

APPENDIX C

Coal Production and Markets

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Acronyms and Abbreviations

\$/MMBtu	dollars per million Btus
AUD	Australian dollar
ABS	Automatic Block Signals
BCY	bank cubic yards
BLM	U.S. Department of the Interior, Bureau of Land Management
BLS	U.S. Bureau of Labor Statistics
BNSF	BNSF Railway Company
Boyd	John T. Boyd Company
Btu	British thermal unit
Btu/lb	British thermal units per pound
CAFE	Corporate Average Fuel Economy
C.F.R.	Code of Federal Regulations
CN	Canadian National
CNY	Chinese yuan
CO ₂	carbon dioxide
CO ₂ e	carbon dioxide equivalency
CoalDOM [®]	Coal Depletion Organization Model
EBITDA	estimated by averaging yearly gross margin before interest, taxes, depreciation, and amortization
EIA	U.S. Energy Information Administration
EIS	environmental impact statement
FOB	free on board
FPL	Florida Power and Light
GAR	gross as received
GMM [®]	Gas Market Model
IDR	Indonesian rupiah
IPM [®]	Integrated Planning Model
IRR	internal rate of return
JPY	Japanese yen
kWh	kilowatt hour
LMU	Logical Mining Unit

LNG	liquefied natural gas
MMBtu	million British thermal units
Montana coal	Coal produced in Montana but excluding the Tongue River Basin
MWh	megawatt hour
NAR	net as received
NO _x	nitrogen oxide
Norwest	Norwest Corporation
OEA	Office of Environmental Analysis
Powder River Basin coal	All coal produced in the Powder River Basin, including Tongue River coal
SMCRA	Surface Mining Control and Reclamation Act
SO ₂	sulfur dioxide
STB	Surface Transportation Board
TCS	Traffic Control Systems
Tongue River Coal	Coal that could be induced by the development of the Tongue River Railroad
TRRC	Tongue River Railroad Corporation
T/S	truck-shovel
USD	U.S. dollar
USEPA	U.S. Environmental Protection Agency
WACC	weighted average cost of capital
Wyoming 8400	coal produced in Wyoming with a heat rating of 8,400 Btu/lb
Wyoming 8800	coal produced in Wyoming with a heat rating of 8,800 Btu/lb

1.1 Introduction

This appendix presents the Surface Transportation Board's (Board's) Office of Environmental Analysis (OEA) analysis of potential changes in coal production, coal markets, and rail transportation of coal that could occur if the Tongue River Railroad Company, Inc. (TRRC) were to construct and operate the Tongue River Railroad. This appendix also addresses coal production and markets under the No-Action Alternative (denial of the railroad license application), and documents the methods and data used in the analysis.

This analysis raises and addresses the following questions regarding the proposed Tongue River Railroad.

- Would the development of the Tongue River Railroad facilitate, i.e., induce coal mining?

The development of the Tongue River Railroad could induce coal mining. Tongue River coal production would be economically viable in most market conditions from 2018 to 2037, as analyzed in this document. The term, *Tongue River coal* in this context refers to coal from the proposed Otter Creek Mine and coal from other mines yet to be developed that could be induced by the development of the proposed rail line.

- Would Tongue River coal change or displace coal mining in the Powder River Basin and the United States as a whole?

Each ton of Tongue River coal produced would reduce other Powder River Basin coal production by 0.76 ton on average, and other U.S. coal production by 0.95 ton on average.

- Would development of the Tongue River Railroad affect the amount of coal that the United States exports to other countries?

Tongue River coal would not affect the amount of Powder River Basin coal exported to the Pacific Basin, (i.e., Japan, China, South Korea, Thailand, Singapore, and the Philippines). As the export terminal capacity on the Pacific coast increases in each of the scenarios (Chapter 7, *Scenarios*, provides further details), the same amount of rail traffic would flow from the Powder River Basin to the Pacific Northwest, with or without the Tongue River Railroad.

- Where would Tongue River coal be distributed within the United States?

Tongue River coal would be distributed primarily to the Upper Midwest, (i.e., Iowa, Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin).

- How would Tongue River coal production affect rail traffic?

Tongue River coal production would mostly affect rail traffic near the Tongue River Railroad. Much of the existing Powder River Basin rail traffic would experience little change because Tongue River coal would displace significant amounts of Powder River Basin coal.

- How would the uncertainties of production costs, natural gas prices, and CO₂ prices affect Tongue River coal production and distribution for U.S. consumption or export?

Uncertainties such as coal production costs, natural gas prices, and CO₂ prices can affect coal mining and where coal is distributed. OEA analyzed these three factors at moderate levels and found that Tongue River coal production and export would remain virtually unchanged.

- How would total Powder River Basin coal production and transport change?

Total Powder River Basin coal production and transport would experience small changes across different levels of coal production and large changes depending on how many of the proposed coal terminals in the United States and Canadian Pacific Northwest are built or expanded.

To summarize, Tongue River coal production and associated rail traffic would be most likely to increase under high production and high terminal capacity growth scenarios. However, this increase represents a relatively small increase over the No-Action Alternative, and incrementally small increases over current coal production in the nation and in the world. OEA conducted extensive modeling to provide estimates of potential coal movements and impacts. Nevertheless, in all 21 primary sensitivity scenarios (Chapter 7, *Scenarios*), coal production levels and rail traffic would be affected by factors that cannot be predicted with certainty, including economic conditions, regulatory conditions, and access to coal.

1.1.1 Overview of the Proposed Action

Under the proposed action, TRRC would construct, and the BNSF Railway Company (BNSF) would operate, a single-track rail line to transport low-sulfur, subbituminous coal from proposed mine sites yet to be developed in Rosebud and Powder River Counties, Montana. Because the Tongue River region contains additional quantities of coal, future rail traffic could also include shipments of coal from other mines whose development could be induced by the availability of a nearby rail line. OEA analyzed the coal production that could be induced by construction and operation of the proposed rail line. The analysis considered the proposed Otter Creek Mine and two potentially induced mines: one at the Poker Jim Creek–O’Dell Creek coal deposit, and one at the Canyon Creek coal deposit. Although the Tongue River is part of the Powder River Basin, for purposes of this analysis,

OEA uses the term *Tongue River coal* to refer specifically to coal from areas where construction of the proposed rail line could induce new mining (Chapter 3, *Additional Coal Mining*, Figure 3-1).

Tongue River coal is geographically distinct from coal mined elsewhere in the Powder River Basin, most of which is extracted south of the Tongue River, in Wyoming. The term *Powder River Basin coal*, in this context, refers to all coal produced in the Powder River Basin, including Tongue River coal (Figure 1-1).

Significant coal production began in the Powder River Basin in 1970. Since then, production has increased to an average of 463 million tons¹ per year over the last 5 years, with a range of 425 million tons to 496 million tons per year. The Powder River Basin accounts for approximately 45% of total coal production in the United States and is the largest source of coal in the United States. The United States is currently the world's second-largest producer of coal, after China. Almost all Powder River Basin coal comes from surface mines; there is only one underground mine in the basin and additional underground mining is unlikely.

Nearly all Powder River Basin coal is shipped by rail, often over long distances. Coal is the largest commodity by tonnage transported by U.S. rail, accounting for 39.5% of rail shipments in 2013 (Association of American Railroads 2014). The proposed rail line would connect the existing rail network to sites of potential or proposed new coal mines. TRRC has stated that train traffic on the proposed rail line would consist of 26 round trips per week (26 empty and incoming, and 26 loaded and outgoing, totaling 52 train trips), or 7.4 trains per day (3.7 in each direction),² moving approximately 20 million tons of coal annually.

1.1.2 Domestic Markets

Tongue River coal could be delivered to domestic consumers. Approximately 93% of coal currently produced in the Powder River Basin is now shipped by rail to domestic electric power plants outside of the Powder River Basin, while 5% is used at plants within the Powder River Basin. The remaining 2% is exported for international consumption. Historically, this coal has displaced other U.S. coals at existing power plants³ and met demand from new coal-fired power plants that came online over the last 40 years. (Mine Safety and Health Administration 2013). OEA understands that relatively few new coal power plants will be constructed in the United States in the next 20 to 30 years as none are proposed that are not already under construction (SNL Energy 2013). In the domestic market, Tongue River coal would be sold to existing coal power plants, and would displace other sources of coal, including Powder River Basin coal already accessed by rail. The

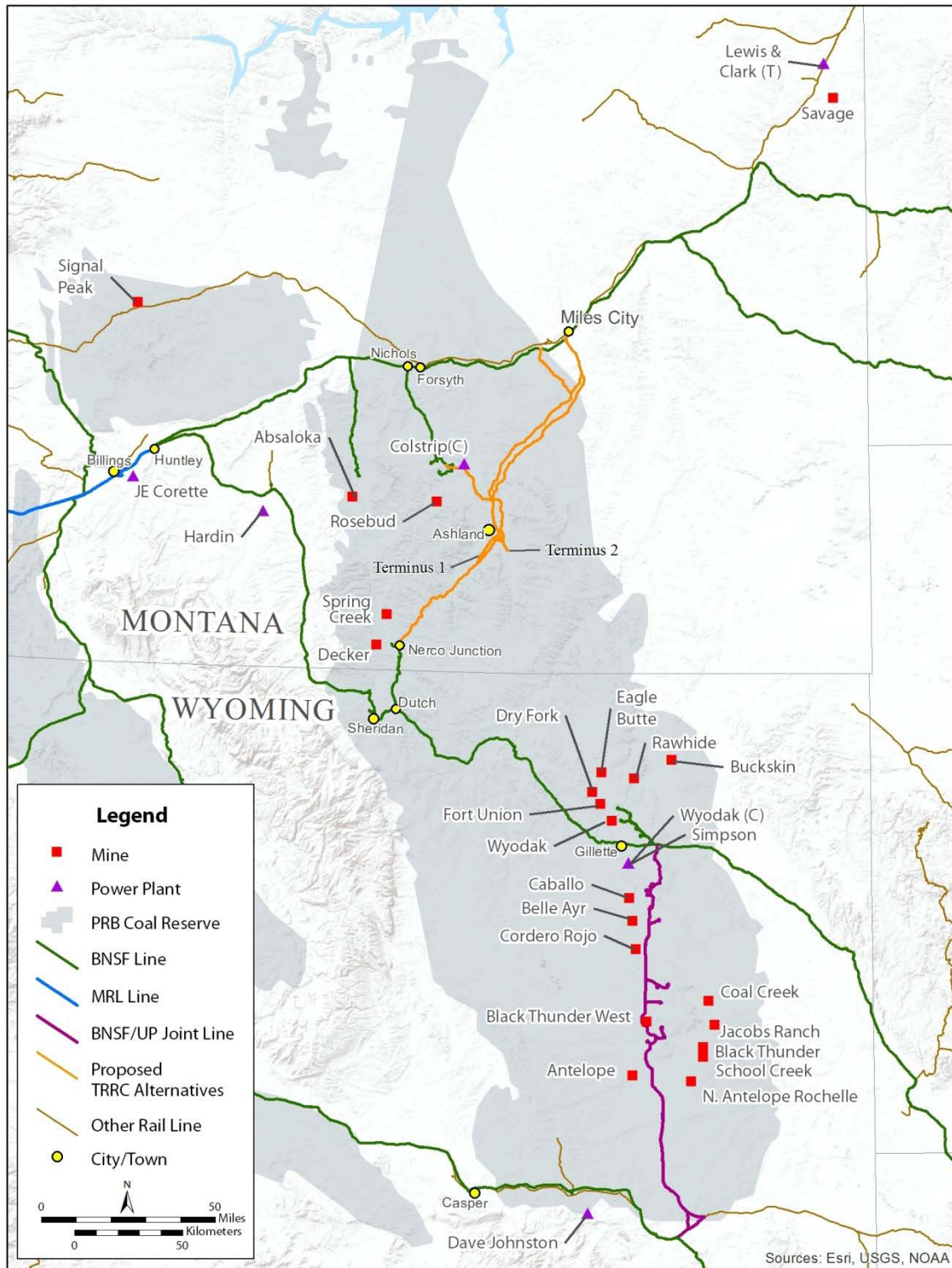
¹ The unit of measure *ton* refers to the U.S. *short ton*, which is 2,000 pounds.

² In this appendix, all train traffic numbers refer to individual train trips, whether incoming or outgoing, loaded or unloaded. The occasional use of the term *roundtrip trains* refers to two individual train trips, incoming and outgoing.

³ Analysis of Mine Safety and Health Administration (MSHA) Part 50 mine production data shows that Powder River Basin coal production has increased as eastern bituminous coal from Appalachia has decreased. Powder River Basin coal is subbituminous and has lower heat content than bituminous coal.

displacement would occur because Tongue River coal has competitive production costs and a rail distance advantage to key markets compared to other Powder River Basin coal.

Figure 1-1. Current Coal Mining and Rail Transport in the Powder River Basin



The minemouth prices of Powder River Basin coal are low compared to other U.S. minemouth coal prices.⁴ The low minemouth prices reflect the fact that Powder River Basin coal has the thickest seams at the shallowest depths of all U.S. coal mining areas. Powder River Basin minemouth coal prices have increased over the last 20 years, reflecting depletion of the lowest-cost resources. In addition to competitive pricing, Tongue River coal transportation costs would be lower because of shorter rail distances to certain U.S. coal power plants in the Midwest. Transportation costs generally represent between 40 and 65% of the total delivered cost of Powder River Basin coal (U.S. Energy Information Administration 2013a).

OEA concluded that Tongue River coal would be economically competitive for delivery to the Midwest, even with the capital investment needed for the mine and railroad facilities. OEA conducted the following analyses to reach this determination:

- Used a computer model that determined the least overall cost of meeting U.S. electricity demand that captures the dynamic interactions between Tongue River coal and the domestic and international coal markets. This analysis shows that Tongue River coal is economically competitive in all scenarios analyzed.
- Analyzed coal production costs that showed the costs of Tongue River coal production would be similar to or less than current costs for Powder River Basin coal.
- Conducted a resource analysis that concluded Tongue River coal is likely to be economically competitive based on the characteristics of overburden ratio,⁵ production quantity, distance to the railroad, and ability to obtain mining rights to the coal.

This appendix addresses all three analyses but focuses on the results from the first analysis: comprehensive computer modeling. This appendix also describes additional details for all three analyses. Chapter 8, *Coal Production and Transportation Modeling Results*, Chapter 9, *Rail Transportation Routes*, and Chapter 10, *Results of Emissions Forecast*, contain results from the first analysis. Chapter 6, *Coal Production Costs*, provides the results from the second analysis, and Chapter 3, *Additional Coal Mining*, provides the results from the third analysis.

1.1.3 Export Markets

Tongue River coal could be sold to international consumers. Historically, only a small amount⁶ of Powder River Basin coal has been exported, for the following reasons.

⁴ Minemouth price is the price of coal at the mine, including the costs of loading on a train, barge, or truck, but excluding transportation costs.

⁵ Overburden ratio refers to the ratio of the amount of earth that must be removed to the amount of coal that can be accessed.

⁶ International exports of Powder River Basin coal account for about 2% of total production (generally less than 10 million tons of exports out of production levels between 425 and 496 million tons), based on MSHA data as reported in Ventyx Velocity Suite Online and EIA U.S. Domestic and Foreign Coal Distribution by State of Origin data (Mine Safety and Health Administration 2013).

- The Powder River Basin is distant from the large U.S. coal export facilities on the Atlantic and in the Gulf Coast, which primarily serve European markets.
- Powder River Basin coal has a lower heat content than eastern bituminous coals. Lower heat content increases transportation cost per unit of energy delivered.⁷
- Powder River Basin coal is suitable only for use in thermal applications, such as boilers for electric power generation or industrial boilers for heat and power generation.⁸

Historically, U.S. coal exports have been of higher-heat-content bituminous coal and metallurgical coal for use in steel production, and have been exported primarily to Europe. However, two developments have increased the potential for lower-heat-content subbituminous coal from the Powder River Basin to be exported.

- **Price increase and international demand.** The price for coal delivered to export markets in the Pacific Basin⁹ increased between 2009 and 2011 by 70% to over 100%, depending on the source of the coal. Prices between 2011 and 2014 have generally fallen, but are still above the 2009 price levels. This price increase through 2011 is attributed to a greatly increased international demand for coal. Likewise, the decrease in price between 2011 and 2014 is due to softening demand from a general global economic slowdown. The increase in coal demand is exemplified by China, which was a net exporter before 2009, but imported nearly 200 million tons in 2011 (U.S. Energy Information Administration 2011a). Japan also imports approximately 200 million tons of coal per year, and historically has been the largest coal importer in the world. South Korea, India, and Taiwan are the world's third, fourth, and fifth largest coal importers, respectively. Total consumption of coal in the Pacific Basin, domestic and imported, is approximately five times U.S. consumption. China alone consumes approximately four times the amount of coal as the United States (U.S. Energy Information Administration 2010).
- **Terminal development.** Several coal export terminals have been proposed for new construction or expansion in the Pacific Northwest.¹⁰ Currently, Pacific Northwest coal export capacity is limited and fully used. Terminal developments could increase demand for Powder River Basin coal by providing a cost-effective route to Pacific Basin markets. The Powder River Basin is closer to Pacific Basin countries than other U.S. coal sources. Even with recent increases in minemouth prices, Powder River Basin coal still has the lowest cost of fossil energy resources in the United States when prices are measured at

⁷ Cost per unit of energy delivered is proportional to the tons transported and the heat content. If the energy or heat content per ton is low, the cost per unit of energy is higher.

⁸ Most U.S. coal is "steam" or "thermal" coal that is used in electric power plants. The other primary type of coal is "coking" or "metallurgical" coal that is used to produce coke, which, because of its high carbon content, burns hotter and is used to produce steel.

⁹ In this study, the Pacific Basin countries refer to Australia, Bangladesh, China, Hong Kong, India, Indonesia, Japan, South Korea, Laos, Myanmar, Singapore, Taiwan, Thailand, and Vietnam.

¹⁰ Future references to export terminals in the Pacific Northwest include current and proposed export terminals in Washington, Oregon, and Vancouver, British Columbia. Ridley terminal is excluded from the reference to Pacific Northwest export terminals coal for reasons described in Chapter 4, Section 4.2, *Coal Export Terminals in the Pacific Northwest*.

the origin. While other coal producers (Australia, Canada, China, and Indonesia) are currently competitive in the Pacific Basin, the expansion of the Pacific Northwest export terminals would allow Tongue River coal to be delivered to the Pacific Basin at competitive prices.

Two major factors would affect the competitiveness of Tongue River coal compared to other Powder River Basin coals.

- **Proximity.** Tongue River coal would be closer to export terminals than most other U.S.- coal sources, including coal currently produced in the Wyoming portion of the Powder River Basin. Proximity to terminals makes Tongue River coal more attractive for exporting.
- **Heat content.** Coal with above-average heat content, is more suited for export, while coal with below-average heat content is more suited to domestic use. This is because higher heat content justifies the high transportation costs of international shipments. Among the potential Tongue River coal sources, Otter Creek and Poker Jim Creek–O’Dell Creek coal have average to low heat content compared to other Powder River Basin coals, and Canyon Creek coal has above-average heat content. Based on heat content, some Tongue River coals are more suitable for domestic consumption and others are more suitable for international consumption.

1.2 Summary

This section summarizes the remaining chapters of the appendix.

1.2.1 Chapter 2. Historical Powder River Basin Production and Markets

Chapter 2 documents the historical trends in Powder River Basin coal production, distribution, rail transportation, and market prices. The domestic and Pacific Basin markets have changed sufficiently in recent years to make Tongue River coal more economically competitive. Specifically, Pacific Basin coal prices are higher, Pacific Basin demand for coal is higher, and other Powder River Basin coal prices have higher shipping costs to markets.

1.2.2 Chapter 3. Additional Coal Mining

Chapter 3 describes coal resources in the project area that could be economically developed. OEA also considered the likelihood that other sites in the area could be developed for coal mining. The three most likely sources of future Tongue River coal are the Otter Creek Mine, Poker Jim Creek–O’Dell Creek deposit, and Canyon Creek deposit (Chapter 3, *Additional Coal Mining*, Figure 3-3). At this time, the only coal mine that has applied for a new mine permit is Otter Creek Mine. OEA examined other sites in the area for their likeliness to be developed because of the proposed rail line. OEA, however, excluded these sites from

further analysis based on access to the coal,¹¹ overburden ratio, quantity of coal, distance to the proposed rail line, seam thickness, and the attractiveness of the coal to users, which is affected by the heat content of the coal and the presence of metals and minerals.

1.2.3 Chapter 4. Proposed Coal Export Terminals and Expansions

Chapter 4 discusses coal export capacity. Existing coal terminals are located in Prince Rupert and Vancouver, British Columbia, Canada. These terminals have limited capacity for overseas U.S. coal exports, in spite of recent capacity expansions. Four new terminals have been proposed in the Pacific Northwest, thus, additional terminal capacity is reasonably foreseeable. OEA considered three cases for future Pacific Northwest coal export capacity.

- **Zero growth.** The scenarios using zero port growth assume no growth in terminal export capacity, with exports remaining at the historical average (2008 to 2012) of 8 million tons per year. These scenarios assess the economic viability of Tongue River coal assuming existing export capacity.
- **Medium growth.** The scenarios using medium port growth assume half of the total proposed export capacity would be developed in the Pacific Northwest. Under these scenarios, coal export capacity would increase to 65 million tons per year.
- **High growth.** The scenarios using high port growth assume the completion of all of the proposed new coal export terminals in the Pacific Northwest. Under these scenarios, coal export capacity would increase to 122 million tons per year.

1.2.4 Chapter 5. Model Framework, Methods, and Key Assumptions

Chapter 5 summarizes the model, methods, and assumptions that governed OEA's analysis of coal production, transport, and consumption. OEA's analysis forecasts air emissions, including carbon dioxide (CO₂), which would result from direct combustion of fuel. The analysis also examines the impacts of economic and regulatory uncertainties with a focus on low natural gas prices and CO₂ emission regulations.

OEA used ICF International's Integrated Planning Model (IPM[®]) to assess coal production, rail traffic, and distribution patterns that could be induced by the Tongue River Railroad. IPM[®] is widely used, both in the United States and globally, by private sector companies such as electric utilities, coal power plants, coal companies, independent power producers, and financial institutions, as well as public sector entities such as the U.S. Environmental Protection Agency (USEPA), environmental groups, and state public service commissions.

¹¹ Access to coal refers to the ability to obtain the rights to mine the coal resource. For example, it is illegal to mine coal (i.e., the coal is not accessible) in the Custer National Forest.

OEA used the IPM[®] model because no other available model endogenously (i.e., within one computer run) addresses so many factors affecting Tongue River Railroad coal production.

1.2.5 Chapter 6. Coal Production Costs

Chapter 6 describes the costs of producing Tongue River coal. The analysis highlights one unique characteristic of the coal proposed to be transported by the Tongue River Railroad relative to its previous proposals. While the costs of producing Powder River Basin coal have risen in direct proportion to rising overburden ratios, the primary driver of production costs—i.e., the estimated production cost for Tongue River coal—has remained relatively constant. As a result, the estimated production costs of Tongue River coal (about \$11 to \$14 per ton in real 2012 dollars for production at Otter Creek Mine) are more competitive than Powder River Basin coal.

1.2.6 Chapter 7. Scenarios

Chapter 7 describes 18 scenarios based on three sets of variables: the route (northern alternatives or southern alternatives), the maximum coal production level (low, medium, or high), and terminal capacity growth (zero, medium, or high). The analysis also assesses two other variables: sensitivities to natural gas prices and costs associated with potential national CO₂ emission regulations (referred to as the CO₂ price). These provide three additional scenarios (two natural gas price scenarios and one CO₂ regulatory scenario).¹² The 21 scenarios (18 plus 3) are referred to as the *primary sensitivity scenarios*, all of which include the licensing, construction, and operation of the Tongue River Railroad. OEA did not assign any probabilities to these scenarios. In other words, OEA does not assume one particular scenario as more likely to occur than another.

OEA also examined the No-Action Alternative under which the Tongue River Railroad would not be built and Tongue River coal production would not occur. There are six total scenarios under the No-Action Alternative, one each for the three terminal capacity growth cases (zero, medium, or high growth), as well as two for the natural gas price scenario and one for the CO₂ regulatory scenario. As part of its analysis, OEA evaluated whether there would still be sufficient coal exports to the Pacific Basin if the proposed terminals were constructed but the proposed Tongue River Railroad was not. Table 1-1 lists all scenarios.

¹² While maximum coal production levels were determined in Chapter 3, *Additional Coal Mining*, IPM[®] then determines how much of the maximum is actually economical.

Table 1-1. Scenarios

Scenario	Name	Description
Primary Sensitivity Scenarios		
3	N, Low, Zero	Northern alternatives, low production, zero terminal capacity growth
4	N, Low, Medium	Northern alternatives, low production, medium terminal capacity growth
5	N, Low, High	Northern alternatives, low production, high terminal capacity growth
6	N, Medium, Zero	Northern alternatives, medium production, zero terminal capacity growth
7	N, Medium, Medium	Northern alternatives, medium production, medium terminal capacity growth
8	N, Medium, High	Northern alternatives, medium production, high terminal capacity growth
9	N, High, Zero	Northern alternatives, high production, zero terminal capacity growth
10	N, High, Medium	Northern alternatives, high production, medium terminal capacity growth
11	N, High, High	Northern alternatives, high production, high terminal capacity growth
12	S, Low, Zero	Southern alternatives, low production, zero terminal capacity growth
13	S, Low, Medium	Southern alternatives, low production, medium terminal capacity growth
14	S, Low, High	Southern alternatives, low production, high terminal capacity growth
15	S, Medium, Zero	Southern alternatives, medium production, zero terminal capacity growth
16	S, Medium, Medium	Southern alternatives, medium production, medium terminal capacity growth
17	S, Medium, High	Southern alternatives, medium production, high terminal capacity growth
18	S, High, Zero	Southern alternatives, high production, zero terminal capacity growth
19	S, High, Medium	Southern alternatives, high production, medium terminal capacity growth
20	S, High, High	Southern alternatives, high production, high terminal capacity growth
21	N, Low, Zero, Low Gas	Northern alternatives, low production, zero terminal capacity growth, low natural gas prices
22	N, Low, High, Low Gas	Northern alternatives, low production, high terminal capacity growth, low natural gas prices
23	N, Low, High, Yes CO ₂	Northern alternatives, low production, high terminal capacity growth, CO ₂ price
No-Action Alternative Scenarios		
1	N/A, Zero	No-Action Alternative, zero terminal capacity growth
2	N/A, High	No-Action Alternative, high terminal capacity growth
24	N/A, High, Yes CO ₂	No-Action Alternative, high terminal capacity growth, CO ₂ price
25	N/A, Medium	No-Action Alternative, medium terminal capacity growth
26	N/A, Zero, Low Gas	No-Action Alternative, zero terminal capacity growth, low natural gas prices
27	N/A, High, Low Gas	No-Action Alternative, high terminal capacity growth, low natural gas prices

1.2.7 Chapter 8. Coal Production and Transportation Modeling Results

Chapter 8 presents the modeling results for potentially induced Tongue River coal production levels, displacement of other coal production by Tongue River coal production, and net incremental changes in coal production, rail transportation volumes, and coal distribution

patterns that would result from construction of the proposed Tongue River Railroad. OEA found that the production and shipment of Tongue River coal would be economically viable, to some degree, in all scenarios, and would primarily displace other U.S. production. OEA's specific findings are as follows.

- **Coal production.** OEA identified a range of potential production levels for Tongue River coal, depending on the scenario. Across all 21 primary sensitivity scenarios, the lowest estimated production level would be 13.8 million tons of coal per year, averaged over 20 years from 2018 to 2037.¹³ The highest estimated production level would be 57.0 million tons per year averaged over 2018 to 2037.

