010) after the initial DEIS and Regulatory Impact Analysis for the Colorado Roadless Rule, including a temporary road construction exemption for the North Fork Coal Mining Area, was published in July 2008 but before release of the revised DEIS in April 2011.

The SCC is a metric that estimates the monetary value of future worldwide impacts associated with marginal changes in carbon dioxide emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. The IWG SCC estimates were developed to promote consistency in the SCC values used by federal agencies to assess the benefits of rulemakings that have an incremental impact on cumulative global carbon dioxide emissions. The *Social Cost of Greenhouse Gas Emissions* section below provides more discussion on the development of the IWG estimates. Social costs of methane emissions (SCM) have been developed and published in a manner similar to SCC; SCM values have been incorporated into this analysis as outlined in the *Discounted Benefits, Social Costs, and Present Net Values Incorporating Social Cost of Carbon (from Carbon Dioxide and Methane)* section.

In order to assess ‘net cumulative’ emissions, it is necessary to consider how production and consumption of coal and natural gas in other supply and electricity demand regions outside of the larger North Fork area (or the ‘Colorado – Uinta’ supply region) will change (i.e., decrease) in response to changes in production of North Fork Coal Mining Area coal. Accounting for these market substitution effects will provide a more reliable estimate of net cumulative changes in GHG emissions from overall production and consumption of energy beyond the boundary of the GMUG National Forests (and the North Fork Coal Mining Area). The IWG SCC values reflect damages to global populations, not just the U.S. public, implying an additional atypical expansion or dimension to traditional benefit and cost analysis for Forest Service actions.

The steps for conducting the benefit-cost analysis to estimate the ranges of PNVs for increasing North Fork coal resources under Alternatives B and C, relative to Alternative A, are summarized in the following steps:

1 - Gross Changes in North Fork Coal Mining Area Production: Project changes (i.e., increases) in annual coal production from the North Fork Mining Area, by year, over a period of years necessary to exhaust available North Fork coal resources.

- The maximum period of time estimated to exhaust North Fork coal resources is estimated to be 2015 to 2054 (see *Net Energy Production, Consumption, and Exports – Accounting for Market Substitution* section and Appendix C of the SFEIS for details).
- Schedules of annual coal production are estimated under three production rate assumptions: Low, Average, and Permitted (maximum) (see *Existing Conditions and Gross North Fork Coal Production* section).

2 - Net Changes in Domestic (National) Coal and Gas Production: Project net change in annual national production of (i) underground-mined coal, (ii) surface-mined coal, and (iii) natural gas, resulting from increased production of North Fork coal and accounting energy market substitution. Projected net changes are calculated by multiplying projected annual North Fork Coal Mining Area production for each year from 2016 to 2054 (from Step 1) by 'substitution response factors' (e.g., change in tons of surface coal produced nationally per ton increase in North Fork production).

- 'Substitution response factors' are estimated for Alternatives B and C by calculating:

$$= \frac{\mathit{Total\ change\ in\ National\ coal\ or\ gas\ production}\ (2016-2054)}{\mathit{Total\ change\ in\ North\ Fork\ Coal\ Mining\ Area\ coal\ production}\ (2016-2054)}$$

- Changes in national production are modeled using the IPM framework and changes in North Fork Coal Mining Area coal production are estimated in Step 1. See the *Net Energy Production, Consumption, and Exports – Accounting for Market Substitution* section for details. See SFEIS, Appendix C (Response coefficients and other factor assumptions for 'Reserves Added' scenario (IPM v5.13); Table C-22) for examples of substitution response factors and an application of using response factors to calculate decreases in substitute fuel production, in response to increases in North Fork Coal Mining Area production.
- Net decreases in renewable fuel production are also modeled, but substitution response factors are not necessary because GHG emissions from renewable fuel production and use are conservatively assumed to be zero. As a consequence, any portion of gross increases in GHG emissions from North Fork Coal Mining Area coal production that substitute for renewable energy (i.e., result in a decrease in renewable energy production) are therefore assumed to be net or cumulative increases in GHG emissions for the purposes of calculating GHG damages.
- Increases in North Fork Coal Mining Area coal production are estimated to result in decreases in national surface coal and natural gas production, due to market substitution, as modeled using the IPM framework. As a consequence, substitution response factors for surface coal and natural gas are negative. Substitution response factors for underground coal production are positive, reflecting increases in North Fork Coal Mining Area production under Alternatives B and C.
- Substitution response factors are assumed to be the same for Low, Average, and Permitted North Fork Coal Mining Area production scenarios.

3 - Net Changes in Domestic (National) Electricity Production from Coal and Gas: Project net changes in annual national electricity generation from combustion of (i) underground and surface coal combined and (ii) natural gas, resulting from electricity market responses to increased supply of North Fork Coal Mining Area coal. Projected net changes are calculated by multiplying projected annual North Fork Coal Mining Area production for each year from 2016 to 2054 (from Step 1) by 'substitution response factors' (e.g., change in GWh (gigawatt hour) electricity from coal (or gas) per ton increase in North Fork Coal Mining Area production). See SFEIS, Appendix C (Response coefficients and other factor assumptions for 'Reserves Added' scenario (IPM v5.13); Table C-22) for

examples of substitution response factors and an application of using response factors to calculate decreases in electricity generation from substitute fuel sources, in response to increases in North Fork Coal Mining Area production. This analysis projects changes in the mixture of fuels types used to generate electricity, not changes in total electricity generation across all fuel sources. Total electricity generation across all fuel sources, by year, is assumed to remain the same across alternatives,

‘Substitution response factors’ are estimated for Alternatives B and C by calculating:

$$= \frac{Total\ change\ in\ National\ Electricity\ (GWh)\ from\ coal\ (or\ gas)\ (2016 - 2054)}{Total\ change\ in\ North\ Fork\ Coal\ Mining\ Area\ coal\ production\ (2016 - 2054)}$$

Changes in national electricity generation from coal and gas are modeled using the IPM framework and changes in North Fork Coal Mining Area coal production are estimated in Step 1. See the *Net Energy Production, Consumption, and Exports – Accounting for Market Substitution* section for details.

Net decreases in electricity from renewable fuel are also modeled, but substitution response factors are not necessary because GHG emissions from use of renewable fuel are conservatively assumed to be zero. As a consequence, any portions of gross increases in GHG emissions from increases in electricity generation from added North Fork coal that substitute for electricity generated from renewable energy (i.e., result in a decrease in electricity generated from renewable energy) are therefore assumed to be net or cumulative increases in GHG emissions for the purposes of calculating GHG damages.

Increases in North Fork coal production are estimated to result in decreases in national electricity generation from gas, due to market substitution, as modeled using the IPM framework. As a consequence, the substitution response factors for natural gas is negative. The substitution response factor for coal is positive, reflecting increases in availability of North Fork Coal Mining Area coal to electricity sector under Alternatives B and C. Substitution response factors are assumed to be the same for Low, Average, and Permitted North Fork Coal Mining Area production scenarios.

<u>4 - Net Changes in Coal Exports: </u>Project net change in annual national coal exported. Projected net changes are calculated by multiply projected annual North Fork Coal Mining Area production for each year from 2016 to 2054 (from Step 1) by ‘substitution response factors’ (e.g., change in tons coal exported per ton increase in North Fork Coal Mining Area production).

The calculation procedures in Steps 2 and 3 are also applied for changes in coal exports. Substitution response factors are positive. ‘Substitution response factors’ are estimated for Alternatives B and C by calculating:

$$= \frac{Total\ change\ in\ Coal\ Exports\ (tons) from\ IPM\ output\ (2016 - 2054)}{Total\ change\ in\ North\ Fork\ Coal\ Mining\ Area\ coal\ production\ (2016 - 2054)}$$

<u>5 - Net Changes in Domestic Carbon Dioxide and Methane Emissions from Coal and Gas Production and Consumption</u>: Estimate net changes in carbon dioxide emissions by multiplying carbon dioxide emission factors for production, consumption, and coal transportation by annual net coal and gas production and consumption from Steps 2 and 3, for each year from 2016 to 2054. Examples of emission factors, as well as carbon dioxide emission calculations using emission factors are provided in Table C-22 in Appendix C of the SFEIS.

Coal transportation emission coefficients are estimated based on an 1,800 mile roundtrip (900 mile one-way) distance domestically, and a 10,000 roundtrip (5,000 mile one-way) for exported coal. Domestic distance is derived from projected locations of coal consumed, as

> modeled using the IPM framework. Exported coal is assumed to be consumed for electricity generation using the same emission factor as used for domestic coal consumption.

Methods for estimating methane emissions are similar to methods for carbon dioxide and are based on net changes in underground and surface coal production, as well as net changes in natural gas production. Transportation is accounted for as part of coal and gas production as described in the *Air Resources and Greenhouse Gas Emissions* section. Changes in methane emissions associated with net changes in coal and natural gas production and transportation are accounted for in net methane emission calculations; however, not the combustion of coal and natural gas, nor the transportation of exported coal.

6 – Global Social Costs of Net Changes in Carbon Dioxide Emissions: Estimate social costs of annual net changes in carbon dioxide emissions by multiplying aggregated net carbon dioxide emissions by SCC values, by year (recalling that real SCC values increase with time). Similar process accounting for the net changes in methane emissions is also carried out using SCM values (IWG, 2016b). For details about SCC values, see the *Social Cost of Greenhouse Gas Emissions* section below.

> The benefit-cost analysis focuses on the Global Boundary to the global nature of climate change (see SFEIS, *Response to Comments* in Appendix E for details). SCC and SCM values as presented by the IWG Technical Support Document are considered, resulting in a range of social costs, for each of the three North Fork Coal Mining Area production scenarios. See the *Social Costs of Greenhouse Gas Emissions* section for details.

7 – Domestic Benefits of Electricity Generation: Annual domestic benefits are assumed equal to annual domestic power generation cost savings. Annual cost savings are calculated by multiplying annual gross changes in North Fork Coal Mining Area coal production by ‘cost saving response factors’ (e.g., change in national electricity generation cost per ton increase in North Fork Coal Mining Area production). Response factors are derived from IPM modeling results as detailed in the *Benefits of Coal Resources* section.

> Global benefits from increases in consumer surplus for non-U.S. populations, associated with consumption of increased U.S. coal exports resulting from availability of North Fork Coal Mining Area coal resources could not be estimated and are therefore assumed to be zero under the Global accounting stance. Domestic (U.S.) benefits from electricity cost savings are retained under the Global accounting stance (as described in *Benefit and Social Cost Accounting Stances* section).