The production level would also vary from year to year. Across all 21 primary sensitivity scenarios, the lowest estimated production level in a single year would be 4.6 million tons. The highest estimated production level in a single year would be 72.0 million tons.

The potential production level would also depend on the alternative. If a northern alternative is licensed, annual production would range from a low of 20.0 million tons per year (scenarios 3 through 8) to a high of 50.0 million tons per year (scenarios 9, 10, and 11), depending on the scenario. If a southern alternative is licensed, production would range from a low of 4.6 million tons per year (scenario 12) to a high of 72.0 million tons per year (scenarios 19 and 20), depending on the scenario.

On average, the northern alternatives would be more economically viable than the southern alternatives because they would require lower capital costs to build the proposed rail line and would have shorter distances to several key markets. From 2018 to 2037, the average annual coal production would be 28.5 million tons per year for the northern alternatives (ranging from 20 million tons per year to 46 million tons per year) and 33.5 million tons per year for the southern alternatives (ranging from 13.8 million tons per year to 57 million tons per year).

The Tongue River Railroad construction costs for the northern alternatives would range from a low of \$403.3 million to a high of \$908.7 million.¹⁴ TRRC provided the \$403.3 million estimate for the Colstrip Alternative and the \$908.7 million estimate for the Tongue River Road East Alternative. Construction costs for the two southern alternatives would be \$730.0 million and \$762.2 million, as provided by TRRC.¹⁵ OEA chose to use

¹³ OEA's analysis period is 20 years, 2018 to 2037, and is based on Otter Creek Mine Company's mine plan submitted for its mining permit application. The application assumes Otter Creek Mine as permitted and operational in 2018. The mine plan submitted for its permit application forecasts mining for a 55-year period with Tract 2 under production within the first 20 years. Otter Creek would decide whether to mine beyond 20 years based on market conditions at that time.

¹⁴ This analysis uses a northern alternative construction cost of \$416 million. The Applicant later refined the lowest-estimated northern alternative cost to \$403.3. OEA reviewed the changes that would occur to the analyses if the \$403.3 million had been used and determined that the results would be materially the same.

¹⁵ This analysis uses a southern alternative construction cost of \$698 million. The Applicant later refined the lowest-estimated southern alternative cost to \$730.0. OEA reviewed the changes that would occur to the analyses if the \$698 million had been used and determined that the \$698 million construction cost is more conservative from a standpoint of potentially induced mine production

the lowest-estimated northern and southern alternative Tongue River Railroad capital cost as representative of all northern and southern alternatives. This choice results in the production of greater amounts of Tongue River coal than could be induced if OEA had used the higher cost estimate (i.e., it tends to overstate the production of Tongue River coal).

- Coal displacement.** OEA concluded that Tongue River coal production would substantially displace other U.S. coal production. For example, if Tongue River coal production is 20 million tons, total U.S. coal production would only increase by 1 million tons due to the displacement of other coal production. From 2018 to 2037, across all 21 scenarios, on average, every ton of Tongue River coal produced would displace 0.76 ton of other Powder River Basin coal. Due to displacement of non-Powder River Basin coal, 0.95 ton of total U.S. coal, including Powder River Basin coal, would be displaced.

The range of displacement would be from 0.57 ton (scenario 14) to 0.88 ton (scenario 4) per ton of other Powder River Basin coal, and from 0.90 ton (scenario 14) to 1.00 ton (scenario 3) of other U.S. coal per ton of Tongue River coal. In other words, for each ton of Tongue River coal produced, production of other Powder River Basin coal would decrease by an average of 0.76 ton and production of other U.S. coal would decrease by an average of 0.95 ton. Therefore, due to the displacement of the production of other coal, production of Tongue River coal would cause total U.S. coal production to increase, on average, by 1.4 million tons per year from 2018 to 2037 (1.4 million tons per year = 4.6% x 30.6 million tons per year).

The increase in Powder River Coal production would range from an annual average of 2.4 million tons (scenario 4) to 14.8 million tons (scenario 20) and the increase in other U.S. coal production would range from zero (scenario 3) to 3.8 million tons (scenario 11). Single-year changes in U.S. production relative to the scenarios under the No-Action Alternative would range from a decrease of 2.7 million tons per year (scenario 12, in 2030) to an increase of 8.8 million tons per year (scenario 11, in 2018). The increase of up to 8.8 million tons per year would be small in comparison to total U.S. and world coal consumption.

Under the six No-Action Alternative scenarios, U.S. coal production would average 1.04 billion tons per year, and would range from 0.97 billion tons per year (scenario 26) to 1.12 billion tons per year (scenario 2). Therefore, the average increase of 1.4 million tons per year in the action scenarios would be equal to approximately 0.13% of total U.S. coal production, and the maximum average annual increase of 3.8 million tons year per increase would equate to approximately 0.36% of total U.S. coal production. Both of these increases would be small relative to total U.S. coal production levels.

Tongue River coal production would have an even smaller incremental effect on world coal production, which is projected to average 11.4 billion tons per year from 2018 to 2037. The small impact on U.S. and world coal production reflects two factors. First, the cost advantage of producing Tongue River coal would be significant enough to

out-compete other coals, but would not be significant enough to noticeably lower delivered coal prices (which includes transportation), and thus, would not increase total demand for coal. This, in turn, is partly because the minemouth price is often less than half the delivered cost for coal originating in the Powder River Basin. Second, the quantities involved would be small compared to the size of the U.S. coal market, and any impact on total incremental demand for coal would be small.

- **Coal exports.** OEA concluded that exports of Tongue River coal would range from 0.0% (scenarios 3 to 6, 9, 12 to 18, and 21 to 23) to 53% (scenario 20) of Tongue River coal production. On average, from 2018 to 2037, 4% of Tongue River coal would be exported. The overall tons of Powder River Basin coal exported in each of the 21 scenarios—within the low, medium, and high port capacity growth scenarios—remains the same; however, the mix of coal changes based on the economics of the different Powder River Basin coals.

The amount of Tongue River coal exported would be low across most scenarios because other Powder River Basin coals with higher heat content would be more competitive for export. However, coal distribution would be sensitive to terminal capacity growth and the maximum amount and type of Tongue River coal production. Under the two scenarios with high Tongue River coal production and high terminal capacity growth (scenarios 11 and 20), the maximum share of annual potentially induced Tongue River coal that would be exported would increase to 38% and 53%, respectively (19 million of 50 million tons per year, scenario 11, and 38 million of 72 million tons per year, scenario 20). Scenario 20 assumes that, under the southern alternatives, exports would include the high-heat content coal from the Canyon Creek deposit.

OEA's conclusions on exports are based on the 21 scenarios, and assume uncertainties that cannot be fully captured in a modeling framework. For example, the forecasts assume competitive economics and certainty within each scenario. OEA notes, however, that Arch Coal is the developer or co-developer of the Tongue River Railroad, the Otter Creek Mine, and one of the export terminals (Millennium Bulk Terminal). Hence, Arch Coal might choose to export rather than sell domestically when there are opportunities to maximize profits over the suite of assets that include mines, railroads, and export terminals. Although only a portion of Tongue River coal is projected to be exported, all scenarios show that the export terminals would be fully used to export other Powder River Basin coal. In addition, export levels remain the same at the maximum export terminal capacity across pairs of no-action and action scenarios, as Wyoming or other Montana Powder River Basin coal would be exported in lieu of Tongue River coal in the no-action scenarios.

- **Domestic distribution.** OEA concluded that Tongue River coal would be mostly destined for domestic markets. For all 21 scenarios, from 2018 to 2037, an average of 96% of Tongue River coal would be shipped domestically; the remaining 4% would be exported. Annual domestic distribution of Tongue River coal would range from 47 to 100% and annual exports would range from zero to 53%.

- **Rail traffic.** OEA concluded that Tongue River Railroad train traffic would be 7.4 to 18.6 trains per day for the northern alternatives, and 7.4 to 26.7 trains per day for the southern alternatives, including outgoing trains loaded with coal and empty returning trains. The southern alternatives are estimated to have a higher number of trains per day because these alternatives could access three mines instead of the two mines that the northern alternatives would access. From 2018 to 2037, across all scenarios, an average of 11 trains per day could be induced. However, as the export terminal capacity becomes fully used in each of the scenarios, the same amount of rail traffic would flow from the Powder River Basin to the Pacific Northwest, with or without the Tongue River Railroad. The determining factor for the level of rail traffic from the Powder River Basin to the Pacific Northwest terminals is the level of export terminal growth.

This chapter also reports the modeling results according to the 21 primary sensitivity scenarios described earlier and in more detail in Chapter 7, *Scenarios*. Figures 1-2 through 1-7 also illustrate the possible distribution of Tongue River coal under different scenarios. All figures reflect a yearly average of coal production and distribution during the analysis period (2018 to 2037).

- **Figure 1-2.** This figure shows where coal would flow under the No-Action Alternative with zero terminal capacity growth (scenario 1). Exports of Powder River Basin coal to the Pacific Basin would be limited to 8 million tons per year. Although Pacific Northwest terminal capacity would be fully used, exports would equal historical levels because there would be no increase in terminal capacity.
- **Figure 1-3.** This figure shows where Tongue River coal would be distributed assuming the northern alternatives, low production, and zero terminal capacity growth (scenario 3). Tongue River coal would be sold domestically to the Midwest.
- **Figure 1-4.** This figure shows the difference between the yearly average coal distribution patterns shown in Figures 1-2 and 1-3, or between a No-Action Alternative scenario and a low-growth scenario (scenarios 1 and 3). Tongue River coal shipments to the Great Lakes region and Upper Midwest would primarily displace other Powder River Basin coal shipments to that region.¹⁶ The arrows in this figure show the change in coal distribution with the production of Tongue River coal.
- **Figure 1-5.** This figure shows where coal would flow under the No-Action Alternative with high terminal capacity growth (scenario 2). Powder River Basin coal shipments would increase and the increased Pacific Northwest terminal capacity would be fully used.
- **Figure 1-6.** This figure shows where coal would flow assuming the southern alternatives, high production, and high terminal capacity growth (scenario 20). Tongue

¹⁶ The Great Lakes region includes coal plants in Michigan and Wisconsin, as well as the Bay Shore plant in northern Ohio. The Upper Midwest includes coal plants in Minnesota.

River coal would be exported to the Pacific Basin (40%), and delivered domestically (60%).

- **Figure 1-7.** This figure shows the difference between the coal distribution shown in Figures 1-5 and 1-6, or between the No-Action Alternative scenario and a high-production, high-growth scenario. Tongue River coal would be distributed to both export terminals and domestically, and other Powder River Basin coal exports and domestic sales would be displaced.

In addition to reporting the results for the 21 primary sensitivity scenarios, this chapter summarizes the effects of the natural gas and CO₂ price sensitivities, as well as production cost sensitivities. OEA used a cost for emitting CO₂ to model potential greenhouse gas regulations. Although the regulatory mechanisms for these regulations are uncertain, they are expected to impose some burden on CO₂ emissions, which was monetized as a cost for purposes of modeling these regulations.

- **Natural gas price sensitivity.** OEA found that although U.S. coal production would decline when natural gas prices are lower, Tongue River coal would still be economically viable at the maximum permitted capacity of 20 million tons per year from Otter Creek Mine. Otter Creek Mine coal production of 20 million tons per year is economically viable at both the zero and high export terminal capacity growth rates.
- **Carbon dioxide price sensitivity.** OEA found that although U.S. coal production would decline, Tongue River coal production would still be economically viable at the maximum permitted capacity of 20 million tons per year from Otter Creek, despite a rising price on CO₂ emissions. The price for emitting CO₂ increases with time; therefore, it becomes more expensive to burn coal in the later years of the analysis.
- **Production cost sensitivity.** OEA found that the maximum permitted capacity of 20 million tons per year from Otter Creek would be economically viable in all years even in the unlikely event that production costs rise by 20%, an increase of \$2 per ton or \$0.13 per million British thermal units (MMBtu). Otter Creek coal would no longer be cost competitive when production costs increase by 80 to 100% or when international production costs decline by 40%.

In summary, OEA cannot predict the exact level of Tongue River coal production and rail traffic due to economic, regulatory, and access uncertainties. However, OEA concluded that annual coal production of at least 20 million tons is likely and rail traffic of 7.4 trains per day or more can be expected if the Tongue River Railroad is constructed.

Figure 1-2. Coal Production and Regional Distribution—Scenario 1: No-Action Alternative with Zero Terminal Capacity Growth

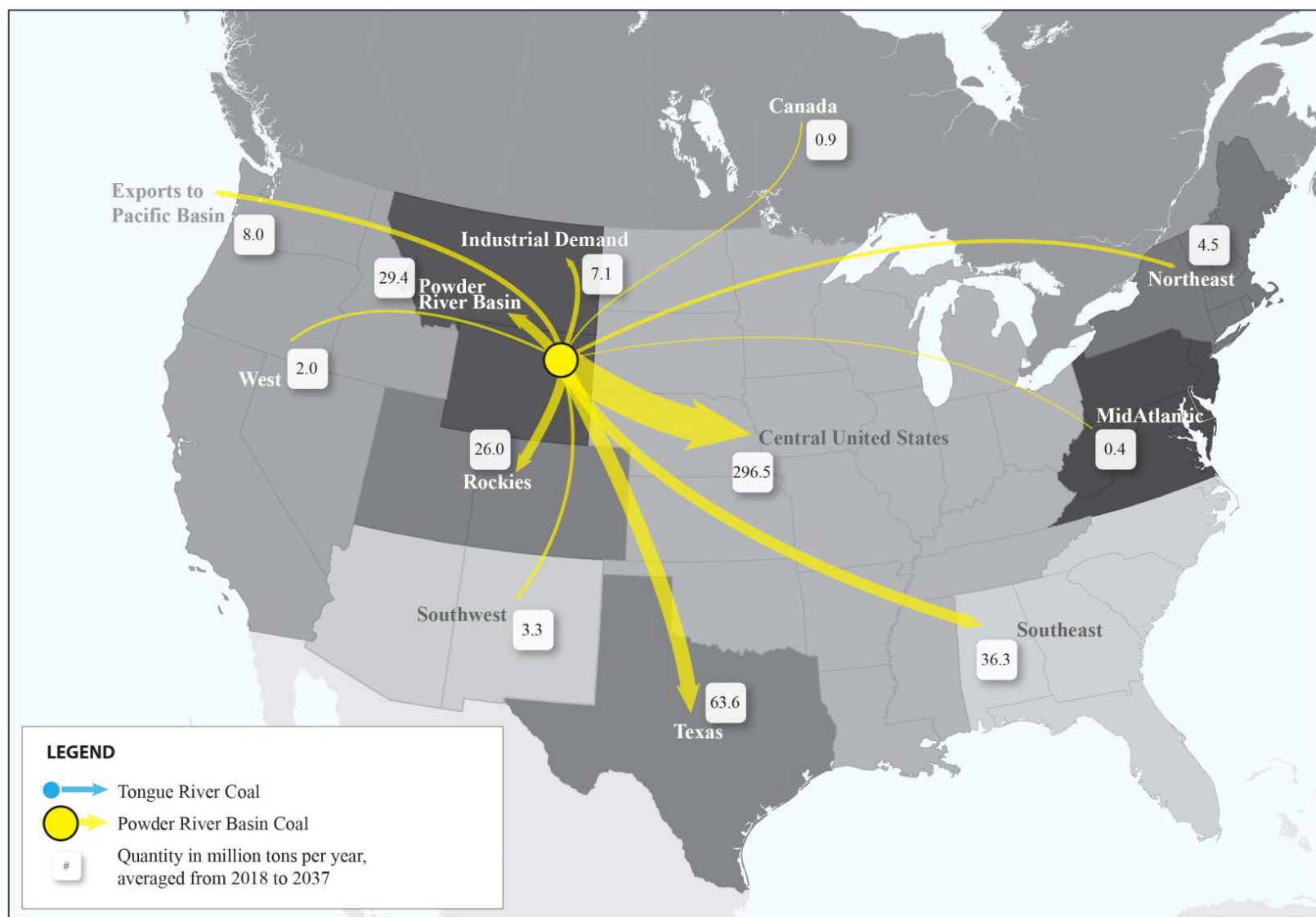


Figure 1-3. Coal Production and Regional Distribution—Scenario 3: Northern Alternatives, Low Production, Zero Terminal Capacity Growth

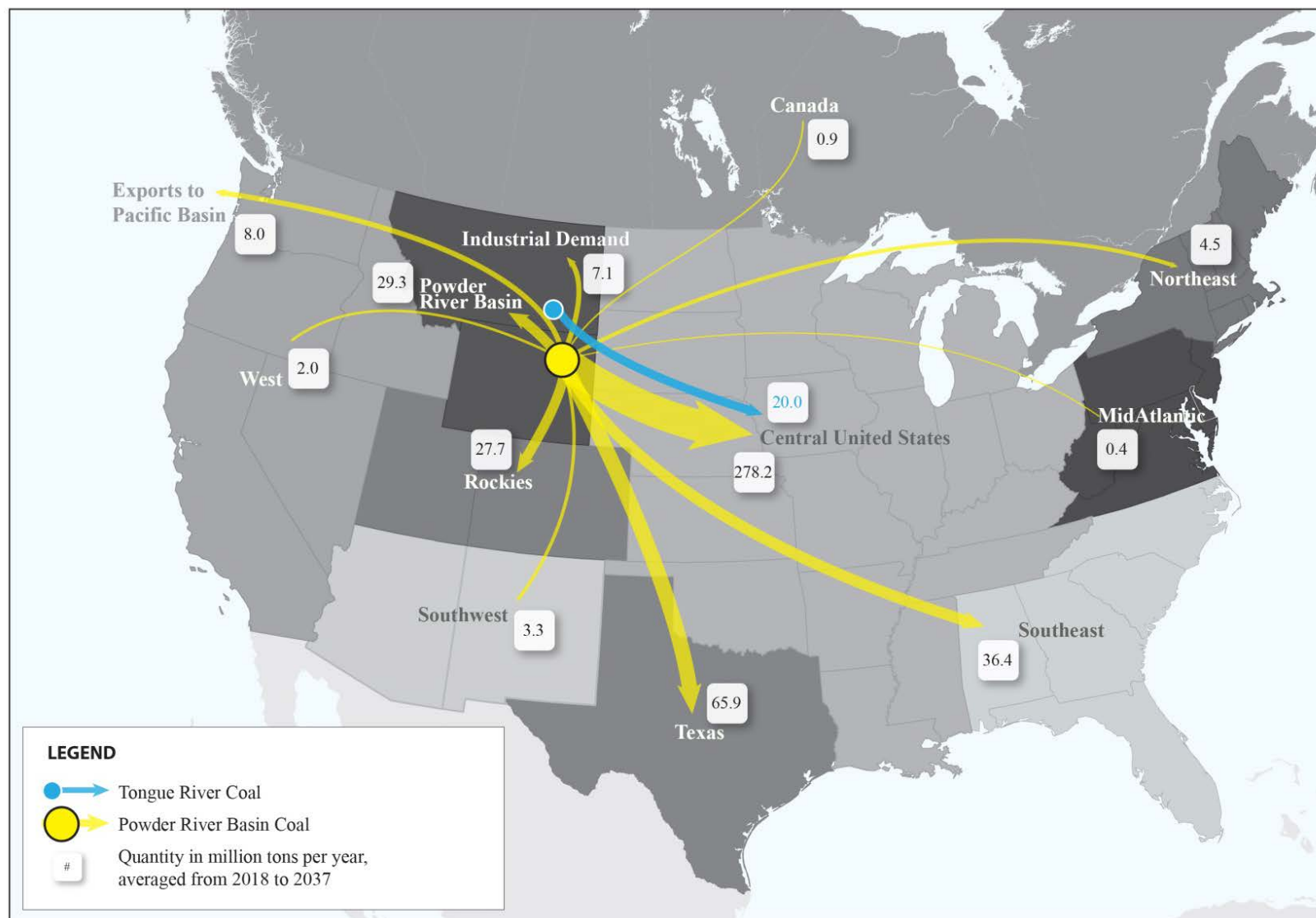


Figure 1-4. Coal Production and Regional Distribution—Difference between Scenarios 1 and 3

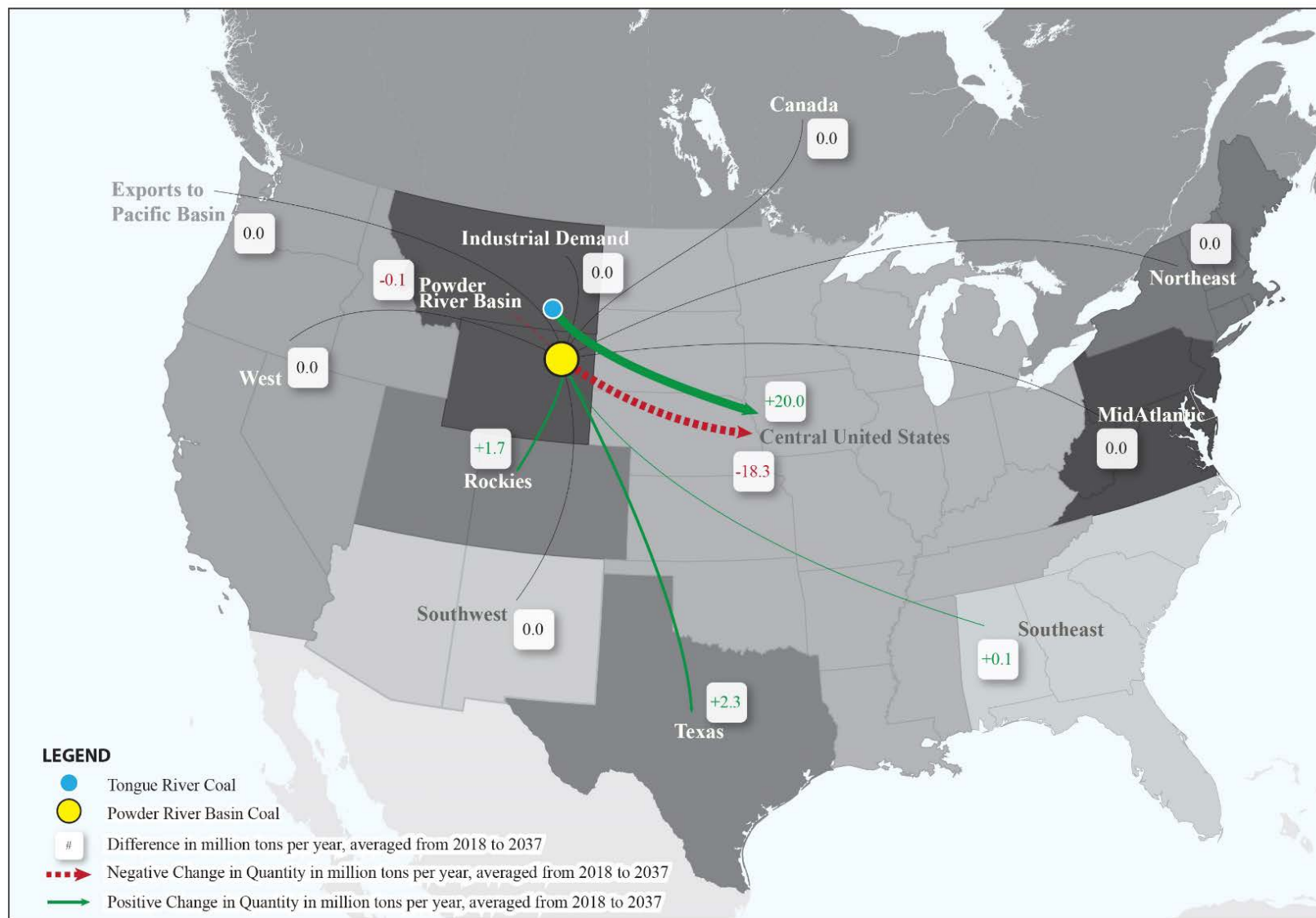


Figure 1-5. Coal Production and Regional Distribution—Scenario 2: No-Action Alternative with High Growth

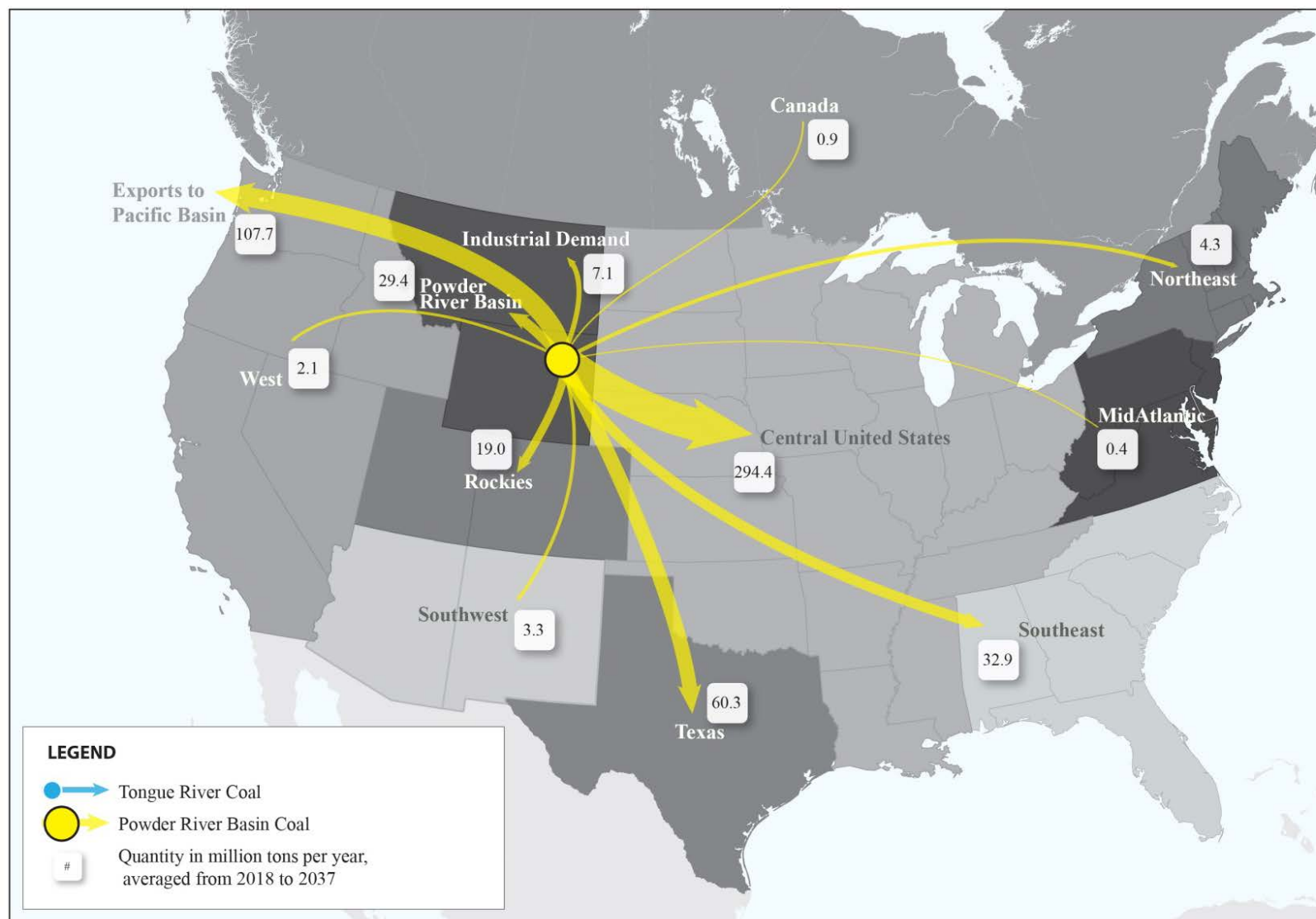


Figure 1-6. Coal Production and Regional Deliveries—Scenario 20: Southern Alternatives, High Production, High Terminal Capacity Growth