8 – Discounted Benefits, Social Costs, and Present Net Values: OMB Circular A-4 for Regulatory Impact Analysis directs analysts to use discount rates of 3% and 7%. However, to remain consistent with discount rates used to derive ranges of SCC and SCM values (IWG, 2015), annual social costs and benefits from steps 6 and 7 above were discounted at rates consistent with rates assumed for SCC and SCM values (i.e., 2.5%, 3%, and 5%). SCC and SCM values based on a 7% discount rate are not used within the IWG technical direction. The values used for the SCC and SCM analyses were the Average Scenario for 2.5% rate, the Average Scenario for 3% rate, the 95th percentile for 3% rate, and the Average Scenario for 5% rate. The *Social Costs of Greenhouse Gas Emissions* section includes a description of these values presented in this analysis. Some benefit-cost results from the SDEIS incorporated the use of 10th percentile values for the 3% rate for the SCC analysis. Those have been carried over into this document only for disclosure purposes to demonstrate changes between the SDEIS and the SFEIS. The 10th percentile applies only to IPM® v5.13-based results in the SDEIS, and 10th percentile values only affected the upper estimates of SDEIS PNV under the global stance (see SFEIS, Appendix C for details). All results in the SFEIS rely on IPM v5.15 and do not consider the 10th percentile values to maintain consistency with the TSD and its application by other federal agencies.

Discounted costs and benefits are summed for 2016 to 2054 to estimate PNVs for different combinations of North Fork Coal Mining Area production scenarios and SCC and SCM values, thereby generating a range of PNV results for each Alternative. Details about these steps are provided in sections below, as well as in Appendix C of the SFEIS, which includes a discussion about the uncertainty and sensitivity associated with some of the key assumptions.

Benefit and Social Cost Boundary Stances

This analysis focuses on the global boundary stance for evaluating costs and benefits due to the global nature of climate change. This analysis also models net changes in national coal and natural gas production as well as consumption (for electric power generation) to account for market substitution responses to increases in Colorado-Uinta coal production.

- Benefits are represented by (i) domestic power generation cost savings resulting from increased North Fork Coal Mining Area coal resources (accounting for substitution), and (ii) the net value of coal exports resulting from North Fork Coal Mining Area production (accounting for domestic substitution, but not foreign substitution). No effort was made to capture the benefits of potential power generating efficiency gains in foreign countries.
- Social costs are calculated by applying SCC values to carbon dioxide emissions from (i) net coal and natural gas production, coal transportation, and domestic coal and natural gas consumption (accounting for substitution), and (ii) coal exported, including overseas transport and consumption for electric power (accounting for domestic substitution but not foreign substitution effects). The benefits of coal consumption include electricity generated as a result of that consumption; however, for this analysis, the amount of electricity generated is assumed to remain constant across alternatives (see discussion of IPM modeling framework in Appendix C of the SFEIS). Changes in electricity generation are therefore not used to characterize benefits; instead, reductions in cost to achieve fixed levels of electricity demand are the basis for describing benefits.

Net Energy Production, Consumption, and Exports—Accounting for Market Substitution

Changes in gross production and consumption of coal from the North Fork Coal Mining Area are expected to have an effect on production and consumption of other fuel sources, including alternative supplies of coal, natural gas, and other energy supplies such as renewables, especially in later years of the analysis. As a consequence, this final CRR RIA attempts to characterize market responses and substitution effects in order to estimate net changes in energy production and consumption. Net changes will provide a more reliable basis for estimating cumulative net GHG emissions, and subsequent social costs.

This supplemental analysis for the final rule RIA uses the IPM of U.S. energy supply and power generation (IPM, 2015; ICF, 2015a; see SFEIS, Appendix C) to predict how production and consumption of other sources of coal and natural gas, as well as alternative sources of energy (e.g., renewables, bio/waste fuel) respond to, substitute, or offset for changes in the supply of low sulfur bituminous coal from the North Fork Coal Mining Area. The IPM model predicts the mixture of non-renewable fuels (e.g., bituminous coal, subbituminous coal, other coal, natural gas, petroleum-based) and alternative fuels (e.g., renewables, nuclear, biomass, landfill gas) that will minimize the cost of achieving a given or pre-established schedule of annual power (e.g., electricity) demand over time (this analysis looks at the period 2016 to 2054). The IPM model is used to project the least-cost mixture of fuel types, by supply region and/or State, to meet a given amount of power demand. Based on data regarding fraction of coal coming from underground versus surface mines, by coal supply sub-region (MSHA, 2015; ICF, 2015b) it is possible to extrapolate percentage of coal production that comes from underground and surface mines (thereby providing the basis to estimate GHG emissions, by mine type). IPM uses dynamic linear programming to model how electricity demand is met through a mix of generation and transmission in each region, as well as transmission between regions. The North American version of IPM includes international coal demand and coal supply regions to forecast global coal production and movement (i.e., IPM models domestic production and consumption of coal, as well as coal imports and exports). IPM relies on sets of coal and other forms of energy supply (e.g., natural gas) curves, for specific types of energy and specific supply sub-regions.

The IPM framework is used to establish a baseline mixture of fuel supplies that satisfy demand, based on EPA's v5.13 base case along with other modifications made by USFS to EPA's Base Case and summarized in the SFEIS Appendix C; the base case conditions are assumed to reflect the baseline mixture of fuels under Alternative A (i.e., without increasing the availability of North Fork Coal Mining Area coal resources). EPA uses IPM to analyze the impact of air emission policy on the U.S. electric power sector. As part of those analyses, EPA publishes its assumptions and other information regarding its use of IPM. This supplemental analysis uses EPA's coal supply curves from EPA's v5.13 IPM base case, which is documented on EPA's website (EPA, 2015f) with some adjustments and augmentations (ICF, 2015a; SFEIS, Appendix C) to represent baseline coal/energy production and consumption for the Nation under Alternative A. The Forest Service adopts IPM 5.13 and 5.15 nomenclature because of these similarities for ease of reference. However, use of this nomenclature is not meant to indicate that the Forest Service has used IPM in the exact manner as EPA.

The IPM baseline conditions can be modified to simulate the effects of increasing North Fork Coal Mining Area coal resources under Alternatives B and C. The IPM framework relies on a set of energy supply curves that describe how much of each energy type is available and at what cost, for different supply sub-basins around the country. Within the Colorado-Uinta supply region, there is a supply curve for low-sulfur bituminous coal which includes the available coal resources for the individual coal mines within the North Fork Valley, as well as expected supply or mining costs for those mines.

To simulate the effects of Alternative B, the available coal resources for the North Fork Coal Mining Area were increased, allowing the IPM framework to re-calculate the least cost mixture of fuels needed to generate the given (fixed) amount of power demand. The results indicate that overall electricity generation remains the same, relative to baseline conditions, as expected given that the IPM framework assumes no change in demand. However, the mixture of fuels shifts, including increases in production and consumption of underground coal, and decreases in production and consumption of substitute fuel sources such as surface coal, natural gas, and renewable energy. As a consequence, added electrical generation from North Fork Coal Mining Area underground coal sources is offset by reductions in electrical generation by substitute fuel sources under Alternative B (and C).

IPM modeling results also provide estimates of aggregate costs of electricity production; electricity generation costs are lower under Alternative B, compared to A, as expected, given the increased availability (and flexibility) of fuels that electricity generators can select from to minimize costs. These cost savings, or cost reductions, are the basis for estimating benefits under Alternative B, compared to A.

To predict substitution responses associated with increased North Fork Coal Mining Area coal production under Alternative B (and C), the available coal resources for the supply curve that includes the relevant mines currently operating within the study area is increased by 172 million short tons. This IPM modeling scenario is referred to as the "add reserves" scenario. Details about this, as well as other IPM modeling scenarios are provided in Appendix C of the SFEIS.

IPM output demonstrates how production and consumption of other coal supplies, as well as natural gas and renewable energy supplies change in response to increases in North Fork Coal Mining Area coal resources under Alternative B. IMP results indicate that the added 172 million short tons of coal resources are exhausted by 2054. IPM results are used to estimate aggregate change in production (or consumption) of alternative energy sources from 2016 to 2054 as well as aggregate change in Colorado-Uinta basin coal production over the same period as described above. Changes in Colorado-Uinta basin coal production are assumed to represent changes in North Fork Coal Mining Area coal production (since the only change made to the model was a change in coal resources for North Fork Coal Mining Area coal).

IPM modeling results used to calculate 'substitution' response factors for energy production are calculated by dividing aggregate changes in national underground coal, surface coal, and natural gas production by aggregate change in Colorado-Uinta basin production (e.g., +0.5 million tons in total national underground coal production/million tons of Colorado-Uinta basin coal production; -0.5 million tons of total national surface coal production/million tons of Colorado-Uinta coal production).

Response factors are negative for surface coal and natural gas because these are substitutes, in part, for underground coal. As the availability of underground coal increases (under Alternative B), electricity generators are expected to respond by consuming greater amounts of underground coal and reduced amounts of substitute sources of energy.

Substitution response factors for energy consumption (i.e., power generation) are calculated in a similar manner by dividing aggregate changes in national power generation from coal and natural gas by aggregate change in Colorado-Uinta basin coal production (e.g., 500 GWh from coal combustion/million tons of Colorado-Uinta basin coal production). Substitution response factors are multiplied by projected changes in gross North Fork Coal Mining Area coal production to estimate net national changes in coal and natural gas production and consumption, in preparation for estimating changes in carbon dioxide emissions.

Net Cumulative Carbon Dioxide Emissions

Net cumulative carbon dioxide emissions are estimated by multiplying carbon dioxide emission factors by estimates of net coal and natural gas production and consumption levels for each year, production schedule, and alternative. The carbon dioxide emission factors for production (e.g., metric tons carbon dioxide /short ton underground coal produced; metric tons carbon dioxide /billion cubic feet gas) and for consumption (e.g., metric tons carbon dioxide /GWh generated from coal; metric tons of carbon dioxide /GWh generated from gas) were obtained from the same sources as those used to estimate emissions in the *Air Resources* section in the SFEIS.

Benefits of Coal Resources

Domestic power generation cost savings for the Global Boundary stance is estimated by calculating aggregate cost for generating electricity from all sources (including transportation and transmission costs) for the Nation from 2016 to 2054 for the IPM v5.13 base case and 'add reserves' scenario. The *Net Energy Production, Consumption, and Exports – Accounting for Market Substitution* section and Appendix C of the SFEIS provide details about IPM modeling scenarios. Given that substitution and market response modeling under the IPM framework assumes electricity demand is fixed at pre-established levels, benefits from increases in electricity generation resulting from increased availability of coal resources cannot be calculated. Benefits are therefore based on estimated reductions in costs of meeting fixed electricity demand. Benefits are therefore based on changes in cost (i.e., cost savings) associated with shifts in mixtures of fuels used to generate electricity, while social costs are based on changes in the social cost of carbon (from carbon dioxide emissions) associated with those same shifts in mixtures of fuels.

The difference in aggregate costs for these scenarios is assumed to be aggregate cost savings resulting from the additional North Fork Coal Mining Area coal resources. Total aggregate cost savings are divided by total aggregate change in Colorado-Uinta basin coal production (also from the difference in the IPM base case and 'add reserves' scenarios) to obtain a cost savings response factor. Response factors are multiplied by annual differences in North Fork Coal Mining Area coal production between Alternatives B and A (and Alternatives C and A) to estimate costs savings for each year of North Fork Coal Mining Area production for Alternatives B and C, relative to Alternative A, for each of the three production scenarios. Due to the nature of these calculations, benefits based on domestic power generation cost savings are estimated only for differences between alternatives, not individual alternatives.

Social Costs of Greenhouse Gas Emissions

This analysis demonstrates the application of SCC values to smaller-scale GHG emissions from potential expansion of coal production from the North Fork Coal Mining Area coal leases that could be the indirect result of this rulemaking: reinstating an exception that could allow for temporary road construction that could enable future expansion of coal mine operations.

The SCC and SCM estimates applied in this analysis reflect the worldwide damages from climate change. Current guidance contained in OMB Circular A-4 indicates that analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the IWG (including OMB) determined that a modified approach is more appropriate in this case because the climate change problem is highly unusual in a number of respects. Anthropogenic climate change involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States, and conversely, greenhouse gases emitted elsewhere contribute to damages in the United States. Consequently, to address the global nature of the problem, estimates of the social cost of greenhouse gases must incorporate the full (global) damages caused by emissions. In addition, climate change presents a problem that the United States alone cannot solve. Other countries will also need to take action to reduce GHG emissions if significant changes in the global climate are to be avoided. Furthermore, adverse impacts on other countries can have spillover effects on the United States, particularly in the areas of national security, international trade, public health, and humanitarian concerns. Thus, the IWG concluded that a global measure of the benefits from reducing U.S. CO2, CH4 (and N2O) emissions is preferable. See IWG (2010, 2016a) for more discussion.

Social costs for this analysis are estimated using the average SCC estimates for at three discount rates (2.5%, 3%, 5.0%) as well as the 95th percentile of the frequency distribution using a 3% discount rate, presented in the current SCC technical support document, Table 3-2. SCC estimates for several discount rates are included because the literature shows that the SCC is sensitive to assumptions about the discount rate, and because consensus does not exist on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The SCC values increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change and because GDP is growing over time and many damage categories are modeled as proportional to GDP. Note that the growth rate of the SCC is estimated directly within the three integrated assessment models rather than assuming a constant annual growth rate. This helps to ensure that the estimates are internally consistent with other modeling assumptions.

Table 3-2. *Social cost of carbon dioxide (SCC), 2010–2050 (2007$/metric ton CO_2)*

Year	*Discount Rate* 5.0%	3.0%	2.5%	High Impact
	Average			*95th Percentile at 3%*
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

Source: IWG, 2015.

In order to estimate the dollar value of emissions impacts, the SCC estimate for each emissions year was applied to changes in carbon dioxide emissions for that year, and then discounted back to the analysis year using the same discount rate used to estimate the SCC. An analogous approach was used to monetize the climate impact associated with the SCM emissions changes. See the *Air Resources and Greenhouse Gas Emissions* section for discussions on other non-CO_2 emission.

The 2010 SCC Technical Support Document noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. Another source of uncertainty are gaps in the ability of current SCC estimates to account for the ripple or compounding effects that projected damages to some goods and services may have on indirect production of other goods and services, or the overall productivity of global economies. These individual limitations do not all work in the same direction in terms of their influence on the SCC estimates, though taken together they suggest that the SCC estimates are likely conservative. The Intergovernmental Panel on Climate Change, Fourth Assessment Report (IPCC, 2007) concluded that “It is very likely that [SCC estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts.”

The current SCC (IWG, 2016a) estimates and the discussion of their limitations currently represents the best available compilation of information about the social benefits of carbon dioxide reductions to inform regulatory impact analysis for actions that directly affect or change cumulative global GHG emissions. This SEIS demonstrates the application of these SCC estimates to smaller-scale land management decisions that indirectly affect GHG emissions. The new versions of the models used to estimate the values for this supplemental analysis offer some improvements in these areas, although work in this area is ongoing. EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates. Additional details are provided in Appendix C of the SFEIS.

The social costs of climate change presented in this supplemental analysis are associated with changes in carbon dioxide and methane emissions. If coal leases were processed and mining did take place in the future, it could also have an impact on the emissions of other pollutants that affect the climate. The *Air Resources* section includes potential emissions of methane and nitrous oxide. The social costs of methane emissions have been included in the PNV estimate using a protocol from the updated Technical Support Document from the IWG.

The social costs of CO_2 emissions from action alternatives are estimated using the SCC values presented in the most current SCC Technical Support Document (IWG, 2016a) and Addendum on non-CO2 GHGs (IWG, 2016b). The SCC Technical Support Document and Addendum provide SCC and values through 2050. Given that the analysis period for monetizing benefits and costs extends to 2054, SCC values for the years 2051 to 2054 are extrapolated using the percent change in SCC and SCM values from 2049 to 2050.

Non-Monetized Social Costs

Other benefits and costs are not monetized in this analysis. Due to current data and modeling limitations, estimates of the costs from CO_2 emissions do not include impacts like ocean acidification or potential tipping points in natural or managed ecosystems. Unquantified costs may also include climate effects from emissions of GHGs other than carbon dioxide and methane and ancillary impacts from carbon emission on ecosystem (see SFEIS, *Climate Change* section).

Damages associated with GHGs other than carbon dioxide and methane and damages to other goods and services that may not be directly addressed in the same methods used to derive SCC estimates are discussed qualitatively.

Whether the estimated economic impacts or benefits and costs of each alternative actually occur depends on many variables, some within the Forest Service control, such as approval of surface activities during leasing activities, and many outside Forest Service control, such as the future of coal prices, continued environmental regulatory trends, or natural gas prices. Such uncertainties are why it is difficult to predict the potential impacts of a programmatic plan. The following section estimates the economic effects to serve as a comparison between alternatives and a reasonable portrayal of the potential impacts.

Benefits, Social Costs, Substitution, and Present Net Value Results

Results from the SDEIS, based on IPM v5.13 and accounting only for CO_2 social costs, are repeated in this section and then compared to new results based on IPM v5.15 and accounting for a combination of CO_2 and methane social costs. These comparisons demonstrate how results have changed from the SFEIS.

Net Energy Production, Consumption, Exports, and Carbon Dioxide Emissions

Changes in net energy production and consumption, as well as carbon dioxide emissions associated with production and consumption that occurs between 2016 and 2054 (see Table 3-1) under IPM® v5.13, is summarized in Table 3-3. These results demonstrate the substitution that could occur across supply and demand regions in response to increased production of coal within the North Fork Coal Mining Area under alternatives B and C using IPM v.5. 13. The Forest Service used IPM v5.13 to model the proposed Clean Power Plan by adopting prices on CO_2 in order to proxy the proposed regulation that covers CO_2 emissions (ICF 2015a).[3]

[3] The United States is currently defending the legality of the Clean Power Plan. *West Virginia v. Environmental Protection Agency*, No. 15-1363 (D.C. Cir.). On February 9, 2016, the U.S. Supreme Court stayed the Clean Power Plan pending judicial review before the D.C. Circuit Court of Appeals and any subsequent proceedings in the Supreme Court.

Table 3-3. *Changes in the mixture of energy production, electricity generation, and CO_2 emissions for Alternatives B and C, compared to Alternative A (totals for 2016–2054) under IPM® v5.13 (SDEIS results)*

	Alternatives	
	B-A	*C-A*
Change in Gross North Fork Coal Production (1)		
Total Coal Production – million short tons	172	95
Change in Net Domestic Energy Production (2)		
National Underground Coal – million short tons	91	50
National Surface Coal (million short tons)	-23	-13
Total National Coal (million short tons)	68	37
National Natural Gas (billion cubic feet)	-271	-149
Change in Net Domestic Electricity Generation by Fuel Type (3)		
Electricity from Coal (GWh)	112,168	61,585
Electricity from Natural Gas (GWh)	-71,677	-39,354
Electricity from Renewable Energy (GWh)	≈-40,000	≈-22,000
Total Electricity Generation (GWh)	≈0	≈0
Change in Coal Exports (shipped and consumed) (4)		
Coal Exports (million short tons)	17	9
Change in Net CO_2 Emissions (Million metric tons)		
From Production of Coal and Natural Gas	1.1	0.6
From Domestic Consumption of Coal	118	65
From Domestic Consumption of Gas	-43	-24
From Domestic Consumption of Coal and Gas	75	41
From Transportation of Coal	10	5
From Exported Coal Transport plus Combustion	45	25
Total CO_2 Emissions	131	72

(1) Based on schedules of North Fork Production, by Alternative (see Table 3-1).
(2) Net energy production reflects decreases in production of substitute sources of fuel, including sources of underground coal from other supply regions, in response to increases in North Fork underground coal production.
(3) Changes in aggregate electricity generation across energy sources are assumed to be zero, reflecting IPM modeling assumptions of fixed demand across alternatives.
(4) Changes in net carbon dioxide emissions in this table are used to estimate social costs of carbon dioxide emissions for the global accounting stance in Table 3-6 (see the "*Overview of Benefit-Cost Framework* section" for calculation steps).

The assumption that total gross production of underground coal from the North Fork Coal Mining Area increases by 172 million short tons from 2016 to 2054 for Alternative B, compared to Alternative A, is shown in Table 3-3. Production from other substitute sources of underground coal around the Nation are likely to decrease, in many cases, in response to this increases in North Fork Coal Mining Area underground coal production. These decreases offset, in part, some of the 172 million short tons of underground coal production from the North Fork Coal Mining Area, resulting in net domestic underground coal production of 91 million short tons. These results are estimated using response coefficients derived from IPM modeling results; see the *Overview of Benefit-Cost Framework* section.

Similarly, production of substitute sources of surface coal and natural gas across the country are estimated to decrease by 23 million short tons and 271 billion cubic feet respectively, in response to increases in North Fork Coal Mining Area coal production. Total electricity generation is assumed to remain constant across alternatives, so change in total electricity generation is equal to zero for Alternative B, compared to A. However, the mix of energy sources used to generate the electricity changes, in response to increases in North Fork Coal Mining Area coal production. Electricity generated from coal (underground and surface mined) is estimated to increase by about 112,000 GWh, while electricity generation from natural gas decreases by about 72,000 GWh. Decreases in electricity generation from renewable energy sources makes up the remaining balance of about 40,000 GWh. Electricity generation from renewables decreased by a total of 41,000 GWh under v5.13, as a result of adding North Fork coal mining area supplies. Under v5.15, electricity generation from renewables decreased by 12,000 GWh (i.e., North Fork coal mining area had less impact on renewables under v5.15.