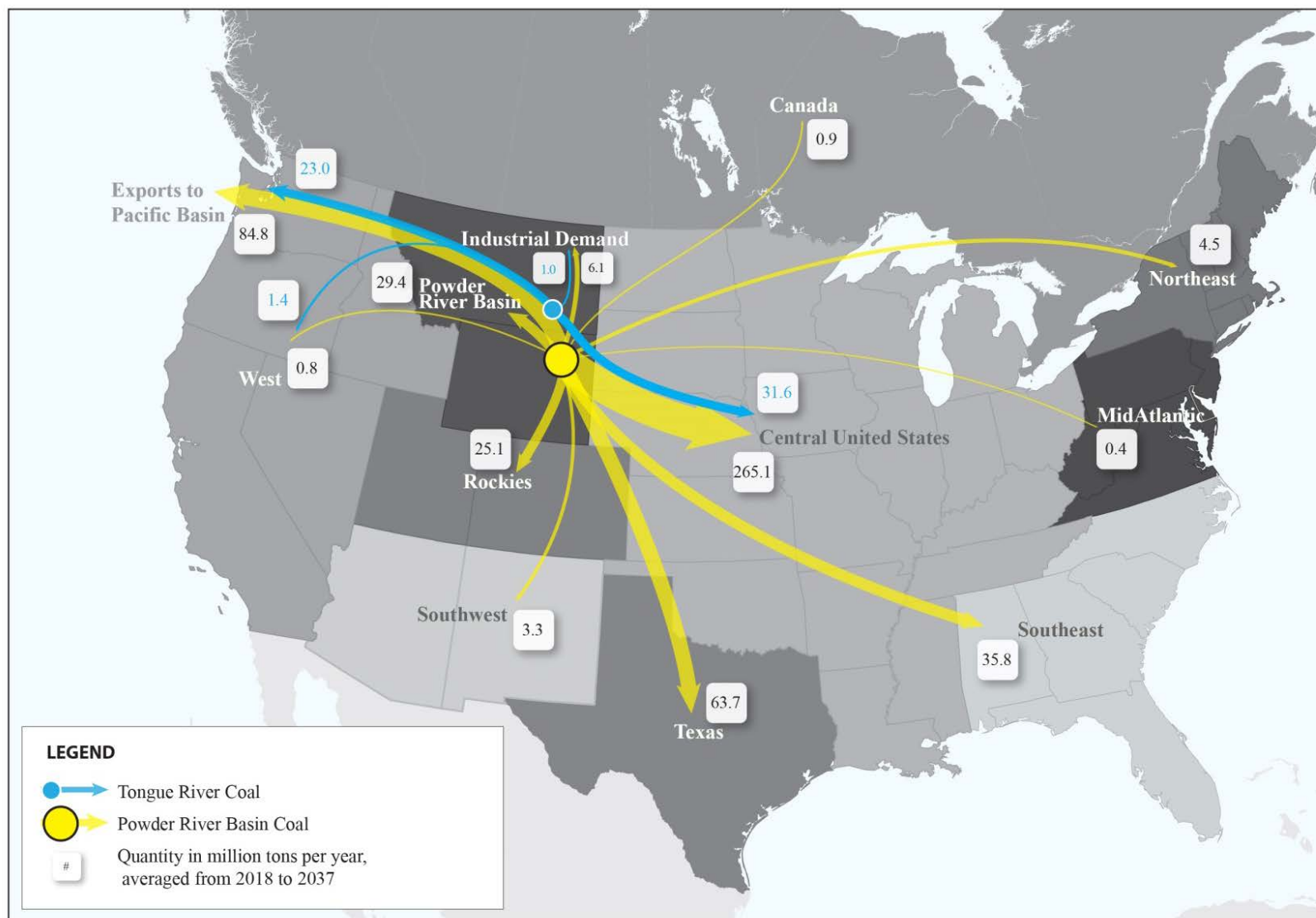
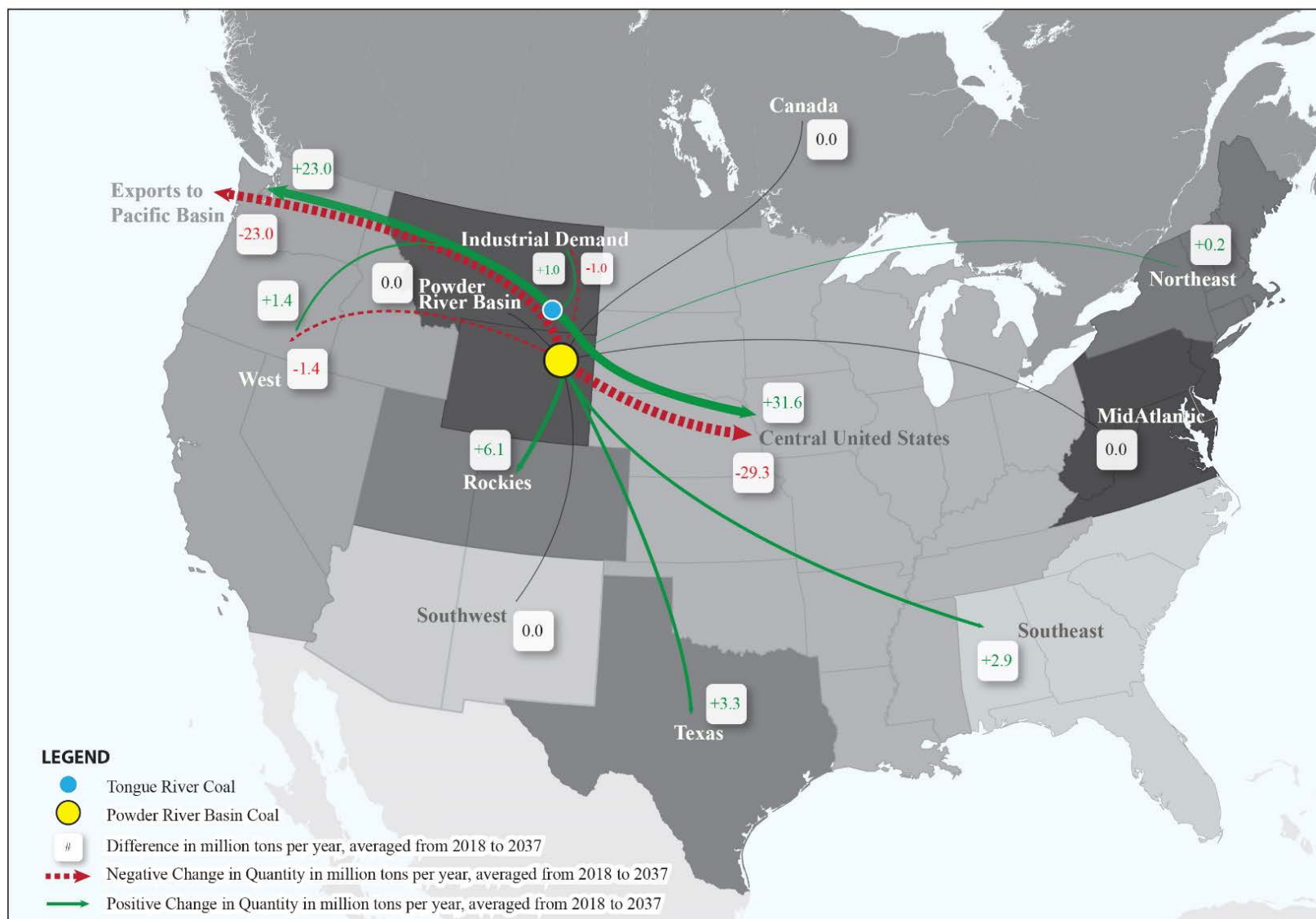


Figure 1-7. Coal Production and Regional Deliveries—Difference between Scenarios 2 and 20



1.2.8 Chapter 9. Rail Transportation Routes

Chapter 9 analyzes potential rail transportation routes to two major markets, domestic and international. The analysis includes 53 eastbound and westbound segments relative to the Tongue River area. Appendix E, *Air Quality*, Appendix D, *Grade-Crossing Safety and Delay Analysis*, and Appendix H, *Noise and Vibration Impact Assessment*, provide an analysis of rail segments for Tongue River coal movement that trigger the Board's analytical thresholds.

- **Domestic.** Railroads would transport Tongue River coal primarily to existing power plants in the Great Lakes region and Upper Midwest already using Powder River Basin coal. These routes would not change rail traffic patterns considerably, except locally near the mines.
- **International.** Railroads could transport Tongue River coal to the coal export terminals in the Pacific Northwest. Only the routes to the Vancouver bulk terminals and the proposed terminal expansions in Washington and Oregon would be economically competitive under normal market conditions. OEA found that exports through existing coal terminals at Ridley Terminal near Prince Rupert, British Columbia, the Great Lakes, Baltimore, Maryland, Norfolk, Virginia, and the U.S. Gulf Coast would not be economically viable except under temporarily upset market conditions related to production problems, rail congestion, or other unusual market conditions. Although the Gulf Coast represented the next-most economically viable movement for Powder River Basin coal, competition from Utah, Colorado, and higher Btu Wyoming coal make it unlikely that Tongue River coal would flow in this direction.

Construction of export terminals in the Pacific Northwest and the subsequent westbound rail transport of Powder River Basin coal for export would result in the most substantial changes in nonlocal (i.e., traffic outside of the of the Montana and Wyoming Powder River Basin area) coal traffic patterns relative to current conditions. While the Proposed Action would change local train traffic in the Powder River Basin, it would not substantially change the nonlocal rail traffic. In contrast, construction of export terminals in the Pacific Northwest would substantially increase rail traffic outside of the Powder River Basin. Thus, the rail traffic changes would be greater under export terminal growth than under additional Tongue River coal production. This is because there is much less coal traffic to the Pacific Northwest now, compared to coal traffic to other domestic markets east of the Powder River Basin. However, OEA predicts that changes in nonlocal rail traffic to the west would occur at the same levels whether or not the Tongue River Railroad is built. This is because under the No-Action Alternative, other Powder River Basin coal would be exported up to the maximum available terminal capacity.

1.2.9 Chapter 10. Results of Emissions Forecasts

Chapter 10 presents the modeled projections of air emissions from the combustion of coal (natural gas is included in some cases for comparison purposes). The emissions of interest are CO₂, sulfur dioxide (SO₂), and mercury.

- Carbon dioxide emissions.** OEA used IPM[®] to forecast CO₂ emissions from the combustion of Tongue River, U.S., and global coal. These emissions would be proportional to the amount of coal burned. Across all 21 scenarios, from 2018 to 2037, the average annual Tongue River coal production would be 30.6 million tons. However, because, on average, 95% of the Tongue River coal would displace other U.S. coal, the average net increase in coal combustion in the United States would be 1.4 million tons per year, averaged over all scenarios and for the years 2018 to 2037. Total U.S. coal CO₂ emissions from the incremental consumption of Tongue River coal averaged over 2018 to 2037 would range from an increase of 0.4 to 6.4 million metric tons per year and would average an increase of 2.4 million metric tons of CO₂ per year. Total U.S. coal and natural gas CO₂ emissions from the incremental consumption of Tongue River coal averaged over 2018 to 2037 would range from an increase of 0.4 to 5.0 million metric tons per year and would average an increase of 1.9 million metric tons of CO₂ per year. The CO₂ emissions increase from the consumption of Tongue River coal would be slightly offset by less natural gas consumption. Total U.S. and Pacific Basin CO₂ emissions from the incremental consumption of Tongue River coal averaged over 2018 to 2037 would range from an increase of 0.41 to 4.94 million metric tons per year and would average an increase of 1.95 million metric tons of CO₂ per year.
- Sulfur dioxide emissions.** Tongue River coal would displace coals with higher sulfur content and would result in reduced domestic SO₂ emissions for 12 of the 21 scenarios. The change in SO₂ emissions over the 21 scenarios would range from an increase of 0.4 thousand tons per year (scenario 13) to a decrease of 22.2 thousand tons per year (scenario 20). Averaged across the 21 scenarios and over the years 2018 to 2037, SO₂ emissions would decrease by 10.6 thousand tons per year or 0.6% of U.S. SO₂ emissions. In comparison, in the No-Action Alternative, national SO₂ emissions would average 1,656 thousand tons per year (2018 to 2037), ranging from 1,542 thousand tons per year (scenario 24) to 1,736 tons per year (scenario 2).
- Mercury emissions.** Domestic mercury emissions would increase in all but two scenarios as a function of the overall increase in coal consumption. For these scenarios, the average percentage increase of mercury emissions would be 0.17%. For all 21 scenarios, the change in mercury emissions would range from an increase of 45.3 pounds per year (scenario 16) to a decrease of 12.3 pounds per year (scenario 20). In comparison, in the No-Action Alternative, U.S. mercury emissions would average 13,150 pounds per year (2018 to 2037), ranging from 12,315 pounds per year (scenario 24) to 13,670 pounds per year (scenario 2). OEA found that the net changes in Pacific Basin mercury emissions related to consumption of Tongue River coal would be small

compared to total Pacific Basin mercury emissions, and would range from an increase of less than 0.01% to a decrease of less than 10%. The maximum increase in any one year would be 129 pounds (scenario 5 in 2030), and the maximum decrease in any one year would be 958 pounds (scenario 19 in 2030).

Chapter 2

Historical Powder River Basin Production and Markets

2.1 Introduction

OEA documented the historical and projected trends in Powder River Basin coal production, and the distribution, domestic and international markets, coal prices, and environmental regulations that may affect the coal market. OEA's conclusions are as follows.

- The large U.S. coal market and competition among suppliers, including competition among Powder River Basin suppliers, would affect Tongue River coal production and rail transportation.
- Anticipated growth in international coal demand and rising coal prices will increase demand for Powder River Basin coal. This demand will increase the economic feasibility of potentially induced coal production and rail transportation for Powder River Basin coal.
- Over the last 20 years, Powder River Basin coal prices have increased. Higher prices will increase the economic feasibility of potentially induced coal production and rail transportation.
- Lower natural gas prices and lower power demand caused a drop in Powder River Basin coal production and prices in 2012. Although the decrease in production was moderate and natural gas prices have since recovered, the natural gas market will continue to affect the coal market.
- President Obama's Climate Change Action Plan (June 2013) and future initiatives or regulations that address carbon dioxide (CO₂) emission controls could affect the domestic coal market.

The remainder of this chapter addresses coal production and distribution, coal markets, price variables, and the two environmental regulations that affect coal markets.

2.2 Coal Production and Distribution

2.2.1 Coal Types

As discussed in Chapter 1, *Introduction and Summary*, Tongue River coal refers to the coal from the proposed Otter Creek Mine, Poker Jim Creek–O'Dell Creek coal deposit, and Canyon Creek coal deposit, all in Montana. Powder River Basin coal, in this context, refers

to all coal produced in the Powder River Basin, including coal production that could be induced by the proposed rail line. Wyoming is the primary source of Powder River Basin coal.

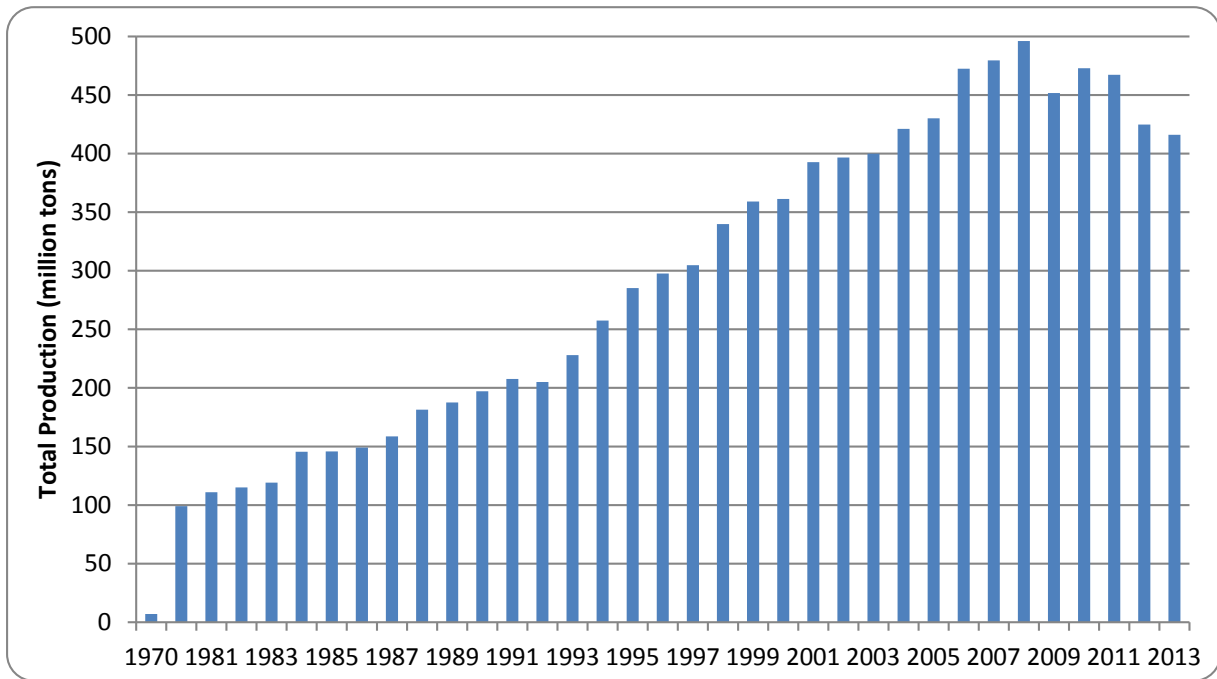
This analysis considers three additional categories of coal: coal produced elsewhere in Montana (Montana coal), coal produced in Wyoming with a heat content of 8,400 British thermal units per pound (Btu/lb) (Wyoming 8400 coal), and coal produced in Wyoming with a heat content of 8,800 Btu/lb (Wyoming 8800 coal). Section 3.2.2, *Proposed and Potentially Induced Mining Determination Factors*, provides details on the characteristics of each coal type.

2.2.2 Coal Production

The Tongue River Railroad would provide rail access to a coal-rich portion of the Powder River Basin in Montana (Figure 1-1). The Powder River Basin coalfield is already the largest source of coal in the United States, accounting for 40% of national coal production.

Since 1970, Powder River Basin coal production has increased significantly (Figure 2-1). Between 1993 and 2008, production more than doubled, from 228 million tons per year to a record high of 496 million tons per year. Between 2009 and 2011, coal production averaged 464 million tons per year, and ranged from 452 million tons in 2009 to 473 million tons in 2010 (U.S. Energy Information Administration 2013). In 2012, production decreased to 425 million tons, driven down by the lowest natural gas prices in 15 years and lower electric power demand (Mine Safety and Health Administration 2013). This trend continued in 2013 with production decreasing to 416 million tons. EIA expects total 2014 and 2015 production to meet or exceed 2013 production, but remain below 2012 production (U.S. Energy Information Administration 2014).

Figure 2-1. Historical Powder River Basin Coal Production (Montana and Wyoming)



Source: BXG Publications 1993 (1970–1982 data), Mine Safety and Health Administration 2014 (1983–2013 data).

Since 2008, Wyoming coalfields have produced about 91% of Powder River Basin coal, with the remaining 9% produced in Montana (Table 2-1). Because Wyoming produces so much more coal than Montana, it has developed a more extensive rail infrastructure. Tongue River coal production could increase the output from Montana by 50% or more.

Table 2-1. Powder River Basin Coal Production by State (million tons)

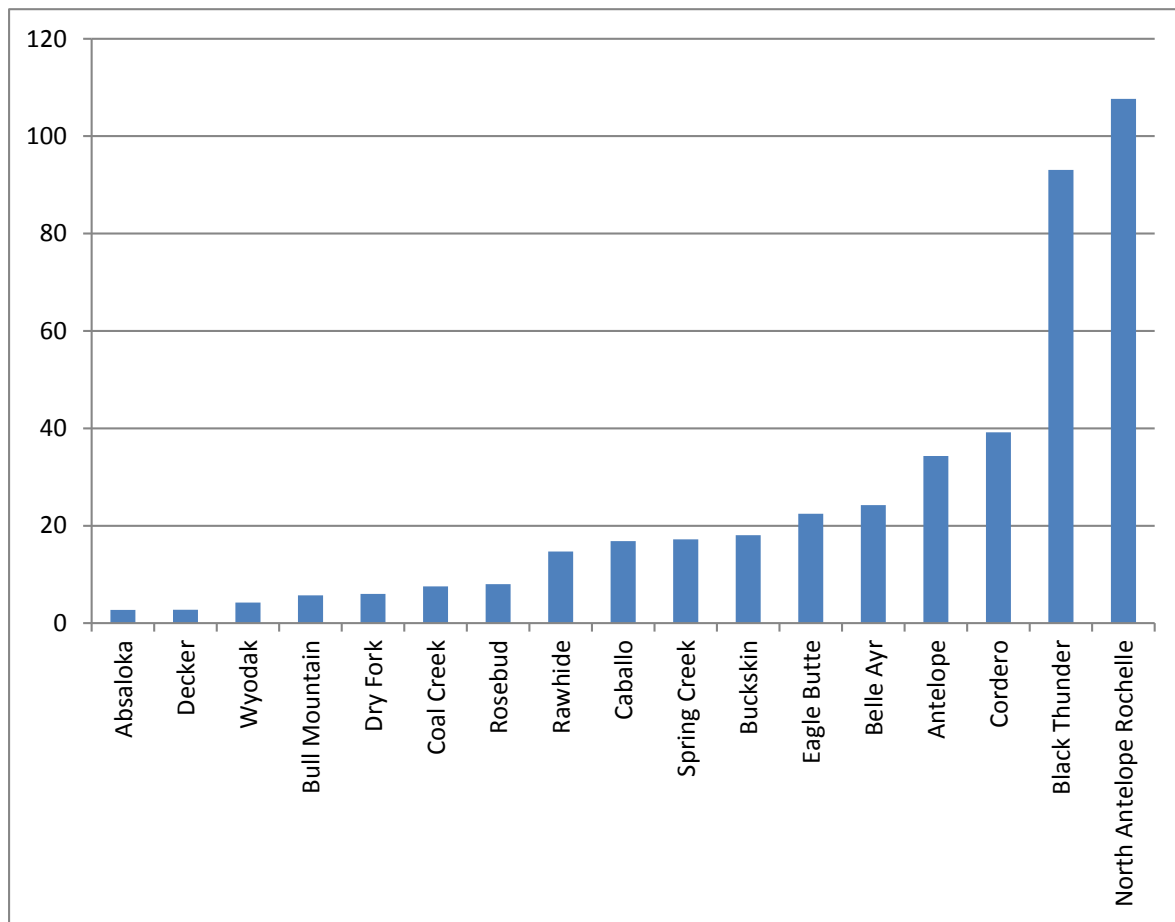
State	2008	2009	2010	2011	2012	2013	2008–2012 Average
Montana	44	38	44	41	36	42	41
Wyoming	452	414	428	426	388	374	422
Total	496	452	473	467	425	416	463

Notes:

Source: Mine Safety and Health Administration 2013

Figure 2-2 shows that only 17 mines contribute to coal production in the Powder River Basin, and all except one (Bull Mountain) are surface mines. Two mines (Black Thunder and North Antelope Rochelle) dominate production, accounting for approximately half of the region’s coal production.

Figure 2-2. Powder River Basin 2012 Production by Mine (million tons)



Source: Mine Safety and Health Administration 2013

2.2.2.1 Mine Characteristics

Powder River Basin coal is almost entirely produced using surface mining technology; there is only one deep (underground) mine in the basin.¹ Powder River Basin coal mines are large compared to other U.S. coal mines. Most Powder River Basin mines produce at least 10 million tons per year, and two (the Black Thunder and the North Antelope Rochelle Mines in Wyoming) each produce 100 million tons per year. For comparison, mines in the eastern United States produce, on average, less than 1 million tons of coal per year, with very few mines producing over 4 million tons per year. The relatively high production levels at mines in the Powder River Basin offer economies of scale that could induce additional coal mining in the region.

Mining conditions change over time. As a mine ages, more overburden must be removed to access the coal, thus increasing the cost of production. Productivity gains have counteracted, to some degree, the increased cost of overburden removal. For example, the size of the

¹ Because new underground mines are not considered economically viable, only surface mines are included in this analysis.

shovels and trucks has increased, which allows more material to be moved in the same amount of time. The most significant contributor to the cost of surface mining coal production, however, remains the overburden ratio.

2.2.3 Coal Distribution

Powder River Basin coal is subbituminous and has a lower heat content than the bituminous coal mined in the eastern United States. As discussed in Section 1.3, *Export Markets*, the lower heat content increases the transportation cost per unit of energy, and has effectively limited the historical distribution of Powder River Basin coal to domestic markets, although in recent years exports of Powder River Basin coal have been increasing.

Historically, 98% of Powder River Basin coal has been distributed to the domestic market. Powder River Basin coal generally reaches large markets in the Midwest, Texas, the southeast, and within the basin itself (U.S. Energy Information Administration 2013a). On average, from 2008 through 2012, Iowa, Illinois, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin, consumed more than 45% (208 million tons per year) of Powder River Basin coal, while Texas consumed 13% (62 million tons per year) (Table 2-2).

Table 2-2. Average Annual Deliveries of Powder River Basin Coal by Region^a

Region	Montana Coal (million tons per year)	Wyoming Coal (million tons per year)	Total (million tons per year)	Montana Coal (%)	Wyoming Coal (%)
Central United States	16.6	286.8	303.4	46	67
Mid-Atlantic	0.3	2.2	2.5	1	1
Northeast	0.2	2.3	2.5	1	1
Powder River Basin	9.6	26.2	35.8	27	6
Rockies	0.1	9.4	9.5	0	2
Southeast	0.0	25.6	25.6	0	6
Southwest	0.7	5.8	6.5	2	1
Texas	0.0	61.6	61.6	0	14
West	2.7	5.4	8.1	8	1
Exports	5.6	4.2	9.8	16	1
Total	35.8	429.5	465.3	100	100

Notes:

^a Domestic deliveries average 2008-2012 data from U.S. Energy Information Administration 923; International deliveries (exports) average 2009-2011 data from U.S. Energy Information Administration *Annual Coal Distribution Report* as 2012 data is not yet available.

Source: U.S. Energy Information Administration 2013a, 2013b

Table 2-3. Historical Powder River Basin Coal Production by Source State and Destination (million tons)^a

State	Historical Distribution	2009	2010	2011	2012	2013
Montana	Domestic Consumption ^b	36	38	33	25	30
	Exports ^{c,d}	2	6	8	11	12
	Total Production ^e	38	44	41	36	42
Wyoming	Domestic Consumption ^b	411	423	422	384	370
	Exports ^{c,d}	3	5	4	4	4
	Total Production ^e	414	428	426	388	374
Total	Domestic Consumption ^b	447	462	455	409	400
	Exports ^{c,d}	5	11	12	15	16
	Total Production ^e	452	473	467	425	416

Notes:

^a Estimated exports from Montana have grown six-fold between 2009 and 2013, causing total Powder River Basin exports to more than triple. However, exports of Powder River Basin coal remain less than 4% of total Powder River Basin coal production.

^b Total production less exports

^c U.S. Energy Information Administration 2013b. Export values estimated for 2012 and 2013.

^d Thapa pers. comm.

^e Mine Safety and Health Administration 2013

The following factors have historically limited the economic viability of exporting Powder River Basin coal compared to coal with higher heat content, thermal coal, or coking- quality coal.

- Long distances to export terminals
- Abundant international coal supply
- Relatively low international coal prices
- Relatively high shipping costs compared to international coal sources
- Lower international demand for steam coal² than for coking-quality coal

Powder River Basin coal is exported primarily through the Pacific Northwest to Asia, with a small amount exported to Europe (Table 2-4).

² *Steam coal*, also known as *thermal coal*, is coal that is burned to generate steam, which is used primarily to produce electricity. Steam coal includes both bituminous, subbituminous, and lignite coal.

Table 2-4. Powder River Basin Coal Exports by Terminal of Departure (2012)

Terminal	Destination	Coal Exports (million tons per year)
Westshore (Vancouver, BC) ^a	Asia	4.5
Ridley (Prince Rupert, BC) ^b	Asia	2.2
New Orleans and Texas Gulf Coast ^{c,d}	Asia	2.0
Duluth (Superior, WI) ^{c,d}	Europe	1.5
Total		10.2

Notes:
^a Westshore Terminals Investment Corporation 2012
^b IHS McCloskey 2013a
^c U.S. Securities and Exchange Commission 2012a
^d U.S. Securities and Exchange Commission 2012b

2.3 Coal Markets

2.3.1 Domestic

As described in Section 2.2.3, *Coal Distribution*, most of the Powder River Basin coal is distributed to markets in the Midwest. The coal is burned in numerous power plants to meet demand for electricity in the region. Many of the coal plants in the Midwest were designed specifically to burn Powder River Basin coal, rather than higher-heat bituminous coal mined in the Appalachian region or the Illinois Basin. This is because, at the time the coal plants were constructed, coal was the least cost fuel source for producing electric power. On a dollar-per-million-Btu (\$/MMBtu) basis, coal is still one of the least expensive options for electric generation in the Midwest, and much of the local electric power requirements are met using coal. In the future, it is likely that many power plants in the Midwest will continue to burn Powder River Basin coal. Because subbituminous coal from the Powder River Basin generally contains lower levels of sulfur and other pollutants than bituminous coal from other regions, stricter environmental regulations tend to favor power plants that burn Powder River Basin coal.

2.3.2 International Markets

As described in Section 2.2.3, *Coal Distribution*, only about 2% of Powder River Basin coal is exported to international markets. The top five coal-importing countries (Japan, China, South Korea, India, and Taiwan) are located in Asia and together they account for 64% of total coal imports. In contrast, coal exports to Europe declined between 2007 and 2010 because of the global recession, European economic conditions, and public opposition toward the continued use of coal in Europe (Table 2-5). Coal demand in the Atlantic Basin increased in 2011 due to high natural gas prices in Europe.

Some of the top importers rely heavily on coal imports to meet their consumption. For example, Japan, South Korea, and Taiwan import all of their coal, whereas China and India have significant domestic production and could reduce imports if coal prices increase.

Table 2-5. Top International Coal Importers in Million Tons (2011)

Rank	Country	Total Coal Import	Total Coal Consumption	Import (%) of Consumption
1	Japan	194.1	192.9	100.6
2	China	192.5	3,826.9	5.0
3	Korea, South	138.2	139.5	99.1
4	India	86.8	721.4	12.0
5	Taiwan	73.5	73.3	100.3
6	Germany	49.3	256.7	19.2
7	United Kingdom	35.9	54.9	65.4
8	Russia	27.3	256.7	10.6
9	Netherlands	27.2	13.1	207.9
10	Turkey	26.4	112.5	23.5
11	Italy	25.7	25.3	101.9
12	Malaysia	23.7	26.5	89.5
13	Brazil	21.8	27.6	79.2
Total Coal Imports		922.3		

Notes:

Sources: Yang and Cui 2012, U.S. Energy Information Administration 2011

The top exporters of coal are Indonesia and Australia, together accounting for 48% of the total coal exports in 2011 (Table 2-6). Australian companies and port owners propose to construct and expand export terminals, which would triple export capacity from 490 to 1,420 million tons per year (Yang and Cui 2012).

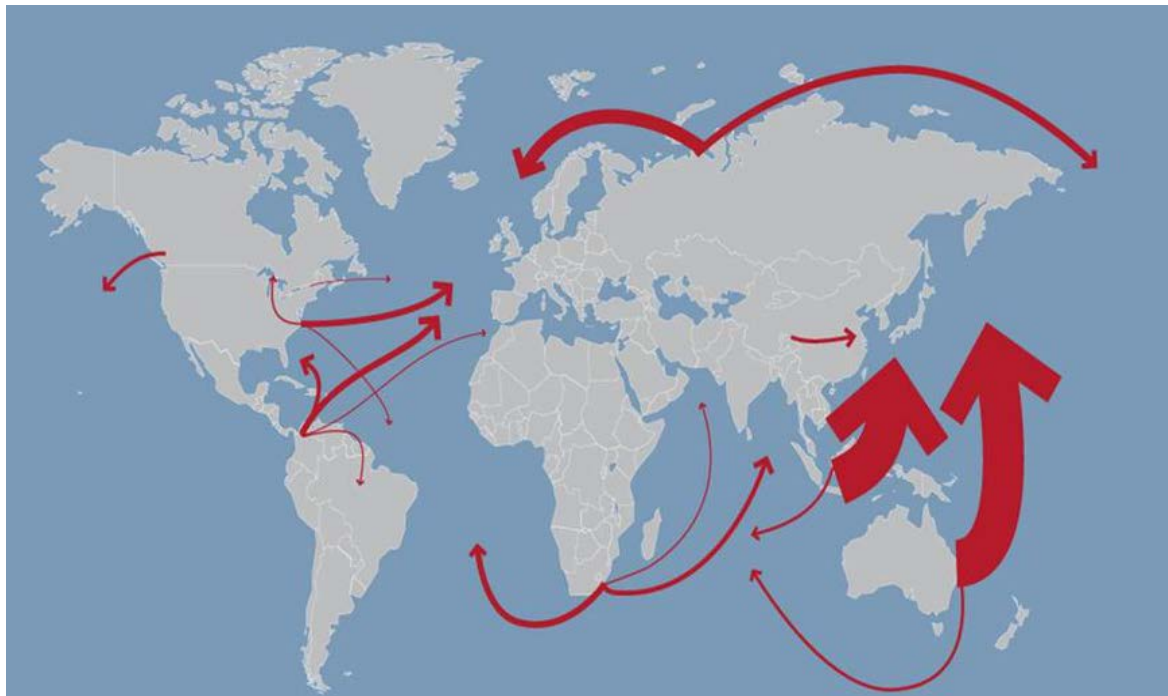
Table 2-6. Top International Coal Exporters in Million Tons (2011)

Rank	Country	Total Coal Export	Total Coal Production	Export (%) of Production
1	Indonesia	341.1	414.8	82.2
2	Australia	313.6	456.7	68.7
3	Russia	138.6	368.0	37.7
4	United States	108.2	1,094.3	9.9
5	Colombia	89.0	94.6	94.2
6	Africa	80.4	284.3	28.3
7	South Africa	79.0	279.0	28.3
8	Kazakhstan	37.6	128.6	29.2
9	Canada	37.6	74.0	50.8
10	Vietnam	26.9	49.1	54.9
11	Mongolia	24.4	34.6	70.6
12	China	18.2	3,844.9	0.5
13	Poland	14.8	152.6	9.7
Total Coal Exports		1,309.5		

Notes:
Sources: Yang and Cui 2012, U.S. Energy Information Administration 2010

In summary, the largest markets in the Pacific Basin are served primarily by the largest exporters in the Pacific Basin, Australia and Indonesia (Figure 2-3). Recent Pacific Basin coal trade is comparable to the flows presented for 2009. While the Pacific Basin market is expected to grow, so will the competition between a few large suppliers.

Figure 2-3. Indonesia and Australia Dominate Pacific Basin Coal Markets



Source: Alpha Natural Resources 2010

While Japan has historically been the largest importer of coal worldwide, the Indian and Chinese economies are projected to grow, adding to the demand for energy resources in the Indo-Pacific region. Coal is expected to be the fuel of choice to meet burgeoning demand. India and China alone have proposed construction of coal-fired power plants to produce nearly 1,100 gigawatts of additional power (Yang and Cui 2012). This proposed capacity is more than three times the total U.S. installed coal capacity of about 300 gigawatts. Japan, South Korea, and Taiwan lack significant domestic thermal coal reserves and have been key importers in the Pacific Basin steam coal import market. Both India and China will likely continue or increase their consumption of coal going forward. The following sections address market conditions in the top two coal-importing nations, which are expected to remain the top importing countries for the next 10 years: Japan and China. The next three top importers—South Korea, India, and Taiwan—are expected to have increasing imports, with South Korea and Taiwan increasing slowly, while coal imports to India are expected to grow more rapidly as large amounts of new capacity comes online.

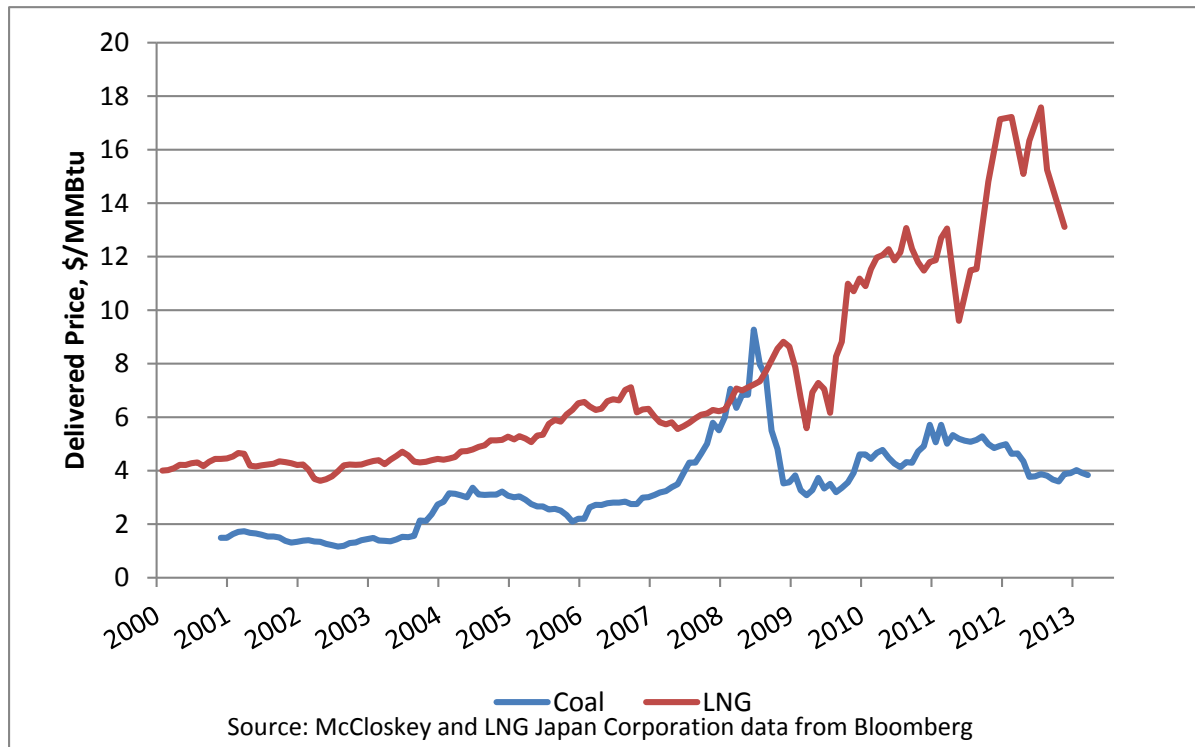
2.3.2.1 Japan

Japan has historically been the largest coal importer worldwide, importing an average of 193 million tons per year between 2000 and 2011 (U.S. Energy Information Administration 2011a). Without domestic steam coal resources, Japan relies heavily on imports to satisfy domestic coal demands. Several factors may drive an increase in Japan's coal consumption and imports in the future.

- **Uncertain future for nuclear energy.** The earthquake and tidal wave of March 2011 caused cataclysmic damage at the Fukushima nuclear power plant, precipitating the shutdown of 48 of Japan's 50 nuclear reactors, leaving only two reactors at the Oi nuclear plant in operation (Westlake 2012). Nuclear energy had previously supplied about 30% of the country's electricity needs, a percentage that, prior to the damage, had been expected to increase to 40% by 2017 and 50% by 2030 (World Nuclear Association 2013). Ten of the idled reactors may be reopened; however, with nuclear reactor operation uncertain, coal and natural gas consumption are likely to increase to meet demand.
- **Relative expense of liquefied natural gas.** Coal has historically been significantly cheaper than liquefied natural gas at generally about half price per unit of energy (Figure 2-4). Much of the recent rush to build domestic liquefied natural gas export terminals is targeted at exporting gas to Asian countries such as Japan (the world's largest liquefied natural gas importer) to take advantage of the significantly higher natural gas prices in Asia.
- **Renewed government commitment to coal energy.** After withholding approval of all but two proposed coal-fired power plants since 2006, Japan's Ministry of Environment recently lifted a virtual ban on construction of new coal plants, provided they are equipped with the cleanest and best technologies. This development is motivated by the

economic need to diversify energy resources rather than by environmental or safety considerations (Iwata 2013).

Figure 2-4. Delivered Coal versus Natural Gas Prices to Japan (\$/MMBtu)

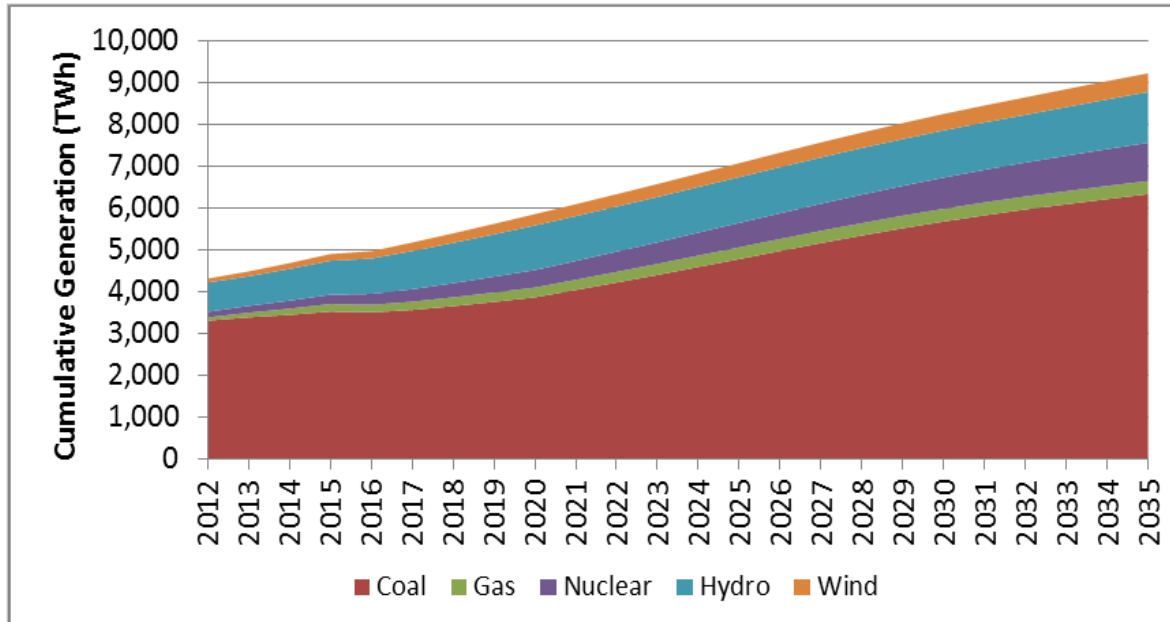


2.3.2.2 China

China is the world's largest coal producer and consumer. China's coal demand, driven by power generation and industrial uses, increased by an average of 9% annually from 2000 to 2010. For comparison, demand outside of China increased at an average of only 1% per year (U.S. Energy Information Administration 2013b). As of 2011, China's coal consumption accounted for 47% of global coal consumption at about 3.8 billion tons annually—almost as much as the entire rest of the world combined (U.S. Energy Information Administration 2013d). China's demand for coal is expected to grow in the near future. Although current policy changes in China will reduce the growth rate of coal consumption, the absolute amount of coal consumed will continue to increase. A U.S. Environmental Protection Agency (USEPA) projection of China's power generation shows that coal will produce 67 to 75% of the nation's electrical energy from 2012 to 2035 (Figure 2-5). Coal-fired electric power generation is expected to increase by 87% compared to current 2013 levels (U.S. Energy Information Administration 2013d). To meet growing demand, China is considering proposals for 363 new coal-fired power plant projects, which would increase installed capacity to 558 gigawatts (Yang and Cui 2012). For comparison, the total capacity for all coal-fired power plants in the United States is currently about 325 gigawatts, from which some 42 gigawatts are expected to be retired by the end of 2013 (SNL Energy 2013). With

its vast domestic coal resources, China has historically been a coal exporter. However, China's coal imports exceeded exports for the first time in 2009 (Figure 2-6). In 2011, China imported nearly 200 million tons of coal, or approximately 5% of total Chinese coal consumption.³ The increase in imports has been rapid and dramatic, and suggests a strong market in the Pacific Basin.

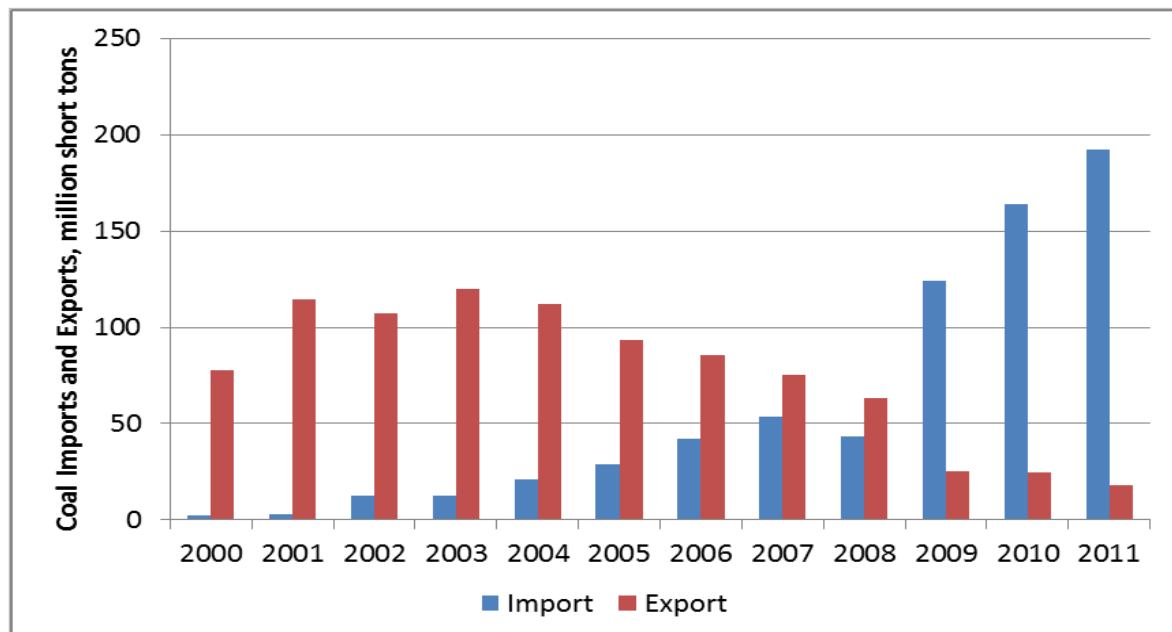
Figure 2-5. China's Projected Cumulative Power Generation by Type



Source: U.S. Energy Information Administration 2011b

³ For reference, 200 million tons is about 45% of recent annual coal production from the Powder River Basin, and about 10 times the permitted annual production of 20 million tons from the Otter Creek Mine.

Figure 2-6. China's Coal Imports and Exports, 2000–2011 (million tons)



Source: U.S. Energy Information Administration 2011a

In addition to growing demand, several factors may increase China's reliance on imports in the future (Hook 2011).

- Transportation bottlenecks.** Mining activity in China has shifted farther north and west, away from the south and eastern coastal cities where many coal-fired power plants are located and the demand for electricity is greatest. The coal must be transported from remote northwest locations, where there is no demand for electricity, to the northeast ports, where it is shipped to the southern ports for domestic consumption. With such a long route from mine to plant, transportation of Chinese coal is a bottleneck, although massive rail infrastructure expansions are planned and under construction. The transportation bottlenecks may be reduced in the future.
- Mine safety.** China produces coal primarily from underground coal mines. The methane concentrations in China's underground mines are responsible for a high number of fatalities, relative to fatalities in U.S. underground mines on a per ton basis. In 2012, the overall death rate in China's coal mines was 0.374 deaths per million tons of coal production. In contrast, the death rate in the United States was around 0.035 deaths per million tons of coal production. By increasing coal imports, especially coal produced from surface mines, China expects to lower overall mining fatalities per ton of coal consumed (China Labour Bulletin 2013, Mine Safety and Health Administration 2014).
- Mine consolidation.** The Chinese government has been consolidating small, private mines into a few large state-owned mines. Initially, consolidation causes coal production to fall dramatically as mines are closed temporarily to retrofit them with additional safety measures (Hook 2011).

- **Economic viability.** The costs of developing a transportation network for coal, as well as costs for improving mine safety and reducing environmental impacts, may make importing coal more cost-effective than mining coal in China.

2.4 Price Variables

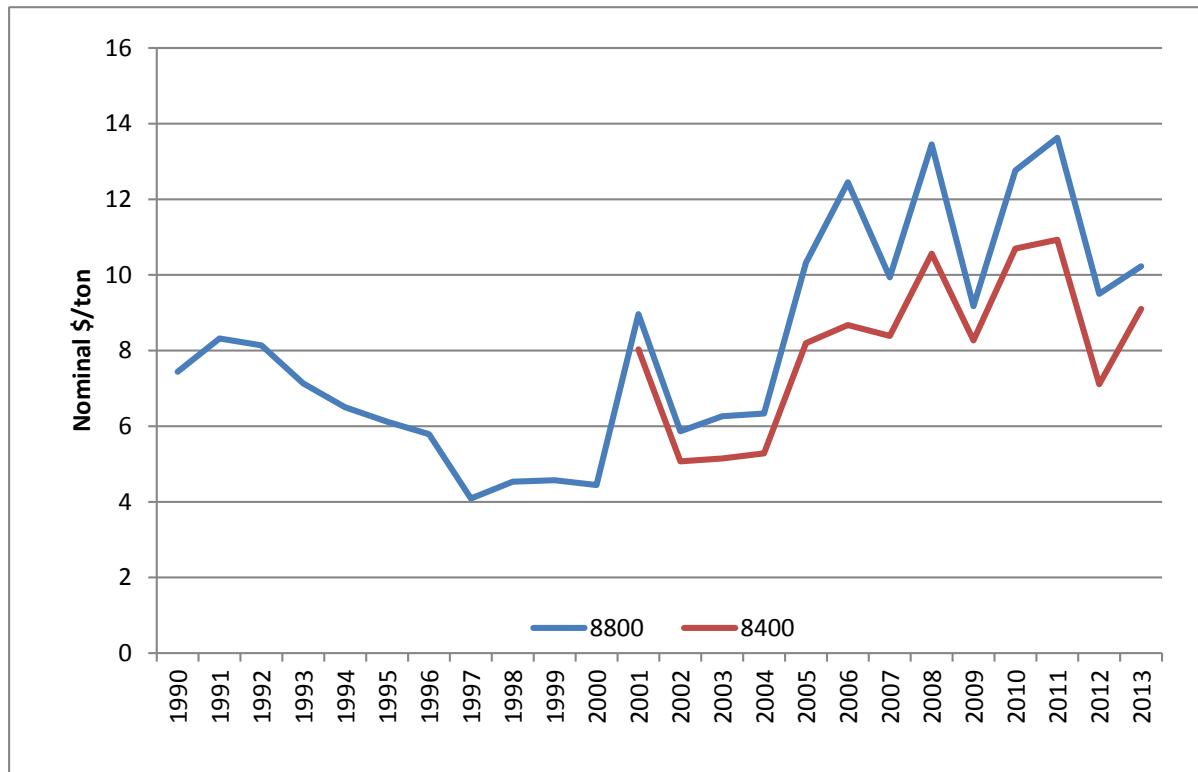
2.4.1 Coal Prices at the Mine

Two points are relevant when reviewing Powder River Basin coal prices.

- **Price relative to heat content.** There are two commonly traded types of coal, coal rated for 8,400 Btu/lb (16.8 MMBtu/ton) and coal rated for 8,800 Btu/lb (17.6 MMBtu/ton). Lower heat content increases transportation cost per unit of energy delivered. Coals with a lower heat content are priced lower on a dollar-per-ton basis compared to coal with a higher heat content.
- **Minemouth prices.** The minemouth prices, or prices at the mine, of Powder River Basin coal are low compared to other U.S. minemouth coal prices. The low overburden ratios and the thick coal seams in the region result in relatively low production costs.

Although minemouth prices for Powder River Basin coal may fluctuate by up to 30% each year, they have steadily increased since the late 1990s (Figure 2-7). Prices have been driven up by increased demand and increased costs of production. Wyoming 8800 coal averaged \$4 per ton in 1997, increasing to \$10.25 per ton in 2012. Wyoming 8800 coal prices have increased in 2014 to \$12.60 per ton.

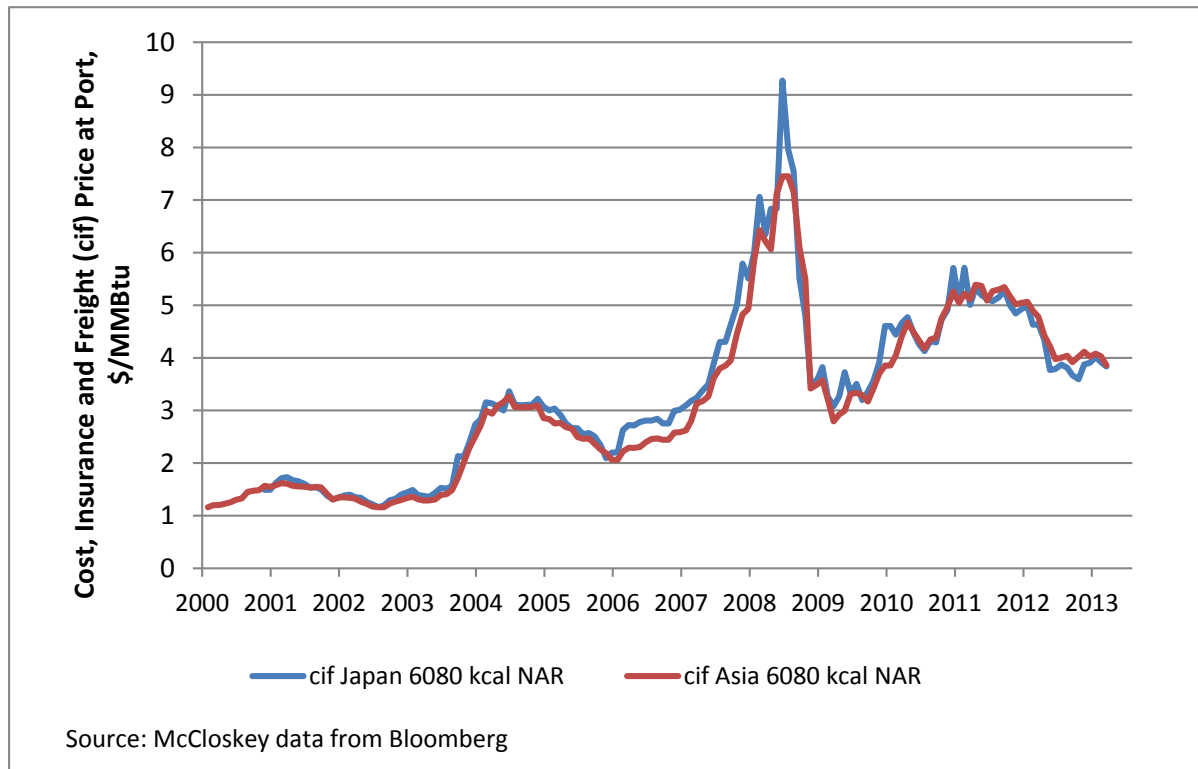
Figure 2-7. Powder River Basin Coal Prices (Nominal \$/ton)



2.4.2 Delivered Coal Prices to the Pacific Basin

Delivered coal prices to the Pacific Basin include the costs of coal, freight, and insurance. These prices are summarized using McCloskey's Japan and Asia index benchmarks (IHS McCloskey 2013b), which show delivered prices at the terminal of delivery. Prices ranged from \$3.50 to \$5.50/MMBtu from 2009 to 2013 (Figure 2-8). Because these prices are expressed as price per energy unit (\$/MMBtu) they account for coal with different heat content. Consequently, delivered prices in Asia in the range of \$4.50/MMBtu suggest that Powder River Basin coal would be cost-competitive, if shipped through the Pacific Northwest to Japan or other Pacific Basin countries (Chapter 4, *Proposed Coal Export Terminals and Expansions*, and Chapter 8, *Coal Production and Transportation Modeling Results*).