These shifts in the mixtures of energy used to generate electricity, as well as the production of different types of energy will change carbon dioxide emissions. Total carbon dioxide emissions increase by 131 million metric tons under Alternative B, compared to A (Table 3-3). Changes in carbon dioxide emissions are estimated by multiplying changes in net energy production, net electricity generation, and coal exports by respective carbon dioxide emission factors, as explained in benefit-cost steps outlined in the *Overview of Benefit-Cost Framework* section. More details are provided in Appendix C of the SFEIS.

Net Energy Production, Consumption, Exports, and Carbon Dioxide Emissions Modeled under Final Colorado Roadless Rule with IPM® v5.15

In the newer IPM v5.15 that the Forest Service is using for this analysis, a number of changes have been made from the analysis for the proposed North Fork coal mining area exception, including:

- Accounting for implementation of the final Clean Power Plan (40 CFR Part 60) rather than relying on a carbon price proxy to account for the proposed Clean Power Plan.
- Electricity demand has been revised downward, consistent with more recent Energy Information Administration, Annual Energy Outlook forecasts. This revision has implications for projections and future demand for electricity among competing sources.
- Natural gas supply assumptions have been updated, such that gas prices are lower than the v5.13.
- Coal supply adjustments have also been made, leading to lower prices overall.
- Coal transportation assumptions in v.5.13 reflect a much higher diesel outlook rather than the price forecast expected today.

Some of these factors are reflected in the different base case modeling assumptions USFS adopted from USEPA's IPM modeling for the final and proposed exemption rule (i.e., EPA Base Case v5.13 and v5.15). See SFEIS, Appendix C for detailed descriptions of changes in Base Case modeling assumptions under IPM v5.15. Overall, these factors affect the competitiveness of coal-fired power generation in the domestic marketplace, consequently influencing the projected market substitution of coal production resulting from the proposed action. Because the carbon price proxy under IPM® v5.13 was based on the proposed Clean Power Plan rule and not the final rule, the preceding analysis (shown in Table 3-3) is updated using v5.15 IPM Base Case that also accounts for the final Clean Power Plan. Changes in net energy production, consumption, and CO_2 emissions under IPM® v5.15 are summarized in Table 3-4.

Table 3-4. *Changes in the mixture of energy production, electricity generation, and CO2 emissions for Alternatives B and C, compared to Alternative A (totals for 2016–2054) under IPM® v5.15 (SFEIS results)*

	Alternatives	
	B-A	*C-A*
Change in Gross North Fork Coal Production (1)		
Total Coal Production – million short tons	172	95
Change in Net Domestic Energy Production (2)		
National Underground Coal – million short tons	102	56
National Surface Coal (million short tons)	-115	-63
Total National Coal (million short tons)	-13	-7
National Natural Gas (billion cubic feet)	-24	-13
Change in Net Domestic Electricity Generation by Fuel Type		
Electricity from Coal (GWh)	12,618	6,928
Electricity from Natural Gas (GWh)	-3,445	-1,892
Electricity from Renewable Energy (GWh)	≈-9,000	≈-5,000
Total Electricity Generation (GWh)	≈0	≈0
Change in Coal Exports (shipped and consumed)		
Coal Exports (millions short tons)	0.00017	0.00009
Change in Net CO_2 Emissions (Million metric tons)		
From Production of Coal and Natural Gas	1.7	0.9
From Domestic Consumption of Coal	13	7
From Domestic Consumption of Gas	-2	-1
From Domestic Consumption of Coal and Gas	11	6
From Transportation of Coal	4	2
From Exported Coal Transport plus Combustion	0.00045	0.00024
Total CO_2 Emissions	17	9

*Other than using IPM v5.15 generated response coefficients, all other assumptions are the same as those used in Table 3-3. See Table 3-3 for assumptions about these values.

Much like Table 3-3, results contained in Table 3-4 are also based on the assumption that total gross production of underground North Fork Coal Mining Area coal increases by 172 million short tons from 2016 to 2054 for Alternative B, compared to Alternative A. The differences in net domestic energy production and electricity generation transpire from the abovementioned changes in assumptions or conditions between IPM v.5.13 and v5.15—which influenced the energy market's responses to the increases in North Fork Coal Mining Area underground coal production.

Under IPM v.5.15, nationally, the available supply of substitute underground coal decreased as compared with IPM v.5.13, therefore less underground coal is available as substitute to offset portion of the 172 million short tons of North Fork Coal Mining Area coal. With fewer supplies of substitute coal, the change in net domestic underground coal production under Alternative B therefore increases slightly from 91 million short tons under IPM v5.13, to 102 million short tons of underground coal under IPM v5.15. However, total coal production (i.e., domestic underground and surface coal) decreases slightly by 13 million short tons for Alternative B under IPM v5.15, compared to an increase of 68 million short tons under IPM v5.13. This is due, in large part, to substantially greater substitution between underground and surface coal production under IPM v5.15. Surface coal production decreases by 115 million tons under IPM v5.15 but decreases by only 23 million short tons under IPM v5.13, in response to expansion of North Fork Coal Mining Area supplies. Under v5.15, there exists much greater substitution between surface and underground coal production but less between coal and natural gas. Substitution between underground coal and natural gas production is comparatively minor, due to the lower natural gas prices and greater supply available; coal is therefore less competitive as a substitute for natural gas under IPM v5.13.

Similar to coal production, electricity generation from coal increases by only 12,618 GWh under IPM v5.15, 90 percent less than an increase of 112,168 GWh under IPM v5.13. Changes in electricity production from natural gas, as well as renewable energy are also smaller under IPM v5.15, demonstrating reduced substitution between coal and those sources of energy under revised market and regulatory conditions represented by IPM v5.15.

Total net coal production and consumption are substantially less responsive to changes in North Fork coal resources under v5.15's response coefficients. Again, lower natural gas prices under the modified IPM modeling assumptions (v5.15) help drive the decrease in responsiveness under the revised coefficients, as the electricity generating sector finds it more cost effective to stick with natural gas rather than shift to using newly available coal resources. Correspondingly, increases in the use of the low sulfur bituminous coal from North Fork are offset by large decreases in use of other types of coal, rather than decreases in natural gas.

Although under IPM v.5.15 there are nearly 80 million short tons of exports in 2030 and later, over the life of project, very little exports are attributed to increases in North Fork Coal Mining Area coal production—about 170 short tons and 90 short tons for Alt B-A and Alt C-A, respectively. Note that export response coefficients, used in calculation of changes in CO_2 emissions, differ from percent of coal exported—see *Overview of Benefit-Cost Framework* section and SFEIS, Appendix C for details. Increases in percentage of North Fork Coal Mining Area exports can be offset by decreases in exports of coal from other sources and regions, resulting in export response coefficients that are less than gross coal export percentages.

These shifts in the mixtures of energy production and electricity generation also affect net carbon dioxide emissions. Total carbon dioxide emissions are estimated to increase by 17 million metric tons under Alternative B, compared to A, based on IPM v5.15 (Table 3-4). In contrast, carbon dioxide emissions increased by 131 metric million tons for Alternative B under IPM v5.13.

Differences illustrated thus far refer to Alternative B, compared to Alternative A (Alt. B-A). Net changes in the mixture of energy production, electricity generation, and CO_2 emissions for Alternative C, compared to Alternative A (Alt. C-A), encounter similar or proportional shifts under IPM® v5.15.

Substitution Methane

The three alternatives could result in differences in the estimated methane emissions from future coal mining. The IPM modeling produced estimates of future changes in the mix of energy used to create electrical grid power under each of the alternatives. These results were used to estimate changes in methane emissions from the estimates of surface and subsurface coal needed to generate electricity. The model-predicted changes in net coal production above and below ground as well as changes in natural gas production were multiplied by average emissions factors obtained from the Department of Energy's Upstream Dashboard tool to estimate changes in methane emissions. The emissions factors chosen included transportation by rail (for coal) or pipeline (for natural gas). The rail round trip transport distance was assumed to be 4,000 miles for consistency with the air and GHG analysis. For natural gas, the Upstream Dashboard default transport distance of 603 miles by pipeline was chosen.

To obtain an emissions factor for methane emissions for typical surface mining operations, the Powder River profile was selected and the Upstream Dashboard default of 51 cubic feet of methane per short ton of coal was used. The methane emissions factor from the Dashboard in mass of methane per short ton of coal produced was then multiplied by the net change in surface coal mining for each year of the economic model results for all three alternatives and all three annual coal production scenarios. The methane emissions factor for subsurface coal operations (in mass of methane per ton of short coal produced) was also obtained from the Upstream Dashboard using the Illinois Number 6 coal mine as a profile and 403 cubic feet of methane per short ton of coal as an input to the dashboard. The process used to derive the estimate of methane emissions in cubic feet per ton of coal using data for underground mining operations using data from mines in the North Fork Coal Mining Area was described in the *Air Resources and Greenhouse Gas Emissions* section of the SFIES. An emissions factor for natural gas production was also obtained from the Upstream Dashboard. The emissions factor for the 2010 national average was chosen, using default dashboard parameters for production and flaring. Differences in methane emissions were converted to CO_2e using 25 for the global warming potential.

Results for alternatives B and C are shown in Table 3-5. Positive values indicate increases in methane emissions (due to net increases in production), and negative values indicate decreases in methane emissions (due to net decreases in production). Annual changes were summed for all years in the analysis period and total net emissions changes for above and below ground coal production over the period are reported in the table.

Table 3-5. *Total net change in methane emissions due to changes in surface and underground coal mining for Alternatives B and C in millions of metric tons of CO_2e*

Alternative A minus Action Alternative	Change in methane emissions due to changes in underground coal mining	Change in methane emissions due to changes in surface coal mining	Changes in methane emissions due to changes in natural gas extraction	Total net change in methane emissions
A - B	20	-3.2	-0.15	16.7
A - C	11	-1.8	-0.08	9.2

Cumulative Effects

Cumulative benefits, costs, and net benefits are first presented for CO_2 emissions only, and then methane emissions are included with CO_2 emissions in the analysis results.

Benefits of Coal Resources

Domestic power generation cost savings for the rule are estimated by calculating aggregate cost for generating electricity from all sources (including transportation and transmission costs) for the Nation from 2016 to 2054 for the IPM v5.13 base case and 'add reserves' scenario. See the Rule's Supplemental Environmental Impact Statement's *Net Energy Production, Consumption, and Exports – Accounting for Market Substitution* section and Appendix C for details about IPM modeling scenarios. Given that substitution and market response modeling under the IPM framework assumes electricity demand is fixed at pre-established levels, benefits from increases in electricity generation resulting from increased availability of coal resources cannot be calculated. Benefits are therefore based on estimated reductions in costs of meeting fixed electricity demand. Benefits are therefore based on changes in cost (i.e., cost savings) associated with shifts in mixtures of fuels used to generate electricity, while social costs are based on changes in the social cost of carbon (from carbon dioxide emissions) associated with those same shifts in mixtures of fuels.

The difference in aggregate costs for these scenarios is assumed to be aggregate cost savings resulting from the additional North Fork Coal Mining Area coal resources. Total aggregate cost savings are divided by total aggregate change in Colorado-Uinta basin coal production (also from the difference in the IPM baseline and 'add reserves' scenarios) to obtain a cost savings response factor. Response factors are multiplied by annual differences in North Fork Coal Mining Area coal production between Alternatives B and A (and Alternatives C and A) to estimate costs savings for each year of North Fork Coal Mining Area production for Alternatives B and C, relative to Alternative A, for each of the three production scenarios. Due to the nature of these calculations, benefits based on domestic power generation cost savings are estimated only for differences between alternatives, not individual alternatives.

Discounted Benefits, Social Costs, and Present Net Values for Carbon Dioxide

The ranges of benefits and social costs of alternatives evaluated in this supplemental analysis are shown in Table 3-6 for IPM version v5.13. Calculations and discounting are described under the *Benefit and Social Cost Accounting Stances* section, as well as the *Overview of Benefit-Cost Framework* sections above. In summary, discounted benefits are the domestic power generation cost savings resulting from estimated changes in the mixture of fuels used to generate electricity under Alternative B.

Discounted social cost are based on IWG's SCC values (IWG, 2016) and carbon dioxide emissions summarized in Table 3-3. Details are provided in the SFEIS, Appendix C.

Due to the use of electric power generation cost savings as a proxy for benefits, results are provided only for Alternatives B and C, relative to Alternative A (i.e., cost savings cannot be characterized for stand-alone alternatives). Ranges are shown to account for the variation across production schedules (low, average, permitted) andSCC value assumptions.

Table 3-6. *Summary of discounted benefits and social costs results (million 2014$) under IPM® v5.13 (SDEIS results)*

	*Alternative B - Alternative A**		*Alternative C - Alternative A**	
	Discounted Benefits	Discounted Social Costs	Discounted Benefits	Discounted Social Costs
Global Boundary				
Lower Estimate (a)	$1,284	-$13,751	$792	-$7,652
3% Discount Avg. (Lower) (b)	$1,284	-$4,646	$792	-$2,611
3% Discount Avg. (Upper) (b)	$2,410	-$4,034	$1,609	-$2,420
Upper Estimate (a)	$1,781	-$931	$1,310	-$596

** The sum of discounted benefits and discounted social costs may not be exactly equal to PNV results in Table 3-8 due to rounding. Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted).*

(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted) and reflect all discount rates: 2.5%, 3%, and 5%.

(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

As shown in Table 3-4, changes in the mixture of energy production, electricity generation, and CO_2 emissions under IPM® v5.15 are different than those modeled under IPM® v5.13 (Table 3-3). Correspondingly, discounted benefits and costs results under IPM® v5.15—as shown in Table 3-7—reflect those differences.

Discounted benefits and costs decreased across alternatives under IPM® v5.15 compared to v5.13. This reflects the substantial reductions in net domestic energy production, electricity generation from coal and associated CO_2 emissions under IPM® v5.15, relative to IPM v5.13 as shown and explained in Tables 3-6 and 3-7.

Discounted benefits and costs are added to estimate PNVs in Table 3-8 for IPM version v5.13.

Table 3-7. *Summary of discounted benefits and social costs results (million 2014$) under IPM® v5.15 (SFEIS results)*

	*Alternative B - Alternative A**		*Alternative C - Alternative A**	
	Discounted Benefits	Discounted Social Costs	Discounted Benefits	Discounted Social Costs
Global Boundary				
Lower Estimate (a)	$413	-$1,808	$255	-$1,006
3% Discount Avg. (Lower) (b)	$413	-$611	$255	-$343
3% Discount Avg. (Upper) (b)	$784	-$530	$522	-$318
Upper Estimate (a)	$579	-$122	$425	-$78

** The sum of discounted benefits and discounted social costs may not be exactly equal to PNV results in Table 3-9 due to rounding. Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted).*

(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted), and reflect all discount rates: 2.5%, 3%, and 5%.

(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

PNV results are primarily negative, with values as low as negative $12 billion in net damages to positive $850 million in net benefits for Alternative B, compared to A. PNV ranges from negative $6.8 billion to positive $714 million for Alternative C, relative to A. Midpoint PNV estimates range from negative $0.8 to negative $3.4 billion in net damages for alternative B and C, compared to A.

Table 3-8. *Present Net Values under IPM® v.5.13 (million 2014$) (SDEIS results)*

	*Alternative B - Alternative A**	*Alternative C - Alternative A**
	(millions of 2014 dollars)	
Global Boundary		
Lower Estimate (a)	-$12,468	-$6,861
3% Discount Avg. (Lower) (b)	-$3,363	-$1,819
3% Discount Avg. (Upper) (b)	-$1,624	-$811
Upper Estimate (a)	$850	$714

**PNV results may not be exactly equivalent to the sum of discounted benefits and costs from Table 3-6 due to rounding. Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted).*

(a)Lower and upper estimates are drawn from results from all production schedules (low, average, permitted), and reflect all discount rates: 2.5%, 3%, and 5%.

(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

Discounted benefits and costs modeled under IPM® v5.15 (Table 3-7) are also summed to estimate PNVs in Table 3-9. PNVs remain negative for results in the lower end of the range, but midpoint PNVs, as represented by average SCC values (based on 3% discount rate) now include a mix of negative and positive results under IPM v5.15. Midpoint values are entirely negative under IPM v5.13. The overall range of PNV results is narrower under IPM v5.15 due to the substantial decreases in both benefits and social costs (see Table 3-9).

Table 3-9. *Present Net Values under IPM® v.5.15 (million 2014$) (SFEIS results)*

	*Alternative B - Alternative A**	*Alternative C - Alternative A**
	(millions of 2014 dollars)	
Global Boundary		
Lower Estimate (a)	-$1,394	-$750
3% Discount Avg. (Lower) (b)	-$197	-$88
3% Discount Avg. (Upper) (b)	$253	$204
Upper Estimate (a)	$457	$347

**PNV results may not be exactly equivalent to the sum of discounted benefits and costs from Table 3-7 due to rounding. Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted).*
(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted, and reflect all discount rates: 2.5%, 3%, and 5%.
(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

Discounted Benefits, Social Costs, and Present Net Values Incorporating Social Cost of Carbon (from Carbon Dioxide and Methane Emissions)

Methane emission was considered in the SDEIS using the SCC values and CO_2e as proxy for methane emissions, as part of the sensitivity analysis (SDEIS pp. E-24 to E-25). Due to public comments and newly available information, SCM values are incorporated here in order to demonstrate the potential for incremental differences in discounted social costs and PNV results that could be attributed to methane emissions associated with coal mining.

The IWG recently issued damage estimates for two other GHGs: methane and nitrous oxide. These estimates are based on a study by Marten et al. (2015) that provided the first set of published estimates of the social cost of methane and nitrous oxide emissions that are consistent with the methodology and modeling assumptions underlying the IWG SCC estimates. The 2016 Addendum to the SCC Technical Support Document summarizes the methodology and presents the social cost estimates from Marten et al. (2015) as a way for agencies to improve analysis of actions that are projected to influence emissions of methane and nitrous oxide in a manner that is consistent with how CO_2 emission changes are valued (IWG, 2016b). Examples of the IWG SCM estimates used in this analysis are contained in Table 3-10 for the year 2020; social cost calculations in this analysis make use of the full schedule of SCM values, similar to SCC values. The IWG presented the estimates of the social cost of these gases with an acknowledgement of the limitations and uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts, just as the IWG committed to do for SCC.

Table 3-10. *Examples of the social cost of GHGs in 2007$/metric tons, 2020*

	Discount Rate			
Gas	*5.0% mean*	*3.0% mean*	*2.5% mean*	*3% 95^{th} percentile*
CO_2	12	42	62	123
CH_4	540	1,200	1,600	3,200
N_2O	4,700	15,000	22,000	39,000

Source: IWG, 2016b.

The net benefit results including SCM are shown as an extended evaluation here for the purposes of providing transparency and response to public comments. That is, SCC results based on IPM v5.15 response coefficients presented in Tables 3-7 and 3-9 are augmented with the estimated SCM emission changes and shown in Tables 3-11, 3-12, and 3-13, as well as 3-14 below. The method of applying the SCM estimates and calculating discounted costs of methane emission is analogous to that used in the SCC-only calculation, as explained in this SFEIS (see *Overview of Benefit Cost Framework* section). Specifically, net changes in methane emissions are estimated, accounting for substitution as explained previously for Table 3-5, and multiplied by IWG SCM values for each year (U.S. Forest Service, 2016a).

Table 3-11. *Discounted social costs of net carbon dioxide (CO_2) and methane (CH_4) emissions (in millions of 2014 dollars) under IPM® v5.15 (SFEIS)*

	Alternative B – Alternative A			*Alternative C – Alternative A*		
	CO_2	*CH_4*	*CO_2+CH_4*	*CO_2*	*CH_4*	*CO_2+CH_4*
Global Boundary						
Lower Estimate (a)	-$1,808	-$2,046	-$3,853	-$1,006	-$1,127	-$2,133
3% Discount Avg. (Lower) (b)	-$611	-$766	-$1,377	-$343	-$419	-$762
3% Discount Avg. (Upper) (b)	-$530	-$733	-$1,263	-$318	-$418	-$736
Upper Estimate (a)	-$122	-$251	-$373	-$78	-$157	-$235

Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted). See SFEIS, Appendix C (Economic Analysis) for list of all PNV results and the corresponding assumptions for results in this table.
(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted), and reflect all discount rates: 2.5%, 3%, and 5%.
(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

Table 3-12. *Summary of discounted benefits and social costs results (millions of 2014 dollars) under IPM® v5.15 accounting for both Social Cost of Carbon and Methane (SFEIS)*

	Alternative B – Alternative A		*Alternative C – Alternative A*	
	Discounted Benefits	Discounted Social Costs	Discounted Benefits	Discounted Social Costs
Global Boundary				
Lower Estimate (a)	$413	-$3,853	$255	-$2,133
3% Discount Avg. (Lower) (b)	$413	-$1,377	$255	-$762
3% Discount Avg. (Upper) (b)	$784	-$1,263	$522	-$736
Upper Estimate (a)	$579	-$373	$425	-$235

Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted). See SFEIS, Appendix C (Economic Analysis) for list of all PNV results and the corresponding assumptions for results in this table.
(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted), and reflect all discount rates: 2.5%, 3%, and 5%.
(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

Table 3-13. *Annualized benefits and social costs of net carbon dioxide and methane emissions (millions of 2014 dollars) under IPM® v5.15 (SFEIS)*

	Alternative B – Alternative A		*Alternative C – Alternative A*	
	Benefits	Social Costs	Benefits	Social Costs
Global Boundary				
Lower Estimate	$19	-$177	$12	-$98
3% Discount Avg. (Lower)	$19	-$63	$12	-$35

	Alternative B – Alternative A		Alternative C – Alternative A	
	Benefits	Social Costs	Benefits	Social Costs
3% Discount Avg. (Upper)	$36	-$58	$24	-$34
Upper Estimate	$35	-$23	$26	-$14

Annualized values apply over 36 year period (based on the longest period of time needed to exhaust North Fork coal mining area supplies under the 'low' production scenario. A 3% discount range is assumed, consistent with SCC and SCM values associated with these results; exception being rate of 5% for the upper estimate.