Figure 2-8. Pacific Basin Steam Coal Prices, Japan, and Asia

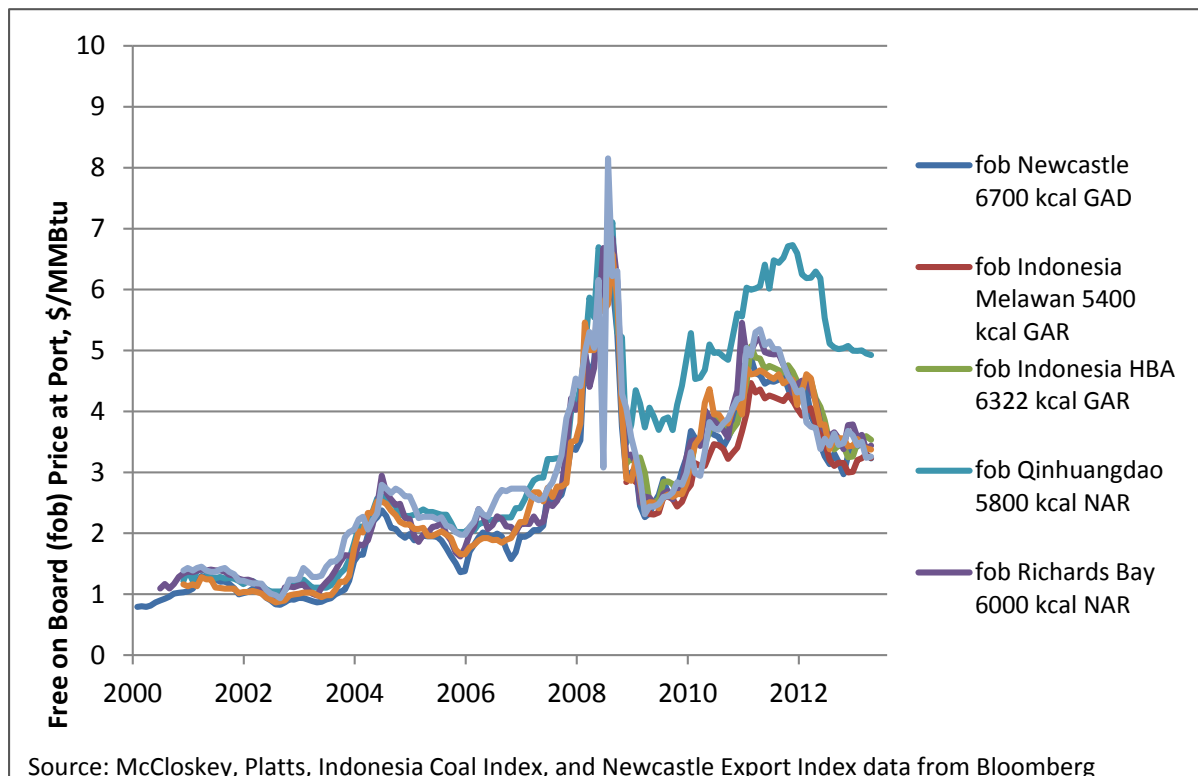


2.4.3 Free On Board Terminal Prices in the Pacific Basin

Free on board (FOB) terminal prices refer to the aggregate price of the coal, insurance, loading, transportation to the terminal, and documentation costs, typically paid by the seller. Figure 2-9 shows FOB prices at the supply country's terminal, expressed as price per energy unit (\$/MMBtu) to account for coal with different heat content. Key players in the Pacific Basin steam coal export market include Australia (Newcastle), Indonesia (Melawan and HBA), China (Qinhuangdao), South Africa (Richards Bay), and Russia (Vostochny and Baltic). OEA did not adjust the prices in Figure 2-9 for the coal moisture content because coals are reported as gross air-dried, gross as received, and net as received.⁴

⁴ Definitions and conversions can be found at World Coal Association, Coal Conversion Statistics (<http://www.worldcoal.org/resources/coal-statistics/coal-conversion-statistics>).

Figure 2-9. Historical Pacific Basin Free On Board Steam Coal Prices



Trends in FOB costs are relatively consistent across supply ports, with the exception of China's Qinhuangdao prices, which were noticeably higher from 2009 to 2013. This gap in prices further illustrates demand for lower-cost coal imports in China. Powder River Basin coal shipped through Vancouver, British Columbia or other Pacific Northwest ports has an FOB cost of close to \$3.00/MMBtu, making it cost-competitive in the Pacific Basin at 2013 coal prices.

2.4.4 Exchange Rate Uncertainties

Australia and Indonesia are currently the two largest suppliers of steam coal in the world and Japan and China are the two largest importers (Tables 2-5 and 2-6). Exchange rate variables can greatly affect prices and trade in this global market. A historical 10-year snapshot of exchange rates between the U.S. dollar (USD) and the Australian Dollar (AUD), the Indonesian Rupiah (IDR), the Japanese Yen (JPY), and the Chinese yuan (CNY) are exhibited in Figures 2-10 through 2-13 (OANDA 2013).

Barring a few upward spikes, the USD/AUD exchange rate has been generally trending downward over the last 10 years. The USD/IDR exchange rate has been volatile over the last ten years, but is showing signs of increasing in the last year. The USD/JPY exchange rate has been relatively constant with a slight downward trend over the last 10 years; however, it is showing signs of increasing in the last year. The USD/CNY exchange rate has decreased

significantly over the last 10 years, primarily because of Chinese monetary policy (OANDA 2013).

Overall, the 10-year historical trend favors increased competitiveness for Powder River Basin coal, because declining exchange rates make competing coals relatively more expensive. If this trend continues in the future, the U.S. cost advantage would grow relative to China and Australia, and would decline modestly for Indonesia. As discussed in Chapters 7, *Scenarios*, Chapter 8, *Coal Production and Transportation Modeling Results*, and Chapter 10, *Results of Emissions Forecasts*, OEA conducted the modeling in U.S. dollars, which assumes constant future exchange rates at current levels. Thus, the model could understate the competitiveness of U.S. coal if the current exchange rate trends continue.

Figure 2-10. 10-year Historical U.S./Australia Exchange Rate



Source: OANDA 2013

Figure 2-11. 10-year Historical U.S./Indonesia Exchange Rate



Source: OANDA 2013

Figure 2-12. 10-Year Historical U.S./Japan Exchange Rate



Source: OANDA 2013

Figure 2-13. 10-Year Historical U.S./China Exchange Rate



Source: OANDA 2013

2.4.5 Natural Gas Prices and Power Demand

Historical coal-fired electric power generation has been cheaper and more abundant (in terms of overall contribution to the domestic electric power sector) than natural gas-fired electric power generation. In 2012, however, domestic natural gas prices were lower than any time since 2000 (Table 2-7). This, in turn, lowered domestic coal demand and prices. The low natural gas prices in 2012 reflected unusually warm winter conditions (lower demand for electric heating) and increased shale gas production (excess supply). Since then, natural gas prices have recovered somewhat, but not quite to 2009 to 2011 levels. Henry Hub⁵ natural gas prices were \$3.87 per million MMBtu as of July 18, 2013.

⁵ *Henry Hub* refers to a major distribution hub on a major natural gas pipeline that connects with multiple interstate and intrastate pipelines. The name also refers to the pricing point for natural gas futures contracts and swaps traded on the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE).

Table 2-7. Historical Henry Hub Natural Gas Prices (\$/MMBtu)

Year	Real 2012 Dollars (\$)
2000	5.61
2001	5.05
2002	4.23
2003	6.75
2004	7.06
2005	10.29
2006	7.54
2007	7.59
2008	9.48
2009	4.16
2010	4.56
2011	4.08
2012	2.74
2013	3.65
Average	6.09

Notes:
Source: Bloomberg 2013
\$/MMBtu = dollars per million British thermal units

Demand for electric power decreased in 2012 (Table 2-8), further suppressing the domestic coal market. Lower demand was driven by slower economic growth and increased energy efficiency.

Table 2-8. U.S. Electric Power Sales (TWh)

Year	Amount	Annual Growth (%)
2001	3,394	NA
2002	3,465	2.09
2003	3,494	0.82
2004	3,547	1.54
2005	3,661	3.20
2006	3,670	0.24
2007	3,765	2.58
2008	3,733	-0.84
2009	3,597	-3.65
2010	3,754	4.38
2011	3,750	-0.12
2012	3,687	-1.68

Notes:
Source: U.S. Energy Information Administration 2012
TWh = terawatt hours

When expressed as price per MMBtu in 2012 dollars, the minemouth price of 8800 coal more than doubled between 1998 and 2011, from \$0.34/MMBtu to \$0.78/MMBtu. Nevertheless, coal remains economically competitive with other energy sources on a price per unit energy

basis. For example, Henry Hub natural gas prices in 2011 were approximately \$4/MMBtu. Even at its historic low of \$2.75/MMBtu in 2012, the price of natural gas was well above minemouth prices per unit of energy. However, a direct comparison of the minemouth price of coal for Powder River Basin coal and the Henry Hub prices for natural gas (per unit of energy) is somewhat misleading. Because transportation costs are significant, the delivered price of Powder River Basin coal may be several times higher than the minemouth price.

The delivered price of natural gas, on the other hand, may be only slightly higher than the Henry Hub prices per unit of energy. Overall, the delivered cost of Powder River Basin coal is generally lower than other sources of fossil energy per unit of energy delivered, making Powder River Basin coal less susceptible than other coals to changes in market dynamics.

2.5 U.S. Environmental Regulations

Two major environmental regulations affect coal markets the Federal Mercury and Air Toxics Standard and the CO₂ emissions regulations.

2.5.1 Federal Mercury and Air Toxics Standard

Emitters (coal-fired power plants) must comply with these standards by 2015, with the possibility of a 1-year extension. The standards generally mandate plant-specific emission controls, and have contributed to the retirement of existing coal plants. As of early 2013, nearly 42 gigawatts of coal capacity have been designated for retirement or conversion to alternative fuels (SNL Energy 2013). This equates to approximately 13% of the coal-fired power plant generating capacity in the United States.

2.5.2 CO₂ Emissions Regulations

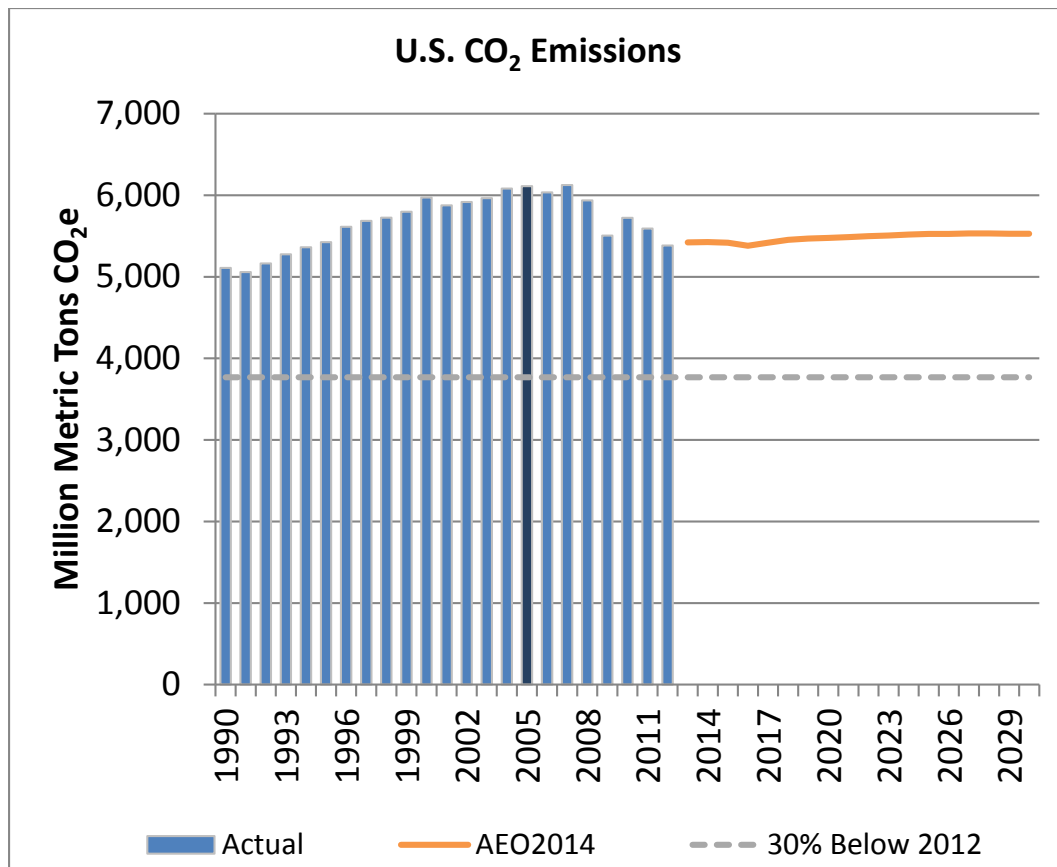
On June 25, 2013, President Obama released his plan to achieve a 17% reduction in U.S. greenhouse gas emissions below 2005 levels by 2020. With respect to CO₂ emissions from power plants, the president will complete or initiate action on emissions from existing and proposed fossil fuel-fired generators through USEPA regulation under the Clean Air Act. USEPA released a revised proposal to regulate new fossil fuel-fired generators carbon dioxide emission sources in 2013, and anticipates a final regulation for new sources by January 2015. USEPA released a proposed rule to reduce emissions at existing sources on June 2, 2014, with the final rule due in June 2015. The proposed rule is designed to reduce CO₂ emissions by 30% by 2030 from a 2012 baseline. The reductions will be obtained through a variety of measures that include reductions at and retirements of fossil-fired power plants.

The states will respond to the new regulations with state plans (also known as Section 111(d) plans) to set standards and achieve compliance with those regulations. USEPA will review the state plans and approve them or require changes (or impose a federal plan). Potential

approaches under state plans range from efficiency improvements to state-based emissions trading programs.

USEPA will regulate existing generators because they are responsible for just over 40% of U.S. CO₂ emissions and are easily identifiable point sources. Emissions have decreased since 2007 because of the recession, slow recovery, and the low price of natural gas, which emits less CO₂ than coal for the same electrical output (Figure 2-14).

Figure 2-14. U.S. Carbon Dioxide Emissions from Fossil-Fuel Energy Sources⁶



The president's pledge covers five other greenhouse gases, but CO₂ accounts for the most quantity and drives the trend for total greenhouse gas emissions. In the absence of further federal regulation, CO₂ emissions will likely increase slowly through 2020, but will remain within 3% of the 2012 levels by 2030 (U.S. Energy Information Administration 2013e).

⁶ CO₂ emissions are expressed in terms of carbon dioxide equivalency (CO₂e), which is the amount of CO₂ that would have the same global warming potential over a specified timescale as a specified mixture of greenhouse gases.

3.1 Introduction

OEA analyzed the coal production and transportation that construction of the proposed rail line could induce beyond the proposed Otter Creek Mine. The analysis incorporates the proposed production and transportation of 20 million tons per year of coal from Tract 2 of Otter Creek Mine, which is the only mine in the project area that is currently proposed for permitting and development. Depending on market conditions at the end of 20 years, Arch Coal may develop Tract 3 (years 18 to 41) and then Tract 1 (years 40 to 55) (Montana Department of Environmental Quality 2012). OEA's analysis is limited to 20 years because market conditions beyond that time are not reasonably foreseeable. The analysis also assesses potential coal production from two potentially induced mines, one at the Poker Jim Creek–O'Dell Creek deposit located in and around the previously planned Montco Mine, and one at the Canyon Creek deposit located south of the Northern Cheyenne Reservation on the west side of the Tongue River (Figure 1-1). These deposits represent some of the highest quality, strippable coal reserves in the Tongue River area. OEA examined other coal deposits in the area but eliminated them from further study because of factors such as a high overburden ratio, a low heat content, a low amount of strippable reserves, or a location of over 15 miles from the proposed rail line.

The purpose of this analysis is to estimate and analyze rail traffic levels that could result from the development of Otter Creek Mine and other potentially induced mines. Accordingly, OEA examined several levels of coal production, ranging from a low of 20 million tons per year from the proposed Otter Creek Mine only (Tongue River Railroad Company 2013a) to middle and high production ranges from both the Otter Creek Mine and other deposits.

This chapter comprises a coal deposit analysis, a description of marketable coal production scenarios, and an overview of the previous proposed actions for the Tongue River Railroad.

3.2 Coal Deposit Analysis

OEA examined potentially induced mines in the southeastern portion of the Powder River Basin in Montana. OEA selected this analysis area based on information received from TRRC and other available data. TRRC stated that its analysis includes any high-quality coal deposits in the Ashland area with the potential to be developed (Tongue River Railroad Company 2013b). OEA's analysis also responds to public comments about a potential increase in coal volume shipments due to potentially induced mining.

The U.S. Department of the Interior, Bureau of Land Management (BLM), the State of Montana, and private landowners (U.S. Geological Survey 2013) hold the mineral rights to Montana Powder River Basin coal. Mineral right ownership and surface owner consent are important components of the BLM's coal lease application process (43 Code of Federal Regulations [C.F.R.] § 3420.1). OEA focused on state and BLM lands because these lands have established leasing programs and do not require gaining surface owner consent. Additionally, the majority of coal leases in Montana come from either the State of Montana or BLM. OEA included some private landowners even though they do not typically own both the surface and mineral rights.

3.2.1 Project Area Coal Deposits

OEA identified 32 coal deposits in southeastern Montana (Figure 3-1 and Table 3-1) based on the work of Matson and Blumer (1973). This report, which describes both *areas* and *deposits* that may contain multiple coalbeds, provides a useful framework for assessing additional coal mining that may be induced by construction of the Tongue River Railroad. Although prepared in 1973, other regional studies continue to use this coal data. For example, more recent publications on the quality of Powder River Basin coal, such as the U.S. Geological Survey 1625-A papers (1999), still use data presented in the Matson and Blumer 1973 report. After a thorough literature review of information on area coal deposits, OEA determined that there were no other comparable reports that contained the same information and covered the same area.

After identifying the coal deposits, OEA conducted an in-depth screening to evaluate and compare these coal deposits. OEA eliminated the coal deposits that were determined to be economically unviable for future development from further study (Section 3.2.2, *Proposed and Potentially Induced Mining Determination Factors*).

3.2.2 Proposed and Potentially Induced Mining Determination Factors

OEA prepared a summary of potentially minable coal based on the coal deposit information presented in the Matson and Blumer 1973 report (Table 3-2). The Norwest 2006 report, prepared for the Otter Creek Mine permit application, provided data on the Otter Creek Mine coal quality based on recent bore-hole drillings and coal exploration. The relevant summary data include factors such as the size of strippable coal reserves, overburden ratio, the distance of the deposit relative to the proposed rail line, average heat content, average sulfur content, general area topography, and ash content. OEA identified which of these factors were most likely to affect the potential for induced mining and assigned weighting factors and appropriate metrics to each. OEA used these factors, and others, such as mineral rights and land use restrictions, to evaluate the potential for induced mining.

Figure 3-1. Coal Deposits in Southeastern Montana

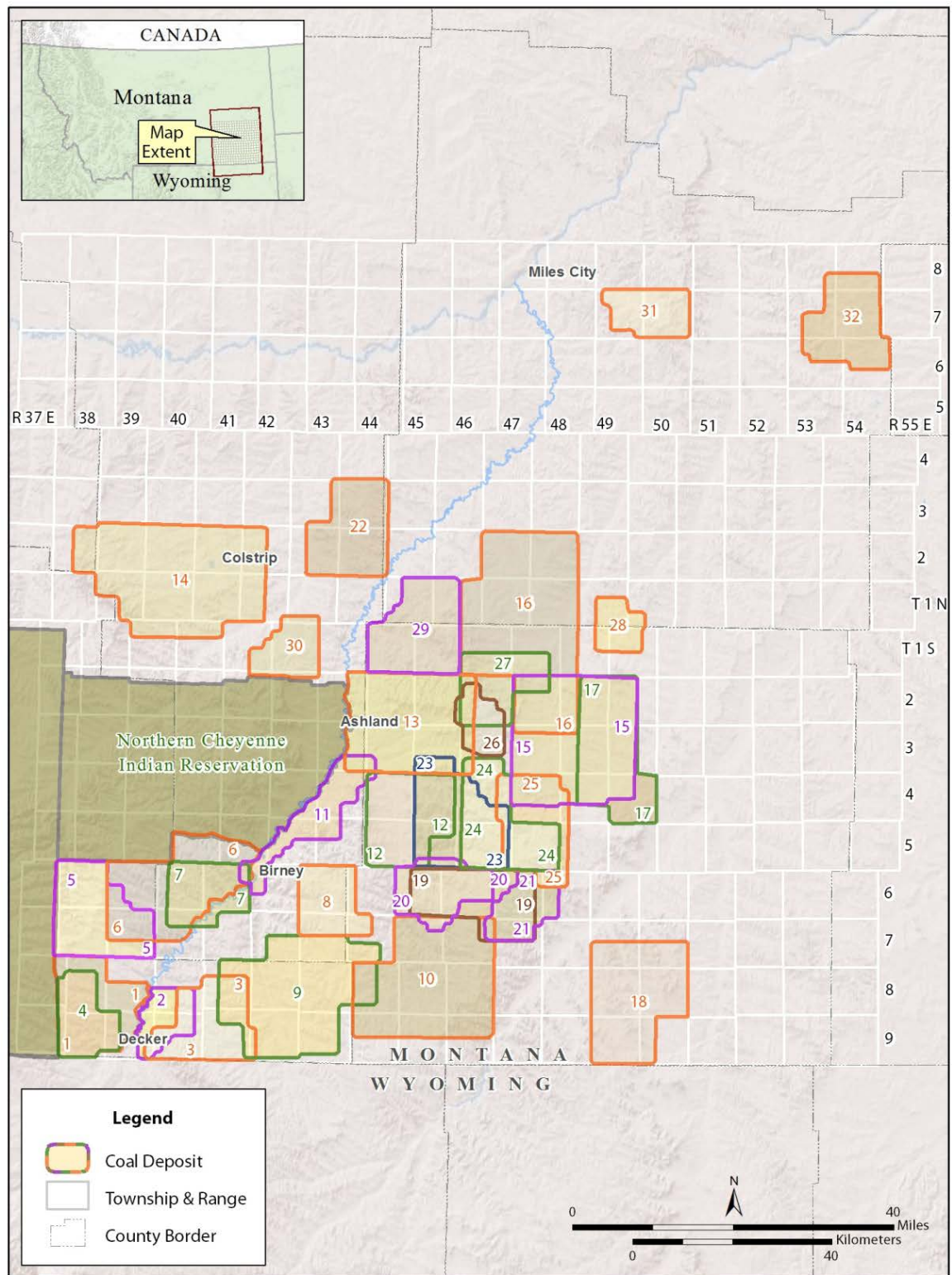


Table 3-1. Coal Deposits in Southeastern Montana

Coal Deposit	Map Number	Reserves (million tons)	Acreage ¹
Decker	1	2,239.99	25,523
Deer Creek	2	495.65	14,214
Roland	3	218.04	12,076
Squirrel Creek	4	133.41	6,208
Kirby	5	1,524.56	33,189
Canyon Creek	6	1,950.11	25,926
Birney	7	180.55	6,969
Poker Jim Lookout	8	872.65	19,609
Hanging Woman Creek	9	2,704.25	74,201
West Moorhead	10	1,971.42	62,623
Poker Jim Creek–O'Dell Creek	11	938.07	15,077
Otter Creek	12	2,075.55	25,791
Ashland	13	3,053.69	47,462
Colstrip	14	1,439.26	33,379
Pumpkin Creek	15	2,426.50	45,695
Foster Creek	16	1,427.90	69,707
Broadus	17	739.82	18,429
East Moorhead	18	525.21	15,559
Diamond Butte	19	418.02	21,363
Goodspeed Butte	20	628.95	13,446
Fire Gulch	21	336.69	8,486
Sweeney Creek–Snyder Creek	22	326.33	10,921
Yager Butte	23	1,175.86	26,924
	23	312.02	14,507
Threemile Butte	24	225.40	13,836
Sonnette	25	683.23	18,694
Home Creek Butte	26	217.21	4,851
Little Pumpkin Creek	27	215.83	8,534
Sand Creek	28	267.34	5,952
Beaver Creek–Liscom Creek	29	627.49	25,926
Greenleaf Creek–Miller Creek	30	453.71	14,918
Pine Hills	31	193.87	6,022
Knowlton	32	867.82	24,061
Notes:			
Source: Matson and Blumer 1973			

¹ Acreage amounts are based on coal deposit U.S. Geological Survey information from 1973 and are different from estimated acreage amounts in Chapter 18, Cumulative Impacts, and Appendix U, Cumulative Impacts, due to approximate mining locations mapped using GIS.

Table 3-2. Coal Resources in the Montana Powder River Basin and Potential for Induced Mining

Key Factors Affecting Potentially Induced Coal Mining																	
Factor					Metrics					Scoring			Weighting Factor (%)				
Overburden Ratio					1-3; >3-6; >6					3, 2, 1			40				
Distance to Proposed rail line (miles)					0-5; >5-10; >10; >15					3, 2, 1, 0 (exclude)			10				
Average Heat Content (Btu/lb)					≥8,500; 8,499-8,001; ≤8,000					3, 2, 0 (exclude)			25				
Sulfur Content (%)					<0.25; 0.25-0.35; >0.35					3, 2, 1			5				
Coal Production (million tons/year)					>50; 20-50; <20					3, 2, 0 (exclude)			20				
													100				

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
Squirrel Creek	Roland	133	6,208	7	7,021-9,114	0.34	0.8	2.89	5.515	Near WY border, relatively flat, also along riverbed	7	7	Decker	2	2	3	2	0	2.20
Roland	Roland	218	12,076	11	7,021-9,114	0.39	0.8	4.79	9.251	Near WY border, relatively flat	6	10	Decker	2	1	2	2	0	1.75
Kirby	Anderson	217	5,655	11	7,277-8,864	0.65	1.5	3.51	4.295	Mixed terrain of a flat valley, rolling hills, and steep mountains.	15	23	Decker	2	1	2	1	0	1.65
	Wall	474	5,952	24				2.99						2	1	3	1	2	2.25
	Dietz	834	17,516	42	7,467-9,502	0.29	0.65	3.22	5.87					2	2	2	1	2	1.90
	Canyon	159	4,066	8	8,446-9,113	0.24	0.5	3.95	5.817					3	3	2	1	0	2.00
Canyon Creek	Wall	1,884	23,859	94	8,530-9,670	0.33	0.65	2.46	4.629	Steep terrain after riverbed and then it flattens out (max. elevation is 3600 feet)	2	16	Decker	3	2	3	3	3	2.95
	Brewster-Arnold	66	2,067	3	7,979-8,859	0.40		4.82	7.557					3	1	2	3	0	2.10

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
Birney	Brewster-Arnold	181	6,969	9	7,987-9,417	0.42	0.8	5.09	5.153	Mixture of small and large mountains some with very steep hillsides.	5	33	Decker	3	1	2	3	0	2.10
Poker Jim Lookout	Anderson and Dietz	873	19,609	44	7,637-8,374	0.37	0.8	3.01	5.202	Valley surrounded by steep terrain	7	30	Decker	2	1	2	2	2	1.95
Hanging Woman Creek	Anderson	1,583	30,547	79	6,751-9,259	0.33	0.8	2.76	11.057	Flat in the creek bed, then rolling hills	22	22	Decker	2	2	3	1	3	2.50
	Dietz	1,121	43,654	56	7,722-8,707	0.48	1.5	3.49	5.507					2	1	2	1	3	2.05
West Moorhead	Anderson	884	19,660	44	7,950-8,790	0.37	0.8	3.3	5.333	Flat in the creek bed, then rolling hills	35	47	Terminus 2	2	1	2	1	2	1.85
	Dietz	397	20,416	20	7,907-8,080	0.42	1.5	4.3	4.127					1	1	2	1	2	1.60
	Canyon	690	22,547	35	7,419-8,920	0.40	0.8	5.2	5.342					2	1	2	1	2	1.85
Poker Jim Creek-O'Dell Creek	Knobloch - Plate 11A and 11B	938	15,077	47	8,380-9,135	0.25	0.5	3.34	5.104	Previously planned mining area. Max. topographic relief within the mine plan area is ~600 feet in Montco Mine EIS.	2	30	Decker	3	2	2	3	0	2.15
Otter Creek ^j	Tract 1 (Knobloch)	435	5,410	22	8,600	0.27	0.65	3:1	4.71	Planned mining area. Relatively flat.	<1	34	Terminus 2	3	2	2	3	2	2.35
	Tract 2 (Knobloch)	676	7,639	34				3:1											
	Tract 3 (Knobloch)	594	5,170	30				2.9:1											
Ashland ^k	Knobloch	2,696	27,200	135	7,671-9,070	0.15	0.5	2.58	4.829	Relatively flat; located mostly in Custer National Forest. Includes City of Ashland.	2	24	Terminus Points	2	1	3	3	3	2.65
	Sawyer, A and C	357	20,262	18	7,740-7,965	0.49	1.5	6.55	4.906					1	3	1	3	0	1.30

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
Pumpkin Creek	Sawyer	2,427	45,695	121	7,140-7,570	0.52	1.5	3.25	7.864	Flat in the riverbed, then rolling hills and some steep terrain.	2	10	Tongue River Road	0	1	2	3	3	2.00
Foster Creek	Knobloch	708	27,801	35	7,380-7,840	0.77	1.5	4.22	7.89	Relatively flat; small mountains in land max. elevation is 3100 feet	2	19	Tongue River Road	0	1	2	3	2	1.80
	Terret	461	27,462	23		0.22		6.53	5.877					0	3	1	3	2	1.50
	Flowers-Goodale	259	14,444	13		0.51		6.11	7.857					0	1	1	3	0	1.20
Broadus	Broadus	740	18,429	37	7,438	0.27	0.8	3.68	7.17	Relatively flat with rolling hills. Close to city limits of Broadus, MT.	38	68	Terminus 2	0	2	2	1	2	1.65
East Moorhead	T	525	15,559	26		0.57		3.84	6.205	Flat in the creek bed, then rolling hills	34	47	Terminus 2	0	1	2	1	2	1.60
Diamond Butte	Canyon	418	21,363	21	7,138-7,897	0.44	1.5	5.74	4.801	Valley surrounded by steep terrain	18	38	Terminus 2	0	1	2	1	2	1.60
Goodspeed Butte	Cook	629	13,446	31	6,682-6,861	1.64	1.5	4.18	10.656	Valley surrounded by steep terrain	15	43	Terminus 2	0	1	2	1	2	1.60
Fire Gulch	Pawnee and Cook	337	8,486	17	7,650	0.33	0.8	4.39	3.894	Steep terrain outside riverbed.	30	58	Terminus 2	0	2	2	1	0	1.45
Sweeney Creek-Snyder Creek	Terret	326	10,921	16		1.19		2.97	9.248	Relatively flat; small mountains in land max. elevation is 3100 feet	2	23	Tongue River Road	0	1	3	3	0	2.00
Yager Butte	Elk and Dunning	1,176	26,924	59		0.34		3.2	6.716	Valley surrounded by rolling hills and forested areas.	8	40	Terminus 2	0	2	2	2	3	1.95
	Cook	312	14,507	16	5,881-7,703	0.64	1.5	6.5	4.896					0	1	1	3	0	1.20
Threemile Buttes	Canyon and Ferry	225	13,836	11	6,646-7,133	0.94	1.5	5.76	5.587	Valley surrounded by steep terrain	12	46	Terminus 2	0	1	2	1	0	1.40
Sonnette	Pawnee	320	8,224	16	5,556-7,902	0.88	1.5	4.15	9.848	Relatively flat	18	50	Terminus 2	0	1	2	1	0	1.40

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)] ⁱ	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
	Cook	363	10,470	18	6,547-7,186	1.24	1.5	5.06	8.59	with rolling hills.				0	1	2	1	0	1.40
Home Creek Butte	Canyon and Ferry	217	4,851	11				3.12		Valley surrounded by rolling hills and forested areas.	14	38	Terminus 2	0	1	2	1	0	1.40
Little Pumpkin Creek	A, Sawyer, C and D, X, and E	216	8,534	11				5.3		Relatively flat with rolling hills and forested areas.	20	40	Terminus 2	0	1	2	1	0	1.40
Sand Creek	Knobloch	267	5,952	13	7,220-7,460	0.30	0.8	2.22	6.675	Relatively flat; small mountains in land max. elevation is 3100 feet	2	19	Tongue River Road	0	2	3	3	0	2.05
Beaver Creek- Liscom Creek	Flowers- Goodale, Terret, and Knobloch	627	25,926	31	7,362-8,417	0.53	1.5	4.97	7.668	Relatively flat along Tongue River; becomes mountainous when you head inland in all directions.	1	23	Tongue River Road	0	1	2	3	2	1.80
Greenleaf Creek- Miller Creek	Rosebud, Knobloch, and Sawyer	454	14,918	23		0.72		3.97	7.584	Steep terrain outside of the Greenleaf creek area, relatively flat terrain north of Greenleaf Creek along Rosebud Creek	1	10	Colstrip	0	1	2	3	2	1.80
Pine Hills	Dominy	194	6,022	10	7,220-7,420	0.54	1.5	3.69	7.23	Located in Pine Hill Reservoir. Relatively flat valley surrounded by steep terrain.	10	20	Tongue River Road	0	1	2	1	0	1.40
Knowlton	Dominy (M & L)	748	19,613	37	6,297-6,850	0.42	1.5	3.61	10.531	Mixed terrain of flat ranch lands, rolling hills, and steep mountains.	32	28	Tongue River Road	0	1	2	1	2	1.60
	Dominy (U)	120	4,448	6	6,297-6,850	0.77	1.5	2.15	5.655					0	1	3	1	0	1.80

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
Colstrip (Rosebud Mine & Colstrip PP)	Rosebud	1,439	33,379	72	7,810-9,090	1.27	1.5	2.83	9.195		4	<2	Colstrip	2	1	3	3	3	2.65
Decker (W. Decker & Spring Ck mines)	Anderson and Dietz 1&2	2,240	25,523	112	6,019-9,850	0.32	0.8	2.52	6.944		4	<1	Decker	0	2	3	3	3	2.20
Deer Creek (E. Decker Mine)	Anderson and Dietz 1&2	496	14,214	25	6,594-9,247	0.58	1.5	8.78	8.16	Near WY border, relatively flat, also near Decker	4	<1	Decker	0	1	1	3	2	1.15
Total PRB Coal (million tons):	31,654																		
Total excluded based on production rate of <20 million tons/yr:	532																		
Total excluded based on heat content of <8,000 Btu/lb:	12,069																		
Total excluded because existing or proposed mine:	4,175																		

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	
Total excluded because >15 miles from nearest rail alternative	6,359																		
Total excluded because of location in Custer NF or City of Ashland	3,926																		
Total Montana PRB Coal After Above Exclusions:	4,593						Theoretical annual total (million tons per year) with a 20- year life:	230											

Coal Deposit ^{a, b}	Coal bed	Reserves (million tons)	Acreage	Annual Coal Production Rate ^c	Heat Content (Btu/lb) ^d	Sulfur Content (%) ^e	Sulfur Categories [lbs SO ₂ per MMBtu (0.5, 0.65, 0.8, 1.5)]	Overburden Ratio	Ash Content (%) ^f	Topography	Estimated Distance from Proposed Railroad (miles) ^{g, h}	Distance from Existing Rail Lines (miles) ⁱ	Closest Alternative	Scores					Score with Weighting Factors Applied
														Btu	Sulfur	OB Ratio	Distance	Annual Coal Production	

a. Northern Cheyenne or Crow Tribe reservations were not included in field studies

b. Avg. length of a coal conveyor belt is between 5-15 miles (http://www.che.utexas.edu/course/che359&384/lecture_notes/topic_3/Chapter4.pdf).

c. Some coal deposits are already being mined (such as Colstrip and Decker)

d. According to Chris Yde at MDEQ, the state determines the next available coal tracts for lease based upon the overall heat content. MDEQ looks for a Btu content between 8,500-8,800 Btu/lb before leasing a tract. (Phone communication: 02/20/2013).

e. Average of as received sulfur content across all bore hole measurements provided in Matson and Blumer 1973.

f. Otter Creek mine is already in the permit/EIS process to be mined in the near future. The leased coal tracts do not cover the entire Otter Creek Coal Deposit. This data represents the leased Otter Creek mine area from the Arch Coal permit application (Arch Coal. 2012. Arch Coal Otter Creek Mine Permit Application. Available: http://deq.mt.gov/pubcom.mcp#Otter_Creek. Accessed: March 18, 2013.)

g. Average round-trip haul distance for a truck at the Decker mines is 4 miles.

h. Assuming a 20-year life mine.

i. Average of as received ash content across all bore hole measurements provided in Matson and Blumer 1973.

j. Existing rail lines include the Decker Spur to the South, mainly for the new Southern Alternative and the BNSF mainline near Miles City/Forsyth and Colstrip spur.

k. Location within Custer National Forest also was found to be an exclusionary factor. This applies only to the Ashland deposit.

Source: Matson and Blumer. 1973. Quality and Reserves of Strippable Coal, Selected Deposits, Southeastern Montana. Montana Bureau of Mines and Geology.

The specific factors included in the evaluation, and the relative importance of each factor, were determined based on industry knowledge and available geological survey data, as well as the inputs needed for the modeling. OEA used the model to determine the domestic and international market for the coal deposits in the project area (Chapter 5, *Model Framework, Methods, and Key Assumptions*). Table 3-3 summarizes the weighted determination factors, which are also discussed in the following subsections.

Of the weighting factors in Table 3-3, the overburden ratio is the most important factor affecting the potential for induced mining. Heat content of the coal ranks second, followed closely by annual coal production. The distance to the proposed rail line and sulfur content were considered not as important as the other factors, except that a distance of greater than 15 miles was considering an exclusionary criterion. If the reserves are large enough, either a system of trucking and conveyor belts could be used to transport the coal to a rail line or an additional rail spur could be constructed. However, for the purposes of this analysis, OEA assumed that building an additional rail spur would be too costly. As a result, OEA eliminated from further study any mines located more than 15 miles from the proposed rail line.

Table 3-3. Key Factors Affecting Potentially Induced Coal Mining

Factor	Metrics	Scoring	Weight Factor (%)
Overburden ratio	1–3; >3–6; >6	3, 2, 1	40
Heat content (Btu/lb)	≥8,500; 8,499–8,001; ≤8,000	3, 2, 0 (exclude)	25
Coal production (million tons/year)	>50; 20–50; <20	3, 2, 1	20
Distance to proposed rail line (miles)	0–5; >5–10; >10–15; >15	3, 2, 1, 0 (exclude)	10
Sulfur content (%)	<0.25; 0.25–0.35; >0.35	3, 2, 1	5
Total			100
Notes:			
Btu/lb = British thermal unit per pound			

OEA used a range of metrics for each factor to determine the overall feasibility of the particular coal deposit. A higher score indicates that the coal deposit has a higher feasibility for extraction. OEA evaluated the coal deposits with the highest scores to identify any leasing restrictions and determine overall coal marketability. Coal deposits receiving a score of zero in any category did not meet the criteria of mining feasibility, and OEA excluded them from further study.

3.2.2.1 Overburden Ratio

Coal seams are covered by a layer of overburden (dirt and other earth materials) that is not coal bearing. The thickness of the overburden can vary throughout a coal deposit because of changes in geologic and topographic conditions. Overburden ratio refers to the ratio of overburden that must be excavated to the amount of coal that may be removed. OEA used the average overburden ratio over the expected life of the mine (20 years) to assess the

economic viability of coal deposits. For example, for the Otter Creek Coal Deposit Tract 2 (Line 10 of Table 3-2), an average of 3 tons of overburden must be removed for every 1 ton of coal (3:1). The overburden ratio can change over the lifetime of a mine. Overburden can be removed using draglines and truck-shovel fleets.

The metrics used for determining the overburden ratio for each coal deposit were as follows.

- A ratio of 1:1 to 3:1 was given the highest score (3).
- A ratio of 3.1:1 to 6:1 was given the middle score (2).
- A ratio of 6.1:1 or more was given the lowest score (1).

Coal reserves with an overburden ratio greater than 6:1 were given the lowest score because the economic viability of the mine decreases as the overburden ratio increases. Coal deposits were not excluded, or given a score of zero, in the category of overburden ratio because a mine could still operate and be permitted with a ratio greater than 6:1.

3.2.2.2 Heat Content

Heat content is measured in Btu/lb. The heat content relates to the coal's ability to generate heat when burned at a power plant. The higher the heat content the less coal is needed to produce the same amount of energy. Coals with more than 8,500 Btu/lb are among the most competitive in the U.S. and international coal markets. OEA used the range of heat values to rank a coal deposit (Matson and Blumer 1973).

The metrics used for determining the heat value of each coal deposit were as follows.

- Heat content of more than 8,500 Btu/lb was given the highest score (3).
- Heat content between 8,499 Btu/lb and 8,001 Btu/lb was given a lower score (2).

The State of Montana does not consider coal deposits with heat content less than 8,000 Btu/lb for competitive leases (Yde pers. comm.). It would not be efficient to burn coal with such a low heat content and high moisture content, and it would not be economically viable to develop or market such coals. Those deposits were given a score of zero and were excluded from further analysis. OEA included smaller coalbeds with low heat values located in a larger deposit with a higher heat content if it appeared that the coal could be blended and still provide an average heat content of more than 8,000 Btu/lb for the deposit overall.

3.2.2.3 Amount of Mineable Coal Reserves

The amount of mineable coal reserves contributes to the production rate, which is calculated over the life of the mine. OEA calculated the production rate by dividing the total recoverable coal reserves by an average mine life of 20 years. On average, a Powder River Basin mine operates between 10 and 20 years (John T. Boyd Company 2013). Although a mine may be capable of producing over 20 million tons per year, the actual permitted production rate may be far less. For example, the Otter Creek Mine permit application

anticipates mining of 20 million tons per year for 20 years although the coal deposit may be capable of producing between 30 and 35 million tons per year for more than 20 years. The coal production scenarios show both the anticipated permitted capacity of a mine based on previous and current mine permit applications submitted to Montana DEQ and the potential coal production from the entire coal deposit. For example, the Poker Jim Lookout coal deposit has 873 million tons of total coal reserves. Over a 20-year mine life, the annual production potential is equal to 43.65 million tons.

The metrics used for determining the production rate of each coal deposit were as follows.

- Production rate greater than 50 million tons per year was given the highest score.
- Production rate between 20 and 50 million tons per year was given a lower score.

OEA excluded coal deposits that would be mined at a production rate of less than 20 million tons per year based on an average 20-year mine life based on total reserves. However, OEA retained small coalbeds that are part of a larger coal deposit if the larger deposit would be mined at a production rate of more than 20 million tons per year. These embedded deposits are more likely to be mined than small beds in a separate area because they could be mined at a comparatively lower incremental cost.

3.2.2.4 Distance to the Proposed Rail Line

The distance of a coal deposit to the proposed rail line would have a direct effect on the cost of production. Coal deposits distant from the rail line would require additional capital investment for rail spurs and might not be readily accessed using a system of conveyor belts and trucks to move coal to the loading facility. OEA assumed that the length of a coal conveyor belt is between 5 and 15 miles, and that the average round-trip haul distance for a truck would be 4 miles.²

The metrics used for determining the distance to the proposed rail line were as follows.

- Deposits within 5 miles of the proposed rail line were given the highest score (3).
- Deposits within 5 to 10 miles of the proposed rail line were given the middle score (2).
- Deposits within 10 to 15 miles of the proposed rail line were given the lowest score (1).

OEA concluded that coal deposits located farther than 15 miles from the proposed rail line would not likely be mined in the foreseeable future; therefore, these deposits were given a score of zero and eliminated from further study.

3.2.2.5 Sulfur Content

Low-sulfur coal is more desirable in today's coal market because it reduces the amount of sulfur dioxide (SO₂) emissions, which enables domestic power plants to meet Clean Air Act

² These assumptions are based on the operations of the existing Decker mine located south of the project area. Average round-trip haul distance for a truck at the Decker mines is 4 miles.

emission requirements with less costly emission controls. High-sulfur coal requires additional emissions control equipment, such as scrubbers, which increases operating costs. Although the sulfur content of the coal reserves is relevant to its marketability, this factor has the lowest weight because most power plants can accommodate both high- and low-sulfur coals.

The metrics used for determining the sulfur content were as follows.

- Coal with sulfur content below 0.25% was given the highest score (3)
- Coal with sulfur content between 0.25 and 0.35% was given the middle score (2)
- Coal with sulfur content above 0.35% was given the lowest score (1)

3.2.2.6 Sodium Content

The coal located in the Powder River Basin has a relatively high sodium content. High-sodium coal can be problematic for some power plants because it causes ash to accumulate in the boilers, creating conditions known as slagging and fouling. However, despite the potential for slagging and fouling, several domestic power plants use high-sodium coal for combustion. OEA concludes that sodium content is not a factor that would prevent the coal from being sold. For a more detailed discussion of sodium content, please see Attachment A, *Sodium Analysis of Tongue River Coal Deposits*.

After all of the weighting factors (overburden ratio, heat content, amount of reserves, distance, sulfur, and sodium content) were applied, 8 of the 32 initially identified coal deposits remained viable for further analysis (Table 3-4).

Table 3-4. Coal Deposits Identified for Further Study Based on Weighting Factors

Coal Deposit ^a	Coalbed	Annual Coal Production Rate ^b	Heat Content (Btu/lb)	Sulfur Content (%)	Overburden Ratio	Distance from Proposed Railroad (miles)	Score with Weighting Factors Applied					
							Btu/lb	Sulfur	Overburden Ratio	Distance	Annual Coal Prod.	Score
Canyon Creek	Wall ^c	94	8,530–9,670	0.33	2.46	2	3	2	3	3	3	2.95
Poker Jim Lookout	Anderson and Dietz	44	7,637–8,374	0.37	3.01	7	2	1	2	2	2	1.95
Poker Jim Creek–O'Dell Creek	Knobloch - Plate 11A and 11B	47	8,380–9,135	0.25	3.34	2	3	2	2	3	1	2.15
Otter Creek ^d	Tract 1 (Knobloch)	22	8,600	0.27	3:1	<1	3	2	2	3	2	2.35
	Tract 2 (Knobloch)	34			3:1							
	Tract 3 (Knobloch)	30			2.9:1							
Ashland ^e	Knobloch	135	7,671–9,070	0.15	2.58	2	2	1	3	3	3	2.65
Colstrip (Rosebud Mine & Colstrip PP)	Rosebud	72	7,810–9,090	1.27	2.83	4	2	1	3	3	3	2.65
Decker (West Decker & Spring Creek Mines)	Anderson and Dietz 1&2	112	6,019–9,850	0.32	2.52	4	1	2	3	3	3	2.45
Deer Creek (E. Decker Mine)	Anderson and Dietz 1&2	25	6,594–9,247	0.58	8.78	4	1	1	1	3	2	1.40

Notes:

^a Northern Cheyenne or Crow Tribe reservations were not included in field studies

^b Assuming a 20-year mine life

^c The Canyon Creek deposit is composed of two coalbeds, the Wall and the Brewster Arnold. The Brewster Arnold coalbed was eliminated from further study because it has a small amount of available reserves. It is assumed that this coalbed would not be mined.

^d The tracts represent the identified mine tracts form the Arch Coal permit application. All three of these tracts are within the Otter Creek coal deposit.

^e The Ashland deposit is composed of two coalbeds, Knobloch and Sawyer. The Sawyer coalbed was eliminated from further study because the coal has a low heat content and high overburden ratio. It is assumed that this coalbed would not be mined.

Source: Matson and Blumer 1973, Norwest 2006

3.2.2.7 Land Use Restrictions and Concerns

OEA considered potential land use restrictions on coal mine development in the project area. These restrictions were applied to the 32 identified coal deposits as exclusionary criteria. These exclusionary factors are described below.

Custer National Forest

Coal deposits in the Custer National Forest were excluded from further analysis because the Surface Mining Control and Reclamation Act (SMCRA) of 1977 specifically excludes the Ashland District of the Custer National Forest from “strip/open pit coal mining” (Office of Surface Mining Reclamation and Enforcement 1977).

Secretary finds that there are no significant recreational, timber, economic, or other values which may be incompatible with such surface mining operations and --

(A) surface operations and impacts are incident to an underground coal mine; or

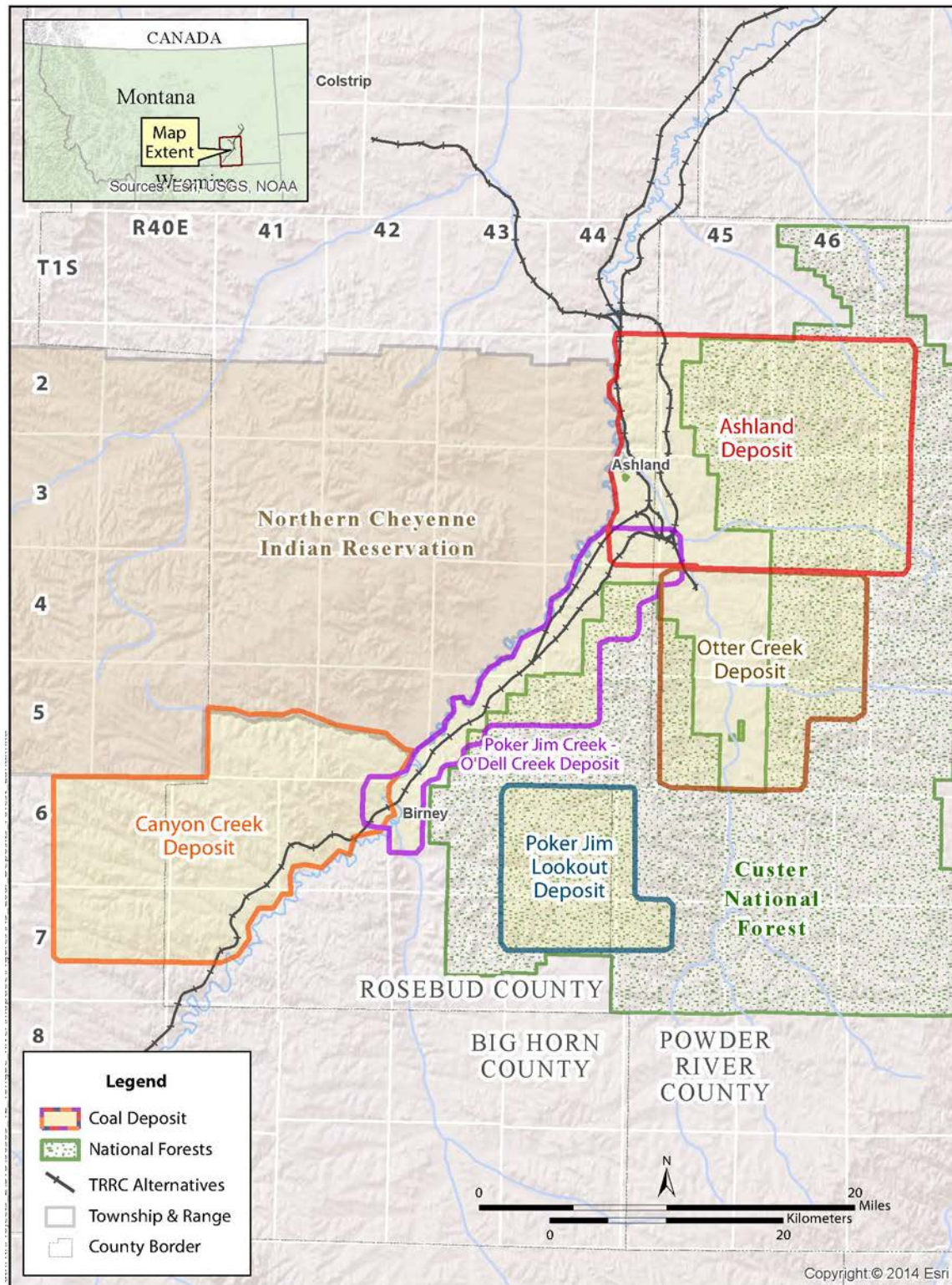
(B) where the Secretary of Agriculture determines, with respect to lands which do not have significant forest cover within those national forests west of the 100th meridian, that surface mining is in compliance with the Multiple-Use Sustained-Yield Act of 1960 [16 USC §§ 528 *et seq.*], the Federal Coal Leasing Amendments Act of 1975, the National Forest Management Act of 1976, and the provisions of this Act: and provided further, that no surface coal mining operations may be permitted within the boundaries of the Custer National Forest.

OEA assumes that, unless SMCRA is repealed or amended, the U.S. Forest Service would not allow surface mining coal leases on Custer National Forest land. This exclusionary criterion eliminated the entire Poker Jim Lookout coal deposit and a large portion of the Ashland deposit (Table 3-4). Figure 3-2 shows the location of the Poker Jim Lookout coal deposit and other area deposits that were identified for further study.

Although the Ashland coal deposit received a high rating for feasibility, it was excluded from further consideration because a large amount of the deposit is located in Custer National Forest, a portion of the deposit is located under a small town, and the remaining reserves are of a poor quality and located under land whose surface rights are owned by large ranches.³ The remaining Ashland reserves have thinner coal seams with the same average overburden ratio of 3:1, or are located under privately owned land that would require surface owner consent.

³ U.S. law distinguishes *surface rights*—the right to use land for agriculture or housing—from *mineral rights* (or *subsurface rights*) that confer the right to extract minerals from below the surface of the land. Thus, a ranch owner may own the surface rights, but not own the mineral (or subsurface) rights.

Figure 3-2. Coal Deposits on Custer National Forest



Northern Cheyenne Reservation

Coal deposits in the Northern Cheyenne Reservation were excluded from further analysis because they have not been adequately included or characterized in reports on regional deposits.⁴ Coal mining on the Northern Cheyenne Reservation would require approval from the Northern Cheyenne Tribe. Currently, coal mining operations are not approved on the Northern Cheyenne Reservation. For this reason, OEA did not evaluate any potential mines located on the Northern Cheyenne Reservation.

Existing Area Mines

Existing strip mines in the project area include the Spring Creek, Decker, and Rosebud Mines that already are producing coal from the Colstrip, Decker, and Deer Creek coal deposits (Table 3-2). These mines are listed in Table 3-4 as coal deposits identified for further study because the coal quality of the coal deposits mined at these existing facilities is of a high quality that it received high scores based on the weighting factor analysis. However, OEA subsequently excluded these coal deposits from further study because these mines have already been permitted and have established contracts with U.S. power plants. The Tongue River Railroad would not be used to transport coal from these mines because each mine has access to an existing rail spur (the BNSF Spring Creek Rail Spur), which connects to the BNSF mainline and on to the power plants. There would be no transportation advantage or savings for these mines to use Tongue River Railroad because they have established routes to bring their coal to the contracted power plants via the rail spur and mainline.