Net benefits or PNV results for Alternatives B and C, relative to Alternative A, accounting for both $CO_2$and methane, assuming IPM® v5.15 are presented in Table 3-14. When compared to PNV results from the SDEIS (i.e., not accounting for methane and assuming IPM v5.13) (see Table 3-8 of this section), revised PNV results in Table 3-14 demonstrate the following: PNV results remain negative for all lower and midpoint PNV estimates, and positive for upper estimates. Revised ranges of PNV are narrower (e.g., -$3,500 to +$206 million compared to -12,000 to +850 million, for Alternative B-A).

Table 3-14. *Present Net Value under IPM® v5.15 accounting for both Social Cost of Carbon and Methane (millions of 2014 dollars) (SFEIS)*

	Alternative B - Alternative A	Alternative C - Alternative A
Global Boundary		
Lower Estimate (a)	-$3,440	-$1,878
3% Discount Avg. (Lower) (b)	-$964	-$506
3% Discount Avg. (Upper) (b)	-$479	-$214
Upper Estimate (a)	$206	$190

Results are drawn from the full set of individual results obtained from each combination of assumptions regarding social cost values (2.5% to 5% discount rates), and coal production rates (low, average, permitted). See SFEIS, Appendix C (Economic Analysis) for list of all PNV results and the corresponding assumptions for results in this table.

(a) Lower and upper estimates are drawn from results from all production schedules (low, average, permitted), and reflect all discount rates: 2.5%, 3%, and 5%.

(b) Ranges for average SCC values for 3% discount rates are singled out as representative of mid points.

These results indicate that some changes to PNV estimates have occurred as a result of aggregate consideration of revised response coefficients based on IPM v5.15 and social cost of methane, compared to PNV results presented in the SDEIS. However, minimal differences in signs of PNV results, coupled with relatively small changes in midpoint estimates, suggests that PNV results presented in the SDEIS remain viable for summarizing the environment effects of this decision.

There exist substantial uncertainties associated with efforts to characterize net benefits that account for GHG emissions. It is important to stress that while the concept of PNV attempts to compare the benefits and costs of decision to society; the analysis presented in this SFEIS is illustrative in nature, portraying possible cumulative effects of rulemaking, based on available information and technical support. Because reinstating an exception that could allow for temporary road construction—that could enable future expansion of coal mine operations—does not directly result in costs or benefits, numerous assumptions and scenarios were necessary in order to approximate any indirect economic effects. As such, estimates under each alternative stemmed three possible production schedules and multiple series of SCC and SCM values (from different discount rates, etc.). A complete listing of benefits, costs, and PNV results for each combination or permutation of assumptions is provided in Appendix C of the SFEIS (Economic Analysis); that list includes flags indicating which sets of assumptions are the source of results in Table 3-14. Understandably, this gave rise to an expansive range of results. That range of PNV results narrows when using response coefficients derived from revised assumptions about baseline energy market and regulatory conditions as represented by IPM v5.15, compared to conditions as represented by IPM v5.13.

The comparative results presented in this SFEIS demonstrate the sensitivity of PNV results to the potential dynamics of evolving energy markets and regulatory and policy developments. These results also demonstrate how potential market responses and effects triggered by shifts in supply of specific types of coal (e.g., low sulfur bituminous coal), from individual supply regions, within specific time frames, can be difficult to project, and may deviate from expectations based on broader interpretations of market conditions and trends. Plausibly, additional PNV estimates exist by further adjusting variables, thus adding to the permutations of scenarios. Therefore, it could be misleading to draw any inferences regarding the 'likelihoods' of any given net benefit value(s) based solely on results presented above. Ultimately, calculations used—and associated benefit-cost results—in this cumulative economic analysis are not intended to be probabilistic in nature, but illustrative.

Agency Costs

Agency costs are not expected to change across the alternatives. Potential changes in agency costs associated with road construction, road maintenance, and invasive plan management and control were addressed qualitatively in the RIA for the 2012 Colorado Roadless rule. A majority of those costs were expected to be associated with potential changes in forest or vegetation treatment projects, and unlikely to change due to expectations that program budgets for those activities would remain relatively flat. Reinstatement of the North Fork coal mining exception (Alternative B), or portions thereof under Alternative C, are not expected to alter those conditions or result in changes in treatments. As a result, substantial changes in agency costs are not expected to occur as a result of this regulatory action.

Chapter 4 Distributional Effects

Study Area

The study area for the 2012 FEIS included five western slope counties in the study area: Delta, Garfield, Mesa, Montrose, and Rio Blanco. Gunnison County, while it contains coal mines potentially affected by this action, was not included in the 2012 FEIS study area for economic impacts because mine operations and employee spending occur down valley from the mines. Garfield and Rio Blanco counties are unlikely to be affected by coal operations, but were originally included because of potential effects to oil and gas activity in the FEIS. Continuation of these five counties would have facilitated comparability of economic analysis between the 2012 FEIS and this supplement. But due to public comments, Gunnison County has been added to the study area for the affected environment in the supplemental analysis. A map of the economic study area is shown in Figure 4-1.

Figure 4-1. Colorado Roadless Supplemental: Economic Study Area.

The boundaries for the supplemental evaluation of benefits and costs varies as noted in the *Methodology* section, and extend beyond the boundaries of the economic study area.

Analysis Methods and Assumptions

<u>Economic Impact Analysis Methodology</u>

Economic impact analysis is defined as “the net change in economic activity associated with an industry, event, or policy in an existing regional economy” (Watson et al., 2007). An input-output analysis is a means of examining production, supply-chain, and employment relationships within an economy, both between businesses and between businesses and final consumers. An input-output model captures all monetary market transactions of production in a given time period. IMPLAN is a proprietary input-output modeling system composed of both software and data (MIG, 2013). The system, developed by the Forest Service in the 1970s, is widely used today by academic, government, non-profit, and private researchers and practitioners because it is a reliable and reasonable portrayal of regional economies and economic impacts. IMPLAN has been used and cited in hundreds of academic publications and presentations since its inception.

By using Forest Service expenditure data, resource output data, and other economic information, IMPLAN can estimate, among other things, the jobs and income that are supported by NFS management activities. Direct employment and labor income accrue to mine employees and their families. Additional employment and income in the economy is generated by mine purchases in the local supply-chain (indirect effects) and household spending of employee earnings (induced effects). Together the direct, indirect, and induced effects compose the total economic impact to the local economy.

To estimate the potential economic impacts of activities by alternative in the North Fork Coal Mining Area, an input-output model was developed using the IMPLAN modeling system. The IMPLAN model was then customized using employment data provided by the Colorado Department of Local Affairs, State Demography Office. Model production value, employment, and labor income was further customized to capture economic conditions and interactions in the coal mining industry using a variety of sources (see SFEIS, **Error! Reference source not found.** C). The IMPLAN model includes Delta, Garfield, Mesa, Montrose, and Rio Blanco Counties. Gunnison County is not included in the IMPLAN model. Opportunities for business and household spending in Gunnison County are located in the Gunnison-Crested Butte corridor, which is more distant and difficult to reach compared with down-valley counties. Crested Butte and Gunnison are 2-hour drives from the mines, while Delta is well under an hour and Grand Junction—a major urban center—is 1.5 hours. Kebler Pass, the primary route between the mines and Crested Butte, is closed in the winter. In addition, rail lines from the mines do not pass through the Crested Butte-Gunnison corridor, but down the North Fork Valley. Thus, although the mines and some employees are physically located in Gunnison County, they are economically connected with communities in Delta, Montrose, and Mesa Counties.

As with the model developed for the 2012 FEIS, coal mines located just east of the Delta-Gunnison county line were incorporated into the final models. This customization resulted in industry interactions with sectors and households located in the five-county area. Other Gunnison County industries were not included for the reasons described earlier. This customizing included techniques identical to those used for the 2012 FEIS (U.S. Forest Service, 2010).

Production for the coal sector within the mining industry was based on average prices for 2013 reported by the Energy Information Administration (EIA, 2013), Colorado Division of Reclamation, Mining, and Safety (DRMS, 2015), and Colorado Mining Association (2014).

Affected Environment

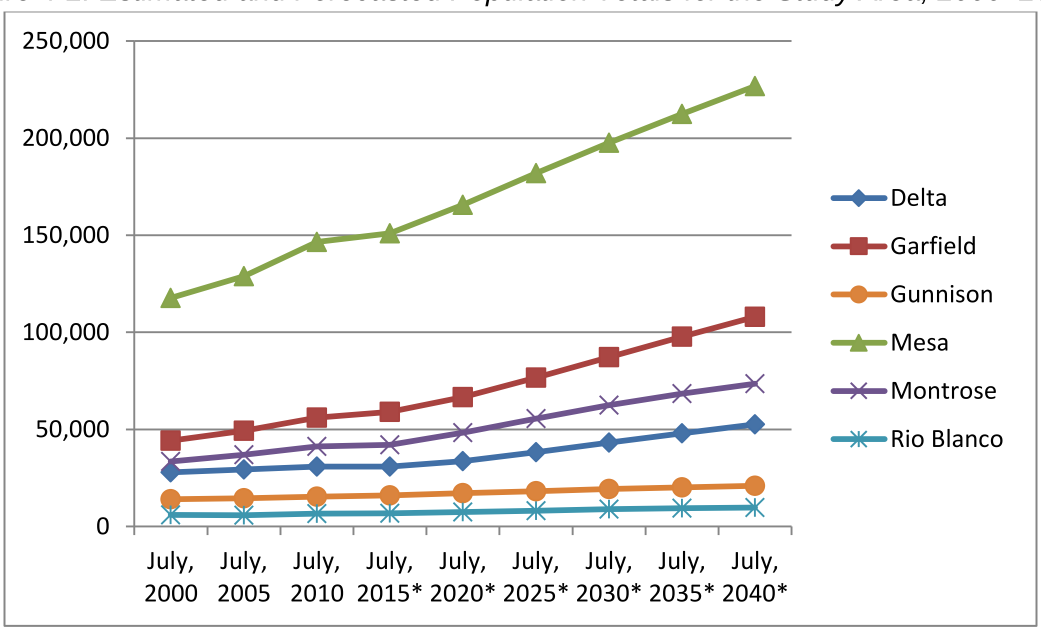
The existing economic conditions in the economic impact study area necessary to set context for comparison of alternatives and consideration of the decision are described below. The six counties included in the study area include Delta, Garfield, Gunnison, Mesa, Montrose, and Rio Blanco as the counties most likely to be directly or indirectly affected by any of the alternatives.

Population of Study Area

Long-term, steady growth of a population is generally an indication of a healthy, prosperous economy. Population growth can benefit the general population of a place, especially by providing economic opportunities. The population trends and forecasted growth of the study area produced by the Colorado Department of Local Affairs, Demography Office are shown in Figure 4-1. Population estimates (2000, 2005, and 2010) are produced annually with the most recent estimate available for the year 2013. Population forecasts (2015, 2020, 2025, 2030, 2035, and 2040) are produced annually by the Demography Office with the most recent forecasts displayed in Figure 4-2 produced in October 2014 (DOLA, 2015a).

All six counties in the study area grew between 2000 and 2010, and are forecasted to continue to grow over the next several decades. Mesa County, the largest county in the study area, continues to grow at the highest rate of the six counties. Garfield County is also forecasted to show steady increase in population in future years. Delta and Montrose Counties show similar patterns. Gunnison and Rio Blanco Counties show limited growth throughout the time period. Currently, much of the growth in the study area is from domestic migration (about 68% for the study area)—people from within the United States moving to the study area. This migration rate is much higher than the domestic rate of the State, about 51% of total state growth, indicating that the area is a place people are interested in relocating to, especially Mesa County.

Figure 4-2. Estimated and Forecasted Population Totals for the Study Area, 2000–2040.



**Years forecasted.*
Source: DOLA, 2015a.

2013 population counts for each of the study area counties from the Colorado Demography Office are (DOLA, 2015a):

Delta County	30,299 people
Garfield County	57,298 people
Gunnison County	15,454 people
Mesa County	147,811 people
Montrose County	40,754 people
Rio Blanco County	6,778 people

Employment and Income in the Economic Study Area

Understanding which industries are responsible for the employment and income in an area is important for grasping the type of economy that exists. Total employment and labor income for the study area in 2013 for major industry sectors is highlighted in **Table 4-1**. The table also highlights the average labor income (labor income per job) for the study area and for the State of Colorado for comparison. The overall average labor income in 2013 in the study area was $41,431 compared to the State average of $55,427. Industry average labor income for mining, construction, manufacturing, information, transportation and government (not including estimated industries) all show higher average labor income than both the State and the study area total employment averages. The largest study area industries in terms of employment (not including estimated industries) include construction, retail trade, real estate/rental/leasing, accommodation/food services, and government.

Table 4-1. *Total Employment and Labor Income by Industry for the Study Area for Colorado, 2013.*

Sector	Employment (Jobs)	Labor Income (1000's of 2013$s)	Labor income/job (2013 dollars)	
	2013 Study Area		Study Area	Colorado
Total Employment/Labor Earnings	176,431	7,309,689	41,431	55,427
Non-services related	~37,116	~1,933,688	~52,099	70,126
Farm	5,930	45,741	7,713	32,851
Forestry, fishing, & related activities	~1,316	~34,019	~25,850	27,206
Mining (including fossil fuels)	9,502	871,168	91,683	129,103
Construction	14,322	705,570	49,265	57,853
Manufacturing	6,046	277,189	45,847	76,550
Services related	~115,054	~3,937,186	~34,220	49,743
Utilities	~809	~84,865	~104,901	148,982
Wholesale trade	~4,453	~270,070	~60,649	86,963
Retail trade	19,423	574,568	29,582	32,895
Transportation and warehousing	5,330	330,277	61,966	66,888
Information	1,866	85,711	45,933	124,948
Finance and insurance	7,107	251,905	35,445	59,215
Real estate and rental and leasing	10,330	131,884	12,767	16,650
Professional and technical services	8,760	370,766	42,325	78,163
Management of companies and enterprises	1,268	47,799	37,696	129,107
Administrative and waste services	8,270	235,722	28,503	36,223
Educational services	~1,777	~34,565	~19,451	34,071
Health care and social assistance	~17,257	~867,300	~50,258	54,608
Arts, entertainment, and recreation	4,530	66,126	14,597	25,916
Accommodation and food services	13,651	297,331	21,781	25,388
Other services, except public administration	10,223	351,290	34,363	38,207
Government	24,084	1,357,331	56,358	66,003

The employment and income data presented here was obtained from the U.S. Department of Commerce, Bureau of Economic Analysis (BEA, 2014) Regional Economic Information System and represents the latest data that are currently available for counties in the United States (2013). Regional Economic Information System data were used because it provides estimates of all employment in a region, those who are wage and salary employees and those who are self-employed. Some data are withheld by the federal government to avoid the *disclosure of potentially confidential information. Headwaters Economics uses supplemental data from the U.S. Department of Commerce to estimate these data gaps. These values are indicated with tildes (~).*

Sources: U.S. Department of Commerce, Bureau of Economic Analysis (BEA, 2014); Headwaters Economics (2015).

The data in **Table 4-1** are the latest available, 2013, and do not include the most recent events within the study area that would impact the mining sector. Layoffs have occurred within the study area in the coal mining industry, as well as in oil/gas, and dairy production. The impact of the loss of direct jobs within any sector would be followed by changes to other sectors as the ripple effects of lost wages work their way through the economy. All data presented in this analysis represents a snapshot in time of the study area. Hiring, layoffs, and restructuring in any industry occur, and will continue to occur in the study area economy. Data presented here are best available, knowing that industries will continue to change with trends and markets and the larger economy.

Any new layoffs within a community can be difficult. Some areas work to diversify, with people finding or creating other opportunities in the same area. Layoffs from an industry can impact everything from real estate to the school system if people choose to leave the area. For example, the school district in Paonia is making adjustments to the coal industry layoffs as enrollment has dropped from 5,500 in 2009 to 4,800 in 2015 (Webb, 2015).

Unemployment within the study area has been higher than the State average for several years. The most recent monthly unemployment rates available for 2015 for both the State of Colorado and the study area from the Bureau of Labor Statistics are shown in **Table 4-2**.

Table 4-2. *2015 Monthly Unemployment Rates for Colorado and Study Area.*

	January	*February*	*March*	*April*	*May*	*June*	*July*
Colorado	4.7%	4.7%	4.5%	4.4%	4.3%	4.5%	4.0%
Study area	5.8%	5.9%	5.8%	5.6%	5.5%	5.8%	5.1%

Source: U.S. Department of Labor, Bureau of Labor Statistics (2015).

The average earnings per job measure is the compensation of the average job, total earnings divided by total employment. Full-time and part-time jobs are counted at equal weight. Employees, sole proprietors, and active partners are included. Per capita income is an important measure of economic well-being. Per capita income is total personal income divided by population. Because total personal income includes non-labor income sources (dividends, interest, rent, and transfer payments), it is possible for per capita income to be relatively high due to the presence of retirees and people with investment income. Because per capita income is calculated using total population and not the labor force as in average earnings per job, it is possible for per capita income to be relatively low when there are a disproportionate number of children and/or elderly people in the population.

For the study area, per capita income was $37,830 in 2013, compared to Colorado’s State per capita income of $47,647. The study area labor earnings were about 59% of personal income, compared to the State average of 66%. The unearned income in the study area, which accounts for 41% of total personal income, consists of dividends, rent, and interest (23% of total personal income) and government transfer payments, such as Social Security (18%), payments often associated with retirees. These payments are consistent with the presence of a population of people/retirees who are living in the study area by choice, for reasons not related to the need for employment. Retirees bringing their investment income into a community demand a variety of services from medical/health care to housing, entertainment, and services. Such demands can create a new source of economic opportunity for communities.

Federal Revenues (Coal Royalties) of the Study Area

Royalty rates for coal are managed by the BLM, and the required minimum royalty rate for underground mines is 8%. For all types of coal leases, BLM is authorized to reduce the royalty for the purpose of encouraging the recovery of federal coal, and in the interest of conservation of federal coal and other resources, whenever it is necessary to promote development, or when the lease cannot be successfully operated under its terms, but in no case can the royalty on a producing federal lease be reduced to zero 43 C.F.R. §§3473.3-2(e), 3485(c)(1) (2013). The BLM may approve royalty rate reductions for new leases; in Colorado for 2012 the effective royalty rate was 5.6% for underground mines.

Mineral royalties collected by the federal government are disbursed to a variety of funds. About half (49%) of the royalties of onshore lease revenue go to the state in which the lease is located. Forty percent of the total is disbursed to the National Reclamation Fund (used to fund water resource management projects in the United States), and the remaining 10 percent goes to the U.S. Treasury. Of the royalties paid to Colorado, 50% goes to state public school funding, and 10% funds the Water Conservation Board. The remaining 40% is put into local impact programs with half going directly to the counties and town or local mining area districts and the other half is available through a grant program for local governments (DOLA, 2015b). In addition, section 402 of the Department of Interior's Abandoned Mine Reclamation Program requires coal operators to pay 13.5 cents per ton or 10% of the value of non-lignite coal produced (underground), whichever is less, and 50% of the reclamation fees collected are returned to the States where is was collected (30 U.S.C. 1232).

Coal Production and Markets

Coal provided to the U.S. economy from any source, including roadless areas in Colorado, has national as well as local implications. This section briefly describes the economic context within which coal from the North Fork Coal Mining Area may be provided to the nation in the future. Additional information is provided in the *Coal Resources* section of the SFEIS and in **Error! Reference source not found.**.

North Fork Area Coal Characteristics

The North Fork area includes coal from the area around the North Fork of the Gunnison River in west central Colorado. The North Fork Coal Mining Area of Colorado is part of the larger Uinta Basin, which includes western Colorado and eastern Utah. See the *Coal Resources* section of the SFEIS for a description of North Fork coal.

Disposition of North Fork Coal and Potential for Substitution

Annual production of low sulfur bituminous coal from the Rocky Mountain coal region (Colorado and Utah) was about 40 million tons in 2012 (EIA, 2015b). Average annual production for the Rocky Mountain coal region is projected to be about 28.3 million tons on average over a 15-year period from 2013 to 2027, a 36% decrease in production, as estimated using projected production from the Annual Energy Outlook 2014 Reference case (EIA, 2014). Increases in average annual production from the North Fork area under Alternatives B and C over the next 15 years (2016–2030) are about 15 to 40% of the projected Annual Energy Outlook annual coal production from the Rocky Mountain region. For the United States as a whole, bituminous coal is projected to decrease by 1.4%, while low-sulfur coal production is estimated to decrease by 8.9% over that same period. Projected production from the North Fork area is estimated to be 0.45 to 1.1% of all coal and 1 to 2.4% of all bituminous coal produced in the United States in 2013 (EIA, 2015b).

The minemouth price of North Fork Coal Mining Area is less than coal of similar characteristics from Central Appalachia and the low sulfur content is important for meeting air emissions requirements. The minemouth price of Uinta Basin coal over 2008 to 2014 has been in the $30 to $40/ton range, except for late 2008 and early 2009 when Uinta Basin coal prices were between $50 and $70/ton during a general commodity price surge (Bloomberg, 2015). In contrast, Central Appalachian coal prices have been in the range of $50 to $80/ton in the same period, and surged to over $120/ton in 2008 (Bloomberg, 2015).