Zook Creek Wilderness Study Area

A total of 2,768 acres of the Canyon Creek coal deposit are part of the Zook Creek WSA. As part of BLM's coal leasing program there are 20 criteria used to evaluate the suitability of a potential coal deposit; criterion number 4 establishes that federal lands designated as WSAs shall be considered unsuitable while under review by the Administration and the Congress for possible wilderness designation. The Zook Creek WSA was proposed to Congress for designation in 1993. It is currently being managed by BLM and awaiting a decision on formal designation. Prior to a formal designation, the WSA would undergo a mineral survey by the U.S. Geological Survey and U.S. Bureau of Mines (Bureau of Land Management 2001) (43 C.F.R. Part 3461). According to the *Draft BLM Miles City Resource Management Plan* (Bureau of Land Management 2013), if the WSA was dropped from wilderness consideration, it could be screened further for leasing consideration. The unsuitability screening process is noted as preliminary and will be reviewed and completed when a specific coal tract proposal is made (Bureau of Land Management 2013).

⁴ For example, Matson and Blumer 1973, U.S. Geological Survey 2013.

3.2.3 Proposed and Potentially Induced Mines

OEA applied the exclusionary criteria and weighting factors discussed above to the available coal deposits in the project area. This yielded three coal deposits for further analysis: the proposed Otter Creek Mine, and the potentially induced coal deposits at Poker Jim Creek–O’Dell Creek, and Canyon Creek (Figure 3-3). Figure 3-3, *Proposed or Potentially Induced Mines*, represents the mine footprint as identified by Arch Coal for the proposed Otter Creek Mine and the entire coal deposit for the potentially induced mines. Figure 3-3 is not representative of what a potential mine plan might be; mining would not take place within the right-of-way even though Figure 3-3 shows coal being located within this area.

Approximately 230 million tons of coal per year could be produced over a 20-year period from all three of the proposed Otter Creek Mine coal tracts, Poker Jim Creek–O’Dell Creek deposit(s), and Canyon Creek deposit (Table 3-5) based on all available reserves in these coal deposits. This level of production is equivalent to almost half of the current production in the Wyoming portion of the Powder River Basin, which, according to the BLM, is currently producing around 425 million tons per year (Bureau of Land Management 2012). However, OEA does not anticipate this level of production from these proposed or potentially induced mines. Several assumptions about production levels, startup times, and available reserves were used in the analysis, which reduced the potential production levels to between 20 million tons per year and 72 million tons per year, depending on the alternative and scenario as explained for each proposed or potentially induced mine in the subsections that follow, see Sections 3.2.3.1, *Otter Creek Mine*, 3.2.3.2, *Poker Jim Creek–O’Dell Creek Deposit*, and 3.2.3.3, *Canyon Creek Deposit*.

Table 3-5. Proposed or Potentially Induced Coal Mines

Coal Deposit ^a	Coalbed	Annual Coal Production (million tons /year) ^b	Heat Content (Btu/lb)	Overburden Ratio	Sulfur Content (%)	Distance from Proposed Rail Line (miles)
Canyon Creek ^c	Wall	94	8,530–9,670	2.46	0.33	2
Poker Jim Creek–O’Dell Creek	Knobloch - Plate 11A and 11B	47	8,380–9,135	3.34	0.25	2
Otter Creek	Tract 1 (Knobloch)	22	8,600	3:1	0.27	<1
	Tract 2 (Knobloch)	34		3:1		
	Tract 3 (Knobloch)	30		2.9:1		
Total		230				

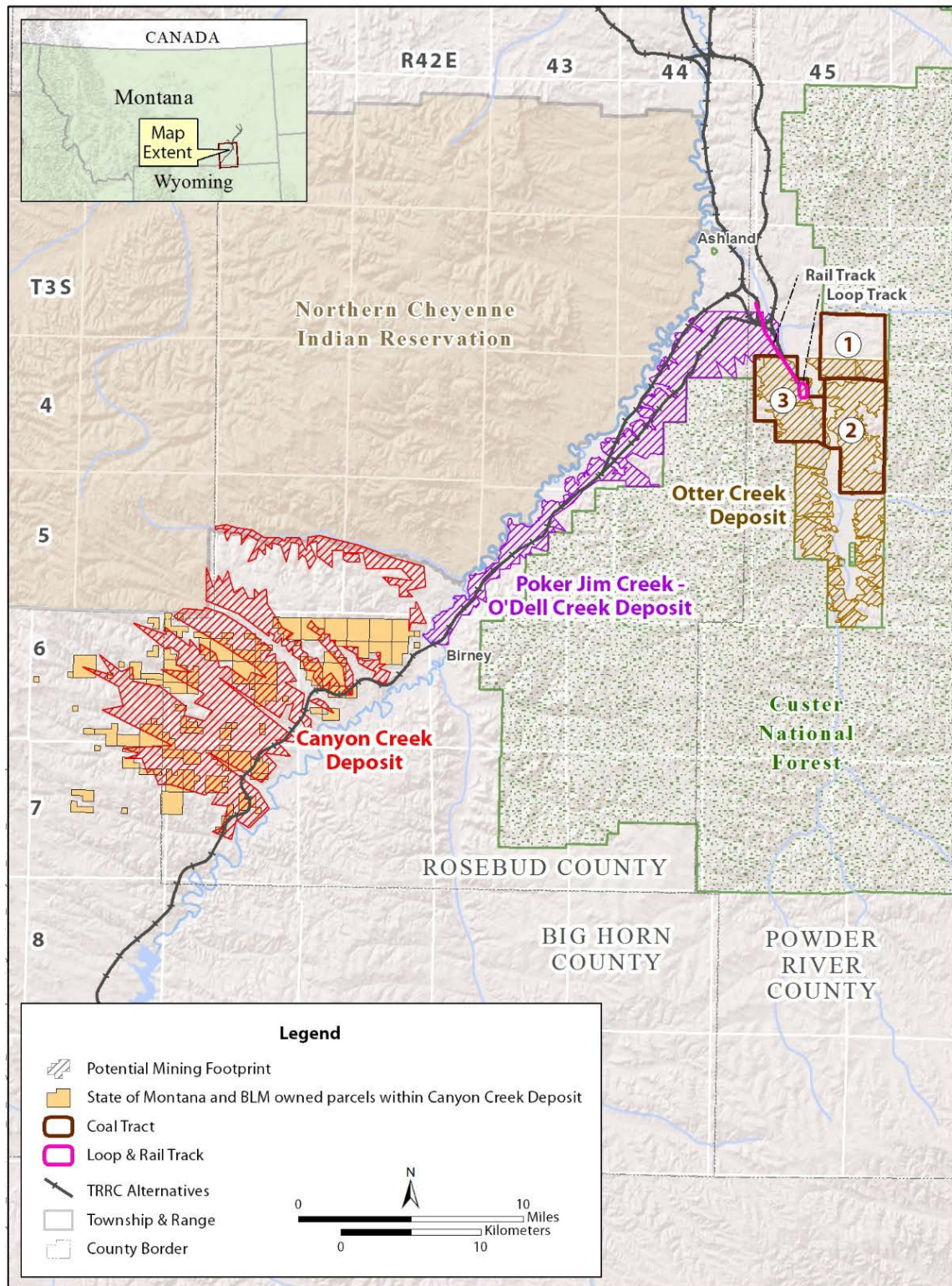
^a Northern Cheyenne or Crow Tribe reservations were not included in field studies

^b Assuming a 20-year life mine

^c The Canyon Creek deposit is composed of two coalbeds, the Wall and the Brewster Arnold. The Brewster Arnold coalbed has been eliminated from further study because of the small amount of available reserves. It is assumed that this coalbed would not be mined.

Sources: Matson and Blumer 1973, Norwest 2006N/A = not available; Btu/lb = British thermal units per pound

Figure 3-3. Proposed or Potentially Induced Coal Mines



3.2.3.1 Otter Creek Mine

The mine plan submitted with the Otter Creek Mine permit application and mine plan identifies three potential coal lease tracts (Montana Department of Environmental Quality 2012). Although the Otter Creek coal deposit is larger than the three coal tracts, these three coal tracts were established based on coal quality and through land lease agreements between Great Northern Properties, Arch Coal, the State of Montana, and BLM. The first is Tract 2 for 18 years, followed by Tract 3 (years 18 to 41), and then Tract 1 (years 40 to 55). OEA's analysis period is 20 years once the mine is in operation beginning in year 2018 and ending in year 2037. Even though the submitted mine plan outlines Tract 2 as being operational for 18 years, the permit application goes on to clarify that, "The mine plan is designed to produce approximately 20 million tons of coal annually for 17–20 years." (Otter Creek Permit Application, 17.24.308: Operations Plan, Exhibit 308A. March 6, 2013.) Therefore, the OEA analysis only evaluates Tract 2 for the period of 20 years. Tracts 1 and 3 are not reasonably foreseeable mining operations because operations beyond the 20-year analysis period are speculative, as additional permits from Montana DEQ would be required.

The coal in all tracts of the Otter Creek deposit is of a relatively high quality with an average heat content of 8,600 Btu/lb, sulfur content of 0.27%, and an overburden ratio of 3:1. Total reserves are 676 million tons in Tract 2, which covers 6,699 acres.

3.2.3.2 Poker Jim Creek–O'Dell Creek Deposit

The coal in the Poker Jim Creek–O'Dell Creek deposit is composed of two coalbeds, Knobloch Plate 11A and Knobloch Plate 11B. Both areas contain a relatively high-quality coal with an average heat content of 8,758 Btu/lb, sulfur content of 0.25%, and an overburden ratio of 3.2:1. Total reserves are 938 million tons. The coal deposit covers an area of approximately 15,077 acres (Matson and Blumer 1973). The previously planned Montco Mine was in the Poker Jim Creek–O'Dell Creek deposit. Montco Mine was approved by the Montana Department of State Lands in 1984 and had its permit revoked in 1997 by Montana Department of Environmental Quality and the Montana Department of State Lands because operations had not commenced (*Montco v. Simonich* 947 P.2d 1047, No. 96-656, Oct. 31, 1997). The previously planned Montco Mine was 10,171 acres (U.S. Department of the Interior 1984).

3.2.3.3 Canyon Creek Deposit

The Canyon Creek deposit is composed of two coalbeds, the Brewster-Arnold and the Wall. The Brewster-Arnold coalbed has relatively low-quality coal and a minimal amount of reserves. The Wall coalbed contains relatively high-quality coal with a heat content range of 8,530 to 9,670 Btu/lb, sulfur content of 0.33%, and an overburden ratio of 2.46:1. Total reserves are 1,884 million tons. The coal deposit covers an area of approximately 108,000 acres based on GIS mapping. BLM has identified portions of the Canyon Creek deposit as

potentially acceptable for further study pending a formal lease application (Bureau of Land Management 2013).

BLM and the State of Montana own approximately 23% of the coal deposit's surface rights and approximately 90% of the mineral rights, and both agencies have active coal leasing programs.⁵ The remaining surface rights belong to the Diamond Cross Ranch, the Brown Cattle Company, Montaylor Corporation, Big Bend Ranch, Quarter Circle U Ranch, the Northern Cheyenne, and the Jordan Ranches LTD Partnership. OEA has focused primarily on the land that could be leased from the state or BLM, (i.e., both mineral and surface rights belong to them). However, because of purchase or leasing agreements with private landowners for surface rights and approval from the BLM or State of Montana for release of the mineral rights, additional land could become available for mining through future leasing programs.

3.3 Marketable Coal Production Scenarios

For purposes of this analysis, OEA developed coal production scenarios⁶ based on the geographic locations of the alternatives for the proposed rail line. As defined in Chapter 2, *Proposed Action and Alternatives*, of the Draft EIS, the northern alternatives include the Tongue River Alternatives,⁷ Colstrip Alternatives, Tongue River Road Alternatives, and Moon Creek Alternatives. The southern alternatives include the Decker Alternatives. OEA chose to use the lowest estimated northern and southern alternative Tongue River Railroad capital cost as representative of the northern and southern alternatives for this analysis. This allows for the generation of a more conservative maximum amount of Tongue River coal that could be induced (i.e., tending to overstate the production of Tongue River coal). These two representative northern and southern alternatives were combined with low, medium, and high production rates. OEA used the resulting six scenarios (three northern alternative and three southern alternative scenarios) as modeling inputs along with factors such as transportation distance, rail costs, and coal export terminal capacity, as described in Chapter 5, *Model Framework, Methods, and Key Assumptions*, and Chapter 7, *Scenarios*.

⁵ Calculated from the total coal deposit acreage of 108,000 acres divided by the total BLM and State of Montana surface right acreage to equal 23% of the total acreage.

⁶ The term *scenario* refers to a combination of variables that represents a route alternative, a level of production, and a level of terminal capacity growth. These scenarios are detailed completely in Chapter 7, *Scenarios*. This chapter addresses the assumptions underlying coal production for these scenarios.

⁷ Each pair of alternatives consists of the primary route and the primary route with the Eastern Variation. For example, the Tongue River Alternatives include both the Tongue River Alternative and the Tongue River East Alternative. The Eastern Variation includes both the Ashland East Variation segment and the Terminus 1 Variation segment. Because the Decker Alternatives would travel south toward Decker, Montana, only the Terminus 1 Variation segment can be applied, not the entire Eastern Variation. See Chapter 2, *Proposed Action and Alternatives*, of the EIS for further details.

3.3.1 Assumptions

The assumptions supporting the coal production rates and trains per day rates as well as the expected output capacity of each mine are described below.

3.3.1.1 Analysis Period

The development schedule for the potential mines was based on the proposed Otter Creek Mine schedule. Under that schedule, the estimated period for bringing a new mine into operation is 5 years. TRRC submitted the permit application for the Otter Creek Mine on July 26, 2012, and based on the schedule, it expects to begin mining in January 2017 (Surface Transportation Board 2012). OEA's analysis period is 20 years, 2018 to 2037, and is based on Otter Creek Mine Company's mine plan submitted for its mining permit application. The application assumes that Otter Creek Mine is permitted and becomes operational in 2018, although 2017 was identified previously as the first year of operation in TRRC's filing. Due to delays in the mine permit application review and noted deficiencies, it is more likely to assume that the Otter Creek Mine will be permitted and operational by 2018. The mine plan submitted for the permit application forecasts mining for a 55-year period with Tract 2 under production within the first 20 years. Otter Creek would decide whether to mine beyond 20 years based on market conditions at that time. The Otter Creek Mine plan does show continued mining in Tract 3 and Tract 1 beyond 20 years; however, this would require additional permitting (Montana Department of Environmental Quality 2012).

3.3.1.2 Production Rates

TRRC expects that mining operations will begin gradually at the Otter Creek Mine (Tongue River Railroad Company 2013c). The first year of operation is expected to produce 12 million tons of coal, or about 60% of the anticipated permitted production of 20 million tons per year. The second year of operation is expected to produce 16 million tons, or about 80% of the anticipated permitted production. OEA applied this gradual startup to both the Poker Jim Creek–O'Dell Creek deposit and Canyon Creek deposit production rates for years 1 and 2 of mining operations. OEA assumed all three mines to have a 20-year mine life, as is typical of mines in the Powder River Basin, and as stated in the permit application for the Otter Creek Mine.

The Otter Creek Mine served as a template for potential future coal leases. The size of the Poker Jim Creek–O'Dell Creek deposit was adjusted based on the Otter Creek Mine lease size and lease limitations. OEA assumed the Poker Jim Creek–O'Dell Creek deposit excluded any Custer National Forest land and excluded coal reserves in and around the town of Birney, Montana (approximately 1,300 acres). OEA also assumed the same ratio of mined land to leased land as the entire Otter Creek deposit, excluding Custer National Forest (34%). As noted in Section 3.2.2.7, *Land Use Restrictions and Concerns*, surface mining is not allowed within the boundaries of Custer National Forest.

The size of the Canyon Creek deposit was adjusted based on the amount of land (surface rights and mineral rights) owned by BLM, the State of Montana and also included some private land. OEA focused this assessment to include mostly BLM or State of Montana lands (surface and mineral rights), which account for 23% of the entire coal deposit.

Since there are no current mine applications for the Poker Jim Creek–O’Dell Creek and Canyon Creek deposits, OEA has assumed that the mine permit approval and construction processes for these deposits will take 5 years based on the development schedule of the Otter Creek Mine (Section 3.3.1.1, *Analysis Period*). For analysis purposes, OEA assumed that it would take 2 years after construction for the mines to become fully operational (Tables 3-6 and 3-7), and assumed Otter Creek would be fully operational by 2020, Poker Jim–O’Dell Creek in 2025, and Canyon Creek in 2030.

3.3.1.3 Trains per Day

The coal produced at each coal deposit would be transported on the Tongue River Railroad. The number of trains per day was calculated as follows.

- Divide the annual amount of coal production by the number of days the mine would be in operation in a year (assuming 365).
- Divide that value by the tonnage one coal train car can hold (118 tons based on current BNSF operations).
- Divide that value by the maximum number of train cars per coal train (125 as identified in the TRRC application).⁸
- Multiply that value by 2 to represent train trips in and out of the mine.

Example: Otter Creek Mine based on the TRRC application

- 20 million tons of coal produced annually /365 days of mining = 54,794.52 tons per day
- 54,794.52 tons per day/118 tons per coal train car = 464.36 tons per train
- 464.36 tons per train /125 cars per train = 3.71 train trips (one way)
- 3.71 trains (one way) × 2 for inbound and outbound train trips = 7.43 train trips per day

3.3.1.4 Northern Alternatives

The scenarios for the northern alternatives range from a low production of 20 million tons of coal per year corresponding to an average of 7.4 trains per day to a high production of 50 million tons of coal per year corresponding to an average of 18.6 trains per day. These scenarios cover the Otter Creek Mine and the Poker Jim Creek–O’Dell Creek deposit, which

⁸ OEA estimated up to four locomotives and 125 cars on average based on the TRRC’s response to the first information request (February 6, 2013). This is also consistent with current BNSF westbound coal unit train operations and provides an upper bound because eastbound trains have three locomotives and 118 cars on average.

are of a relatively high quality based on the weighting factor scores for heat content, available coal reserves, overburden ratio, sulfur content, and distance.

3.3.1.5 Low Production

The low production scenarios for the northern alternatives (scenarios 3, 4, and 5) are based on the production rate of 20 million tons per year identified in the mine permit application for the Otter Creek Mine, Tract 2 (Montana Department of Environmental Quality 2012).

Table 3-6 shows the coal production, by year, and the associated number of trains per day for the low production scenarios.

Table 3-6. Northern Alternatives Low Production Scenarios

Year	Otter Creek Production (Tract 2) (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per Day
2018	12	12	4.5
2019	16	16	5.9
2020	20	20	7.4
2021	20	20	7.4
2022	20	20	7.4
2023	20	20	7.4
2024	20	20	7.4
2025	20	20	7.4
2026	20	20	7.4
2027	20	20	7.4
2028	20	20	7.4
2029	20	20	7.4
2030	20	20	7.4
2031	20	20	7.4
2032	20	20	7.4
2033	20	20	7.4
2034	20	20	7.4
2035	20	20	7.4
2036	20	20	7.4
2037	20	20	7.4

3.3.1.6 Medium Production

The medium production scenarios for the northern alternatives (scenarios 6, 7, and 8) are based on the annual production rate of 20 million tons per year identified in the mine permit application for the Otter Creek Mine, Tract 2 (Montana Department of Environmental Quality 2012). This scenario also includes the Poker Jim Creek–O’Dell Creek deposit at the previously permitted 12 million tons per year mining capacity, which is the maximum

permitted production capacity (U.S. Department of the Interior 1984). Table 3-7 shows the coal production, by year, and the associated number of trains per day under the medium production scenarios.

Table 3-7. Northern Alternatives Medium Production Scenarios

Year	Otter Creek (Tract 2) (million tons per year)	Poker Jim Creek– O’Dell Creek (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per day
2018	12	–	12.0	4.5
2019	16	–	16.0	5.9
2020	20	–	20.0	7.4
2021	20	–	20.0	7.4
2022	20	–	20.0	7.4
2023	20	7.2	27.2	10.1
2024	20	9.6	29.6	11.0
2025	20	12.0	32.0	11.9
2026	20	12.0	32.0	11.9
2027	20	12.0	32.0	11.9
2028	20	12.0	32.0	11.9
2029	20	12.0	32.0	11.9
2030	20	12.0	32.0	11.9
2031	20	12.0	32.0	11.9
2032	20	12.0	32.0	11.9
2033	20	12.0	32.0	11.9
2034	20	12.0	32.0	11.9
2035	20	12.0	32.0	11.9
2036	20	12.0	32.0	11.9
2037	20	12.0	32.0	11.9

3.3.1.7 High Production

The high production scenarios for the northern alternatives (scenarios 9, 10, and 11) expand to include other areas of potentially induced coal mining. It assumes mining all of the available coal reserves in Tract 2 of the Otter Creek Mine (beyond the permitted amounts) and all available reserves at the Poker Jim Creek–O’Dell Creek deposit beyond the previously permitted amounts. Table 3-8 shows the coal production, by year, and the associated number of trains per day under the high production scenarios.

Table 3-8. Northern Alternatives High Production Scenarios

Year	Otter Creek (Tract 2) (million tons per year)	Poker Jim Creek– O’Dell Creek (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per day
2018	20.4	–	20.4	7.6
2019	27.2	–	27.2	10.1
2020	34.0	–	34.0	12.6
2021	34.0	–	34.0	12.6
2022	34.0	–	34.0	12.6
2023	34.0	9.6	43.6	16.2
2024	34.0	12.8	46.8	17.4
2025	34.0	16.0	50.0	18.6
2026	34.0	16.0	50.0	18.6
2027	34.0	16.0	50.0	18.6
2028	34.0	16.0	50.0	18.6
2029	34.0	16.0	50.0	18.6
2030	34.0	16.0	50.0	18.6
2031	34.0	16.0	50.0	18.6
2032	34.0	16.0	50.0	18.6
2033	34.0	16.0	50.0	18.6
2034	34.0	16.0	50.0	18.6
2035	34.0	16.0	50.0	18.6
2036	34.0	16.0	50.0	18.6
2037	34.0	16.0	50.0	18.6

3.3.2 Southern Alternatives

The scenarios for the southern alternatives range from a low production of 20 million tons of coal per year corresponding to an average of 7.4 trains per day, to a high production of 72 million tons of coal per year corresponding to an average of 26.7 trains per day. These scenarios cover the Otter Creek Mine, Poker Jim Creek–O’Dell Creek deposit, and Canyon Creek deposit, which are of a relatively high quality based on the weighting factor scores for heat content, available coal reserves, overburden ratio, sulfur content, and distance.

3.3.2.1 Low Production

The low production scenarios for the southern alternatives (scenarios 12, 13, and 14) are based on the annual production rate of 20 million tons per year identified in the mine permit application for the Otter Creek Mine, Tract 2 (Montana Department of Environmental Quality 2012). Table 3-9 shows the coal production, by year, and the associated number of trains per day under the low production scenarios.

Table 3-9. Southern Alternatives Low Production Scenarios

Year	Otter Creek, Tract 2 (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per day
2018	12.0	12.0	4.5
2019	16.0	16.0	5.9
2020	20.0	20.0	7.4
2021	20.0	20.0	7.4
2022	20.0	20.0	7.4
2023	20.0	20.0	7.4
2024	20.0	20.0	7.4
2025	20.0	20.0	7.4
2026	20.0	20.0	7.4
2027	20.0	20.0	7.4
2028	20.0	20.0	7.4
2029	20.0	20.0	7.4
2030	20.0	20.0	7.4
2031	20.0	20.0	7.4
2032	20.0	20.0	7.4
2033	20.0	20.0	7.4
2034	20.0	20.0	7.4
2035	20.0	20.0	7.4
2036	20.0	20.0	7.4
2037	20.0	20.0	7.4

3.3.2.2 Medium Production

The medium production scenarios for the southern alternatives (scenarios 15, 16, and 17) are based on the production rate of 20 million tons per year identified in the mine permit application for the Otter Creek Mine, Tract 2 (Montana Department of Environmental Quality 2012). This scenario also includes the Poker Jim Creek–O’Dell Creek deposit at the previously permitted 12 million tons per year mining capacity, which is the maximum permitted production capacity (U.S. Department of the Interior 1984). Table 3-10 shows the coal production, by year, and the associated number of trains per day under the medium production scenarios.

Table 3-10. Southern Alternatives Medium Production Scenarios

Year	Otter Creek (Tract 2) (million tons per year)	Poker Jim Creek– O’Dell Creek (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per Day
2018	12.0	–	12.0	4.5
2019	16.0	–	16.0	5.9
2020	20.0	–	20.0	7.4
2021	20.0	–	20.0	7.4
2022	20.0	–	20.0	7.4
2023	20.0	7.2	27.2	10.1
2024	20.0	9.6	29.6	11.0
2025	20.0	12.0	32.0	11.9
2026	20.0	12.0	32.0	11.9
2027	20.0	12.0	32.0	11.9
2028	20.0	12.0	32.0	11.9
2029	20.0	12.0	32.0	11.9
2030	20.0	12.0	32.0	11.9
2031	20.0	12.0	32.0	11.9
2032	20.0	12.0	32.0	11.9
2033	20.0	12.0	32.0	11.9
2034	20.0	12.0	32.0	11.9
2035	20.0	12.0	32.0	11.9
2036	20.0	12.0	32.0	11.9
2037	20.0	12.0	32.0	11.9

3.3.2.3 High Production

For the high production scenarios for the southern alternatives (scenarios 18, 19, and 20) OEA expanded the analysis to include other areas of potentially induced coal mining. It assumes mining all of the available coal reserves in Tract 2 of the Otter Creek Mine (beyond the permitted amounts) and all available reserves at the Poker Jim Creek–O’Dell Creek deposit and Canyon Creek deposits. The high production scenario under the southern alternatives is the only scenario that includes the Canyon Creek deposit, which has not been included in other analyses of deposits, has not been permitted, and would only be accessible from the southern alternatives. The Canyon Creek deposit includes pieces of land for which both surface and mineral rights are owned by BLM or State of Montana as well as 3,000 acres of private land. The resulting area is approximately 23% of the entire deposit and has a production capacity of roughly 22 million tons per year. Table 3-11 shows the coal production, by year, and the associated number of trains per day under the high production scenarios.