Based on coal consumption data for 2008–2014 compiled from Energy Information Administration form 923, 31 coal-fired power plants have been identified as potential consumers of North Fork Coal Mining Area coal (see SFEIS, **Error! Reference source not found.** C). These plants have received Uinta basin coal in 2013–14 and are not fully retiring. They are located across the Southeast (Alabama, Florida, Georgia, Maryland, and Mississippi), Central/Appalachian region (Kentucky and Tennessee), Midwest (Michigan and Wisconsin), Intermountain and Southwest region (Arizona, Colorado, and Utah), and California. At least one plant in each of these states, except Maryland, has received North Fork Coal Mining Area coal.

Some North Fork Coal Mining Area coal may be consumed at industrial facilities, but the amount is significantly less than amounts used for power generation; all North Fork Coal Mining Area coal is assumed to be consumed for power generation for the purposes of this supplement.

Uinta basin coal exports between 2008 and 2014 are estimated to range from five to 10 million tons per year, which is 10 to 20% of total coal production from the Uinta basin (analysis of emissions in the *Air* section assumed 12% export based on recent data, which is within the range of 10–20%). As demand for coal in Asia is expected to increase, it is likely that exports from Uinta basin, including the North Fork Coal Mining Area, will continue to occur, or even increase if U.S. coal demand declines in the long-run.

Change in consumption of fuels by power generating facilities in response to changes in fuel prices varies by supply region (e.g., natural gas-coal elasticity ranges from 0.05 to 0.38; -0.14 to -0.22 for coal's own price elasticity), as expected given differing market, technology, policy, and demand conditions across regions (see SFEIS, **Error! Reference source not found.** C). However, consumption of coal is generally, relatively unresponsive to prices (inelastic). This variation may increase when smaller sub-regions are considered, as the characteristics and impacts of smaller numbers of (or even individual) power generating facilities become more dominant.

The possible substitutes for North Fork Coal Mining Area coal at coal-fired power plants depend on a number of factors. At one extreme, only coal that has the same characteristics as the North Fork Coal Mining Area coal might be considered possible substitutes. However, other factors such as coal plant location, boiler design, coal handling and grinding equipment, air permit requirements, and environmental controls, all play an important role in determining the types of coal that might be substitutes for North Fork coal. Finally, other fuels may substitute for the consumption of North Fork Coal Mining Area coal for the production of electric power. These fuels include biomass, hydro, natural gas, nuclear, solar, or wind.

Eleven of the plants that are potential consumers of North Fork Coal Mining Area coal use a mixture of both bituminous and subbituminous coal, and thus could be able to substitute both types of coal for North Fork Coal Mining Area coal (see SFEIS, **Error! Reference source not found.** C). For coal plants that consume North Fork Coal Mining Area and other bituminous coal exclusively, the substitution options will be limited to other sources of bituminous coal, subject to the limitations of location as discussed above. These plants also may be able to substitute higher sulfur coal, such as from the Illinois Basin, depending on their air permit requirements and installed environmental controls. Coal plants consuming only bituminous coal can make modifications to use subbituminous coal, although this is not an option for all plants. Coal plants with environmental controls, such as sulfur dioxide (SO_2) scrubbers, bag houses, and NO_X controls, have more options for the types of coal that they can consume and still meet their emissions limits versus coal plants without these controls. Over the last 15 years, there has been a slow erosion of demand for low-sulfur Central Appalachian coal as more and more plants install sulfur dioxide scrubbers and are able to switch to higher sulfur alternatives from Northern Appalachia and the Illinois Basin. For coal plants with sulfur dioxide scrubbers, substitutes for North Fork Coal Mining Area coal might include lower sulfur coal from Central Appalachia and the Uinta Basin as well as higher sulfur coal from the Illinois Basin (see SFEIS, **Error! Reference source not found.** C).

Distributional Effects Results

Economic impacts, sometimes called distributional effects, include consequences to jobs and labor income within the economic study area. Jobs and income estimates for the economic impact area were completed using an IMPLAN model of estimated coal outputs by alternative. The economic impacts of each alternative are based on estimates of coal that may be leased and produced within the North Fork Coal Mining Area over the 15-year period. All recoverable coal within the North Fork Coal Mining Area was assumed to be economically viable. The coal resources are located in Gunnison County adjacent to the existing Elk Creek and West Elk mines. For the purpose of this analysis, the past production data for these two mines was used, but no assumptions are made that in the future new or different mines may operate in the area.

Analysis for the 2012 FEIS included the Bowie mine, as the scope of analysis for the 2012 FEIS was at a statewide scale, and the alternatives included consideration of an alternative to manage roadless areas according to existing forest plans. In addition, the North Fork Coal Mining Area (as outlined in **Error! Reference source not found.**) changed from the DEIS, the revised DEIS, and the 2012 FEIS, with some original areas included within the North Fork Coal Mining Area being of concern to the Bowie Mine. The boundaries of the North Fork Coal Mining Area have been decreased and those areas of interest to Bowie remain within CRAs, but are no longer within the North Fork Coal Mining Area. In this supplemental analysis, only past production data for Elk Creek and West Elk mines are included, as the Bowie mine is no longer affected by the North Fork Coal Mining Area; data for Bowie mine has not been included in this supplemental analysis.

Output, employment, and labor income impacts in the economic impact area from estimated coal production within the North Fork Coal Mining Area are shown in **Table 4-3** through **Table 4-5**. All indicators are expressed on an average annual basis over a 15-year analysis period (2016–2030). Only those impacts associated with potential development and production from the North Fork Coal Mining Area are included. The three tables highlight a range of production that may occur within the North Fork Coal Mining Area: **Table 4-3** displays the low scenario of 5.2 million tons/year, **Table 4-4** shows the average scenario of 10 million tons/year, and **Table 4-5** is the permitted scenario of 15 million tons/year (see **Error! Reference source not found.** for details of each scenario).

An estimate of the direct, indirect, and induced effects for the output (production value), employment, and labor income by alternative are displayed in **Table 4-3** through **Table 4-5**. Direct effects are realized by the extraction and sale of coal. Indirect effects are realized by local companies that provide goods and services to coal mining operations. Induced effects result from local spending of employee income paid by the companies directly and indirectly affected by mining activities.

The tables display an annual average impact. It should be noted that with only current leases, coal production would cease in 1 to 3 years under alternative A; with no additional lease opportunities, production would end with current leased coal. Coal production under alternative B could continue if leases were obtained; production could continue for an additional 12–36 years depending on the scenario. Alternative C displays the same annual average impacts as alternative B, but the timeframes under all three scenarios are shorter due to the decreased size of the North Fork Coal Mining Area. Under the scenarios in Alternative C, coal could be available for an additional 7 to 21 years.

Employment for the action alternatives may range between about 1,000 total jobs (direct, indirect, and induced) to 2,300 total jobs, depending on the production level (low, average, permitted). The impact could likely last over more years under alternative B than alternative C due to the overall amount of coal available over time with a larger coal mining area. Similar output estimates are displayed for the value of production and labor income.

Table 4-3. *Average Annual Economic Impacts Estimated by Alternative for North Fork Coal Mining Area Coal 2016–2030 (2013 dollars), Coal Production – Low Scenario.*

Activity/ Effects	*Value of Production ($ millions)*			*Employment (jobs)*			*Labor Income ($ millions)*		
	Alt A	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**
Direct	27	190	190	68	475	475	8	55	55
Indirect	5	32	32	24	165	165	1	10	10
Induced	5	32	32	50	346	346	2	12	12
Total	**37**	**254**	**254**	**142**	**986**	**986**	**11**	**78**	**78**

Table 4-4. *Average Annual Economic Impacts Estimated by Alternative for North Fork Coal Mining Area Coal 2016–2030 (2013 dollars), Coal Production – Average Scenario.*

Activity/ Effects	*Value of Production ($ millions)*			*Employment (jobs)*			*Labor Income ($ millions)*		
	Alt A	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**
Direct	27	366	366	68	913	913	8	107	107
Indirect	5	61	61	24	318	318	1	20	20
Induced	5	62	62	50	665	665	2	24	24
Total	**37**	**489**	**489**	**142**	**1,897**	**1,897**	**11**	**150**	**150**

Table 4-5. *Average Annual Economic Impacts Estimated by Alternative for North Fork Coal Mining Area Coal 2016–2030 (2013 dollars), Coal Production – Permitted Scenario.*

Activity/ Effects	*Value of Production ($ millions)*			*Employment (jobs)*			*Labor Income ($ millions)*		
	Alt A	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**	**Alt A**	**Alt B**	**Alt C**
Direct	27	448	448	68	1,117	1,117	8	130	130
Indirect	5	74	74	24	389	389	1	24	24
Induced	5	76	76	50	814	814	2	29	29
Total	**37**	**598**	**598**	**142**	**2,320**	**2,320**	**11**	**183**	**183**

Federal mineral royalties have been estimated (8% for all new leases) using total production. Current leases (alternative A) would continue under the BLM's negotiated rate of 5.6%. Royalty payments, not including rents or bonus payments, at 8% to Colorado (49% of the total) from coal from the North Fork Coal Mining Area are estimated at $0 for Alternative A (no new leases), about $6.8 million for Alternative B and $0.5 million for Alternative C. It is likely that any new leases could undergo negotiations with the BLM and result in a lower rate, but that is not known at this time. Economic impacts to the local study area shown in **Table 4-3** through **Table 4-5** do not include government spending of Federal mineral payments to the state or local jurisdictions.

Summary of Distributional Effects

Alternative A – under the no action alternative, without the temporary road construction exception within the North Fork Coal Mining Area, no additional coal production is likely. Depending on production rates, current operations within CRAs would be completed in 1 to 3 years. About 140 total jobs and associated labor income would be lost with no additional production associated with the North Fork Coal Mining Area would be likely. Such declines within the coal mining industry would likely create job losses to secondary businesses and additional social impacts to community structure. Although not all communities within the economic study area would be affected the same, some communities have diversified economies, attracted retiree populations, or are less dependent on coal mining. Those communities that are still dependent on coal mining would be most directly affected.

Alternatives B and C – under either of the action alternatives, future coal production is likely within the North Fork Coal Mining Area with the reinstatement of the temporary road construction exception. Depending on production rates, additional coal production could be completed in 7 to 36 years. Potential effects would be relatively short-term to the economic study area. Continued opportunities for coal development in the North Fork Coal Mining Area under Alternative B or C could result in production for a stable workforce over the production time, as well as continued royalty payments to the State of Colorado. These economic impacts are estimated for gross North Fork Coal Mining Area coal production. External forces and trends may still have a greater impact in the future in terms of coal prices and natural gas substitution.

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