Table 3-11. Southern Alternatives High Production Scenarios

Year	Otter Creek (Tract 2) (million tons per year)	Poker Jim Creek- O'Dell Creek (million tons per year)	Canyon Creek (million tons per year)	Total Coal Production (million tons per year)	Number of Trains per Day
2018	20.4	—	—	20.4	7.6
2019	27.2	—	—	27.2	10.1
2020	34.0	—	—	34.0	12.6
2021	34.0	—	—	34.0	12.6
2022	34.0	—	—	34.0	12.6
2023	34.0	9.6	—	43.6	16.2
2024	34.0	12.8	—	46.8	17.4
2025	34.0	16.0	—	50.0	18.6
2026	34.0	16.0	—	50.0	18.6
2027	34.0	16.0	—	50.0	18.6
2028	34.0	16.0	13.2	63.2	23.5
2029	34.0	16.0	17.6	67.6	25.1
2030	34.0	16.0	22.0	72.0	26.7
2031	34.0	16.0	22.0	72.0	26.7
2032	34.0	16.0	22.0	72.0	26.7
2033	34.0	16.0	22.0	72.0	26.7
2034	34.0	16.0	22.0	72.0	26.7
2035	34.0	16.0	22.0	72.0	26.7
2036	34.0	16.0	22.0	72.0	26.7
2037	34.0	16.0	22.0	72.0	26.7

3.4 Previous Proposed Actions for the Tongue River Railroad

The three previous EISs for Tongue River Railroad (Tongue River I, Tongue River II, and Tongue River III⁹) each approached the issue of potentially induced coal mining differently, with varying projections in coal volumes and numbers of trains, (Sections 3.4.1, *Tongue River I*, 3.4.2, *Tongue River II*, and 3.4.3, *Tongue River III*). OEA carefully reviewed the three analysis methods to provide background information on area coal deposits and potential production and transportation rates. The coal production scenarios were specific to each of

⁹ **Tongue River I:** Tongue River R.R.—Rail Constr. and Operation—In Custer, Powder River and Rosebud Cntys., Mont. (Tongue River I), FD 30186 (ICC served Sept. 4, 1985), modified (ICC served May 9, 1986), pet. for judicial review dismissed, N. Plains Res. Council v. ICC, 817 F.2d 758 (9th Cir.), cert. denied, 484 U.S. 976 (1987); **Tongue River II:** Tongue River R.R.—Rail Constr. and Operation—Ashland to Decker, Mont. (Tongue River II), 1 S.T.B. 809 (1996), pet. for reconsid. denied (STB served Dec. 31, 1996); **Tongue River III:** Tongue River R.R.—Rail Constr. and Operation—Ashland to Decker, Mont. (Tongue River III), FD 30186 (SubNo. 3) (STB served Oct. 9, 2007), pet. for reconsid. denied (STB served Mar. 13, 2008). N. Plains Res. Council v. STB, 668 F.3d 1067 (9th Cir. 2011)

the previous proposed actions and have been made obsolete by changes in the international coal market, domestic coal demand, land ownership, and current state and federal leasing options. Therefore, OEA did not incorporate coal production data from the previous EISs into this analysis. However, for context, Table 3-12 shows the coal production scenarios contained in this EIS compared to the three previous Tongue River EISs. The ranges of coal production levels analyzed in this Draft EIS encompass all of the production levels analyzed in the previous Tongue River Railroad EISs. The following three sections discuss the three prior Tongue River EISs.

Table 3-12. Comparison of Coal Production Rates for Tongue River Current and Prior EISs

	Maximum Production (millions of tons/year)	Trains per Day
Current Scenarios		
Northern alternatives – low production	20	7.4
Northern alternatives – medium production	32	11.9
Northern alternatives – high production	50	18.6
Southern alternatives – low production	20	7.4
Southern alternatives – medium production	32	11.9
Southern alternatives – high production	72	26.7
Scenarios from Previous Tongue River Railroad Proposed Actions^a		
Tongue River I	44.0	25.0
Tongue River II	39.0	18.0
Tongue River III ^b	36.8	14.0
Notes:		
^a The maximum coal production rates for the three previous proposed actions represent different potentially induced coal mines than those in OEA's current analysis.		
^b Tongue River III was a proposed rail line segment that was seen as a shortcut to transport coal north		

3.4.1 Tongue River I

The EIS for the Tongue River I proposed action was prepared in the early 1980s and analyzed an 89-mile rail line in Powder River, Custer, and Rosebud Counties, Montana.¹⁰ The rail line would have provided service to the proposed Montco Mine and other potential surface mines in the Ashland/Birney/Otter Creek area.

The Tongue River I EIS analyzed five potential mine sites (the Montco Mine and four other hypothetical mines) for which there were no mine plans or permit applications. These mine sites were identified using information from BLM's Final EIS on area coal reserves in 1981,

¹⁰ Tongue River R.R.—Rail Constr. and Operation—In Custer, Powder River and Rosebud Cntys., Mont. (Tongue River I), FD 30186 (ICC served Sept. 4, 1985), modified (ICC served May 9, 1986), pet. for judicial review dismissed, N. Plains Res. Council v. ICC, 817 F.2d 758 (9th Cir.), cert. denied, 484 U.S. 976 (1987).

from the Montana Department of State Lands data, and from data in TRRC reports (Bureau of Land Management 1981, Hayden and Lynch pers. comm.). The Tongue River I EIS estimated that 38 million tons of coal could be produced annually if all five mine sites, including the four hypothetical mines, operated at full capacity. OEA completed the analysis for three coal production scenarios: low, medium, and high (Table 3-13). OEA developed these production scenarios from information provided by Peat, Marwick, Mitchell and Company, Ernst and Whinney (TRRC consultants), the Montana Department of State Lands, and the Interstate Commerce Commission (now known as the Surface Transportation Board) (Bureau of Land Management 1981; Peat, Harwick, Mitchel 1981; Wheeler pers. comm.). OEA based the development schedule for the five mine sites on the proposed Montco Mine development schedule and an extrapolation of this schedule to the four hypothetical mines in the Ashland/Birney/Otter Creek area. OEA's current analysis looks at the coal deposit that composed the Montco Mine site, but does not look at the four other mine sites due to lack of data presented in the Tongue River I EIS to help identify these sites and determine the coal quality for this analysis.

Table 3-13. Tongue River I Coal Production Scenarios (million tons per year)

Year	Montco Mine	Mine 2	Mine 3	Mine 4	Mine 5	Total Coal Production	Trains per Day
Low Production Scenario							
1986	1					1	1
1991	6					6	4
1996	12	1				13	7
2001	12	6				18	10
2006		9	7	6		22	12
2011		9	8	8	8	33	19
Medium Production Scenario							
1986	1					1	1
1991	6					6	5
1996	13	3				15	8
2001	12	6	4	3		25	14
2006		10	10	8	3	31	18
2011		10	10	9	9	38	22
High Production Scenario							
1986	1					1	1
1991	6	3				9	7
1996	12	4				17	10
2001	12	12	6	2	2	34	19
2006		12	12	10	10	44	25
2011		12	12	10	10	44	25

3.4.2 Tongue River II

The EIS for the Tongue River II proposed action was prepared in the early 1990s and analyzed a 42-mile rail line from Ashland to Decker in Rosebud and Big Horn Counties, Montana.¹¹ The rail line would have extended from the planned 89-mile rail line between Miles City and Ashland previously authorized by the Interstate Commerce Commission to TRRC in 1985.

The Tongue River II EIS analyzed the Montco Mine, three existing mines (East Decker, West Decker, and Spring Creek), and the Wyoming Powder River Basin mines. The Tongue River II EIS included an analysis of Wyoming Powder River Basin mines in the event that the proposed rail line was used by BNSF to haul extra coal from the Gillette, Wyoming area as a transportation shortcut to the Midwestern electric utility plants. OEA developed the coal traffic projections in conjunction with the Interstate Commerce Commission's Section of Energy and Environment, the BLM, and the Montana Department of State Lands.¹² The Tongue River II EIS indicated that even though the sources of new coal production had changed from the Tongue River I EIS, the volume of coal traffic to be hauled on the entire TRRC line would have been generally the same as the medium scenario proposed in 1985. Table 3-14 shows the estimated coal production and trains per day for the Tongue River II proposed action.

Table 3-14. Tongue River II Coal Production Scenarios and Trains per Day

	Estimated Coal Production (million tons per year)				Trains per Day		
	Wyoming Mines	Existing Montana Mines	Near Mines ^a	Total	On the TRRC Extension	Originating from the Ashland- Area Mines	On the Entire <u>Tongue River II</u> Rail Line
1995/1996	3	12	2	17	8	2	10
2000	6	12	8	26	8	4	12
2005	6	15	10	31	10	4	14
2010	6	15	18	39	10	8	18

Notes:

^a Mines identified as being close to the previously proposed Tongue River II rail line

¹¹ Tongue River R.R.—Rail Constr. and Operation—Ashland to Decker, Mont. (Tongue River II), 1 S.T.B. 809 (1996), pet. for reconsid. denied (STB served Dec. 31, 1996).

¹² Tongue River R.R.—Rail Constr. and Operation—Ashland to Decker, Mont. (Tongue River II), 1 S.T.B. 809 (1996), pet. for reconsid. denied (STB served Dec. 31, 1996).

3.4.3 Tongue River III

The EIS for the Tongue River III proposed action was prepared in the early 2000s and analyzed a 17.3-mile rail line known as the Western Alignment.¹³ The Western Alignment would have been located in Rosebud and Big Horn Counties, Montana. The proposed Western Alignment was an alternative route for the southernmost portion of the previously planned 41-mile Ashland to Decker alignment approved under the Tongue River II EIS.

The Tongue River III EIS analyzed the Montco Mine, three existing mines (East Decker, West Decker, and Spring Creek), and three potential future mines (CX Ranch Mine, King Creek Mine, and Otter Creek Mine). TRRC stated that the proposed Tongue River III rail line would be used by both Wyoming and Decker-area coal mines and that, while no permit applications existed for the CX Ranch Mine, King Creek Mine, or the Otter Creek Mine at the time that Tongue River III was being developed, applications for these mines could have been submitted sometime in the future. Estimated coal production and tonnage by transportation route for the Tongue River III proposed action are shown in Table 3-15. The number of trains was estimated to be seven for the Proposed Western Alignment and seven for the Approved Four Mile Creek Alternative, based on 31.9 million tons of coal at 113 coal cars each able to carry an estimated 117 tons of coal, which equals 14 trains per day for both alternatives.

Table 3-15. Tongue River III Coal Production Scenarios (million tons per year)

Year	Origin			Total Coal Carried by TRRC to Miles City	Total Coal Carried over Proposed Western Alignment (Excludes Ashland Area Coal)
	Wyoming Coal	Decker Area Coal	Ashland Area Coal		
2009	16.6	15.3	0.3	32.2	31.9
2014	12.2	12.3	12.3	36.8	24.5
2019	12.2	12.3	12.3	36.8	24.5

¹³ Tongue River R.R.—Rail Constr. and Operation—Ashland to Decker, Mont. (Tongue River III), FD 30186 (Sub-No. 3) (STB served Oct. 9, 2007), pet. for reconsid. denied (STB served Mar. 13, 2008), N. Plains Res. Council v. STB, 668 F.3d 1067 (9th Cir. 2011)

Proposed Coal Export Terminals and Expansions

4.1 Introduction

OEA developed assumptions regarding terminal capacity for coal export from the Pacific Northwest. The main operating coal export terminals on the west coast are in Vancouver, and Prince Rupert (British Columbia, Canada). These terminals have limited capacity for additional overseas export of U.S. coal in spite of recently completed and proposed capacity expansions. Existing coal traffic already consumes most of the Canadian terminal capacity (Westshore Terminals 2013). Increased coal terminal capacity in the United States or Canada is foreseeable because companies such as Teck Coal, Millennium Bulk Terminals-Longview LLC, and SSA Marine have recently proposed several new terminals for construction in these areas. However, uncertainty remains on the locations and the extent of this growth in capacity.

This chapter includes a description of coal export terminals in the Pacific Northwest and evaluations of export routing, terminal capacity, and export capacity.

4.2 Coal Export Terminals in the Pacific Northwest

There are three existing terminals and four proposed terminals in the Pacific Northwest through which Powder River Basin coal could be exported. The existing coal export terminals are in British Columbia, Canada, and include Westshore Terminal, Neptune Terminal, and Ridley Terminal. The Westshore and Neptune Terminals are located near Vancouver, while the Ridley Terminal is located at Prince Rupert, which is approximately 1,400 rail miles north of Vancouver.

- **Westshore Terminal.** The Westshore Terminal is located at Roberts Bank, British Columbia, less than 1 mile north of the U.S. border. The BNSF Railway Company (BNSF), Canadian Pacific (CP), and Canadian National (CN) railroads serve this terminal (Figure 4-1). Westshore is one of the largest coal export terminals in North America and serves both Canadian and U.S. coal producers.
- **Neptune Terminal.** The Neptune Terminal is owned by Canadian coal company Teck Coal and is served by the BNSF, CP, and CN railroads. Neptune recently completed an expansion of its export capacity to 13.8 million tons per year. Teck Coal plans to expand the Neptune Terminal capacity by an additional 6.6 million tons per year, although the timing of this expansion remains uncertain.

Figure 4-1. Westshore Terminal



Source: Canadian Ministry of Energy, Mines, and Petroleum Resources 2010

- **Ridley Terminal.** The Ridley Terminal is located in Prince Rupert, British Columbia, and is served by the CN railroad. Ridley Terminal primarily handles coal from mines in northern British Columbia, although a few million tons of coal from the Powder River Basin have been shipped through this terminal in recent years. Several Powder River Basin coal producers, such as Arch Coal and Cloud Peak Energy, recently signed 5-year contracts to ship coal through Ridley Terminal. The contracts expire in 2015 and the government-owned terminal is expected to handle only Canadian coal from 2015 onward (Arch Coal 2011, de Place and MacRae 2012).¹ It is also significantly more expensive to ship Powder River Basin coal through Ridley Terminal compared to current or proposed terminals in Washington, Oregon, or Vancouver, British Columbia. Despite having 10% shorter shipping distance to the Pacific Basin, Ridley Terminal has rail distance that is about 100% longer than other terminals.² At current rail and shipping costs, the overall transportation cost from the Powder River Basin to Asia is higher through Ridley Terminal than through the Westshore Terminal.

¹ Arch Coal's agreement with Ridley Terminal to export up to 2.5 million metric tons per year through 2015.

² Cloud Peak states that the rail distance from their Powder River Basin mines to Ridley is over 2,600 miles and can require up to three different rail carriers (Cloud Peak Energy 2013).

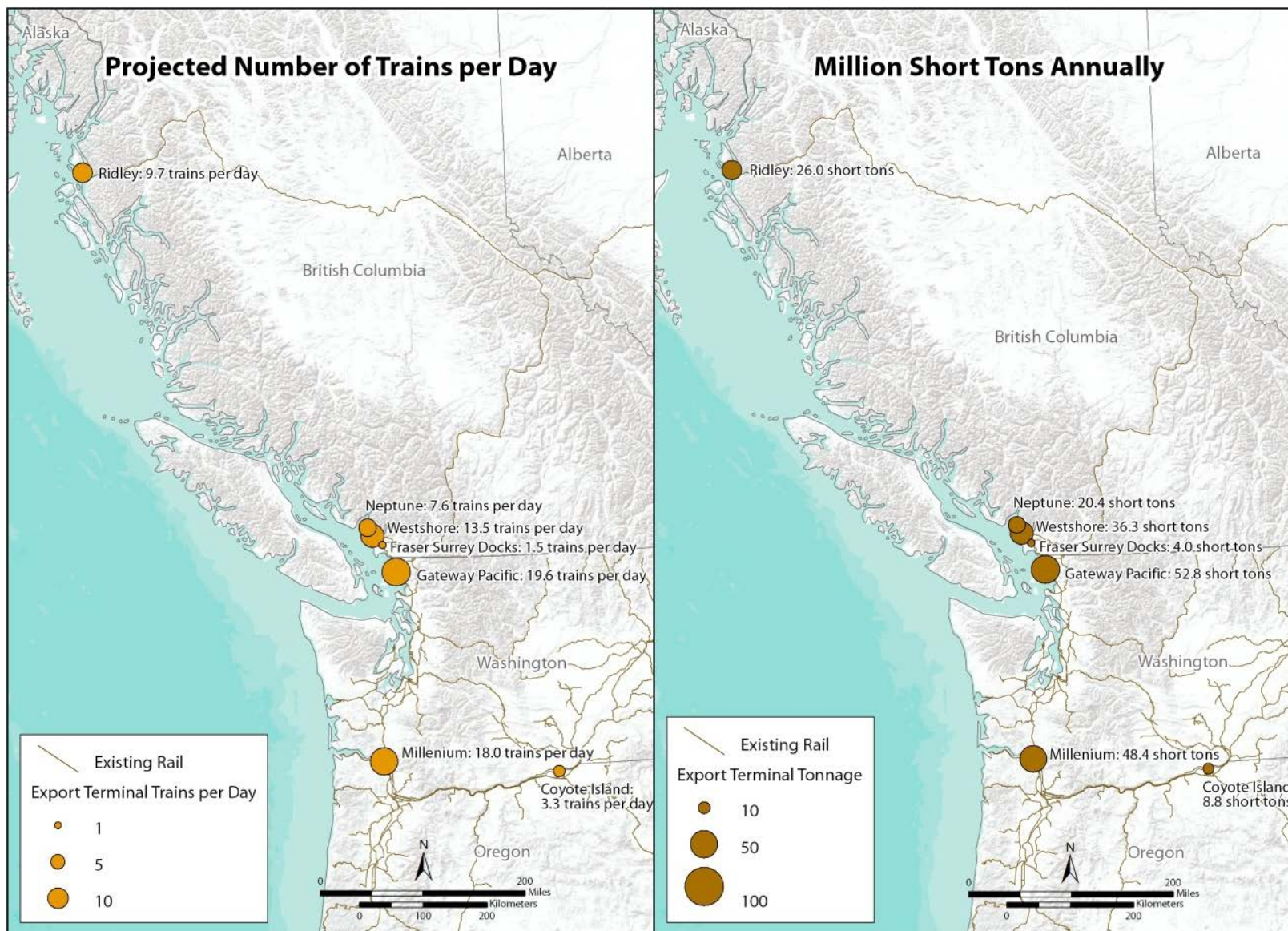
Four new coal export terminals are proposed in Washington, Oregon, and British Columbia and could provide additional capacity for Powder River Basin coal exports. Figure 4-2 shows the export capacities of these terminals and the corresponding number of trains arriving daily.

Three of the proposed terminal projects are in Washington and Oregon.

- **Gateway Pacific Terminal.** The proposed Gateway Pacific Terminal at Cherry Point, Washington, would handle bulk commodities such as coal. The terminal is served by BNSF. One advantage of this terminal is that it could load capesize vessels, which provide a cost advantage over smaller Panamax vessels.³
- **Millennium Bulk Terminal.** The Millennium Bulk Terminal at Longview, Washington is an existing terminal on the Columbia River. Plans include adding infrastructure to unload coal from trains and move it to storage and then to ships. The terminal is served by BNSF and UP railroads. The terminal can load up to Panamax size vessels, with no plans to modify the port to handle larger vessels.
- **Coyote Island Terminal.** The Coyote Island Terminal at Morrow, Boardman, Oregon, would be located on the Columbia River. This terminal would be served by the BNSF railroad. Coal coming to this terminal would be barged by the shipper down the Columbia River to the Port Westward Industrial Park in Oregon and transloaded onto Panamax vessels. On August 18, 2014, the Oregon Department of State Lands denied the removal-fill permit for the Coyote Island Terminal at the Port of Morrow in Boardman, Oregon. The applicant, Ambre Energy, has appealed the decision (Oregon Department of State Lands 2014). Since the permit denial and appeal occurred after the modeling had been done for this analysis, the Coyote Island Terminal is included in the high terminal growth scenarios.
- **Fraser Surrey Docks.** Fraser Surrey Docks, at Vancouver, British Columbia, has applied for a permit to construct a coal transfer facility of 4 million tons per year of capacity and has announced plans to potentially ramp up capacity to 8 million tons per year. BNSF would serve this facility. On August 21, 2014, Port Metro Vancouver granted a Project Permit for the terminal's Direct Coal Transfer Project, which is scheduled to begin operation late in 2015 (Port Metro Vancouver 2014).

³ *Capesize* vessels are cargo ships capable of carrying approximately 150,000 metric tons. *Panamax* vessels are smaller and can carry approximately 75,000 metric tons. The Gateway Pacific Terminal would be able to load the larger, capesize vessels because of its deeper waters.

Figure 4-2. Pacific Northwest Terminal Expansion Projects



4.3 Export Routing

OEA evaluated the potential routing of Tongue River coal exports, as well as the existing and potential Pacific Northwest terminal capacity. OEA also evaluated the economics of each movement to identify the most likely export options to be included in the analysis model. The potential destinations were ports in the Great Lakes, Gulf Coast, Pacific Northwest, and on the eastern seaboard. Specifically, OEA considered the following six routes.

- Routes to proposed Pacific Northwest terminals.
- Routes to Ridley Terminal, Prince Rupert, British Columbia.
- Routes to the Great Lakes via Superior, Wisconsin Terminal.
- Routes to the eastern seaboard via terminals in Norfolk or Newport News, Virginia.
- Routes to New Orleans, Louisiana via rail-barge movements.
- Routes to the Texas Gulf Coast.

As described in Chapter 9, *Rail Transportation Routes*, OEA found that the Pacific Northwest routes, except for Ridley Terminal, would be economically viable export routes for Otter Creek coal specifically, and Tongue River coal in general. Table 4-1 summarizes the considerations for each of the possible routes for Tongue River coal and the likelihood of an increase in rail traffic.

Table 4-1. Domestic Movement and Export Routing Considerations

From Tongue River and other Powder River Basin Sources to Potential Destinations	Criteria for Environmental Review
Domestic Movements	Because domestic coal demand is declining, any market share captured by Otter Creek or Tongue River coal would largely be offset by declines in other Powder River Basin coal deliveries. No net gain in rail traffic is estimated for domestic movements; there may be changes in rail traffic on specific domestic rail transportation routes.
Pacific Northwest, except Prince Rupert, BC	Pacific Northwest terminals are the most likely destinations for Powder River Basin exports to Asia. Export via the Pacific Northwest would generate incremental traffic spread over multiple routes.
Prince Rupert, BC	Much longer rail distances (1,400 miles further than Vancouver terminals) would make Ridley Terminals in Prince Rupert uncompetitive with other Pacific Northwest terminals. ^a No net gain in rail traffic is estimated for this route.
Great Lakes via Superior, WI	Long rail transport distances, limited vessel draft, and high costs for multiple handling points for the coal limit the competitiveness of this route for export. No net gain in rail traffic is estimated for this route.
New Orleans and Texas—U.S. Gulf Coast	Otter Creek and Tongue River coal originating in Montana would be about 246 miles further than Wyoming Powder River Basin coal, making it difficult to compete for Gulf Coast shipments, but exporting Wyoming Powder River Basin coal through the Gulf Coast to Asia may be competitive. Transportation routes could include both BNSF and UP lines to export terminals such as the Port Arthur in Texas. No net gain in traffic is estimated for this route. Tongue River coal would face higher rail and ocean vessel costs than for competing Wyoming Powder River Basin coal.
Lamberts Point, VA—U.S. East Coast	Much longer rail transport distances and movements involving two railroads would not be competitive with Pacific Northwest routes for Powder River Basin coal export to Asia, or with Appalachian coal for export to Europe. No net gain in traffic is estimated for this route.

Notes:

- ^a When Asian pricing peaked and there was no capacity available at the Westshore Terminals in British Columbia, Canada, Arch Coal and Cloud Peak Energy entered into contracts to export coal through the Ridley Terminal in Prince Rupert, Canada. Because of the scarcity of loading capacity, Ridley Terminal was able to get the producers to sign take-or-pay contracts, meaning that the producers had to pay for transloading certain minimum coal quantities, even if they did not actually ship the coal. Because of the take-or-pay provisions, some shipments continued even after the amounts that the producers were receiving for their coal (netback) was less than the cost of the coal. This occurred because the transloading costs for the minimum tonnage had to be paid even if the coal was not shipped (a sunk cost). In that case, the producer might be better off shipping coal even at a slight loss than not shipping at all. Asian prices are forecast to be low enough that future movements of Powder River Basin coal to the Pacific Basin through the Ridley Terminal would not be economical.

Tables 4-2 and 4-3 show the details of the cost calculations for transporting coal to Japan from the Powder River Basin through the two most economically viable options, which are the Pacific Northwest terminals and U.S. Gulf Coast terminals. This analysis focuses on the Pacific Basin because it is the fastest growing market for steam coals, and Japan is an example of a Pacific Basin movement (Chapter 2, *Historical Powder River Basin Production and Markets*). OEA selected Japan to illustrate the total transportation costs, because it has historically imported more coal than any other Pacific Basin country, and is one possible destination for Powder River Basin coal exports. Powder River Basin coal exports to other countries, such as China, Korea, or Taiwan, would be similar, except that the shipping distances would be longer by 130 to 1,500 miles. Movement of Tongue River coal through the Pacific Northwest to Japan would cost less than via the Gulf Coast to Japan. Furthermore, movement through the Gulf Coast is less costly for Wyoming coals than for Montana Coals (Table 4-2), such as Tongue River coal.

The existing and proposed Pacific Northwest terminals, not including Ridley Terminal, have the following advantages and characteristics.

- **Shortest export route to Asia.** Shipping distances to Japan from the Pacific Northwest are approximately half the distance from the U.S. Gulf Coast.
- **Lowest-cost export.** There is an ocean freight cost advantage to Asia via the Pacific Northwest. Powder River Basin shipments from four Powder River Basin subregions, including Tongue River, averaged approximately \$51 per ton (\$2.92 per million British thermal units [MMBtu]), and ranged from \$50 per ton to \$52 per ton. In contrast, costs averaged \$64 per ton for Gulf Coast shipment to Japan (\$3.63 per MMBtu), and ranged from \$61 per ton to \$68 per ton. If Powder River Basin coal costs \$12 per ton at the mine, then total delivered costs could be as low as from \$3.35 per MMBtu to \$3.81 per MMBtu for shipments from Pacific Northwest terminals. This is similar to recent prices in Japan and elsewhere in the Pacific Basin. In contrast, total delivered costs via the U.S. Gulf Coast range from \$4.08 per MMBtu to \$4.67 per MMBtu.
- **Historically used for Powder River Basin shipments.** Historically, Powder River Basin exports have been shipped primarily via Pacific Northwest terminals, supporting the conclusion that this export route is most economical for Montana Powder River Basin coals (Chapter 2, *Historical Powder River Basin Production and Markets*, and Chapter 9, *Rail Transportation Routes*).
- **Competitive advantage for Tongue River coal.** Export through the Pacific Northwest terminals would provide Tongue River coal with a rail cost advantage over Wyoming Powder River Basin coal. Montana Powder River Basin rail costs to the Pacific Northwest are about \$2 per ton lower than Wyoming Powder River costs. In contrast, Montana Powder River Basin rail costs to the Gulf Coast are about \$7 per ton higher than Wyoming Powder River Basin costs.

Table 4-2. Powder River Basin Rail and Ship Export Costs: Pacific Northwest and Gulf Coast Comparison

Powder River Basin Export Routes	Port	Rail Distance (miles)^a	Rail Rate with fuel surcharge (\$/ton-mile)	Total Rail Cost^b	Ship Distance (nautical miles)	Ship Rate (\$/ton-nautical mile)	Total Ship Cost via Panamax (\$/ton)^c	Port Fee (\$/ton)	Total Transportation Cost (\$/ton)
Tongue River to Japan via PNW	PNW	1,352	\$0.017	\$24.45	4,273	\$0.0031	\$14.75	\$11.00	\$50.20
Existing Montana to Japan via PNW	PNW	1,357	\$0.017	\$24.54	4,273	\$0.0031	\$14.75	\$11.00	\$50.29
Wyoming 8400 Btu/lb to Japan via PNW	PNW	1,457	\$0.017	\$26.23	4,273	\$0.0031	\$14.75	\$11.00	\$51.98
Wyoming 8800 Btu/lb to Japan via PNW	PNW	1,483	\$0.017	\$26.67	4,273	\$0.0031	\$14.75	\$11.00	\$52.42
Tongue River to Japan via Gulf Coast	Gulf Coast	1,882	\$0.017	\$33.45	9,178	\$0.0027	\$26.28	\$8.60	\$68.33
Existing Montana to Japan via Gulf Coast	Gulf Coast	1,616	\$0.017	\$28.94	9,178	\$0.0027	\$26.28	\$8.60	\$63.82
Wyoming 8400 to Japan via Gulf Coast	Gulf Coast	1,482	\$0.017	\$26.66	9,178	\$0.0027	\$26.28	\$8.60	\$61.54
Wyoming 8800 to Japan via Gulf Coast	Gulf Coast	1,456	\$0.017	\$26.22	9,178	\$0.0027	\$26.28	\$8.60	\$61.10

Notes:

^a Rail distances for the northern alternatives

^b Includes fixed rail cost of \$1.50/ton

^c Includes transfer cost of \$1.50/ton

PNW = Pacific Northwest; Btu/lb = British thermal units per pound

Table 4-3. Powder River Basin Delivered Coal Costs: Pacific Northwest and Gulf Coast Comparison

Powder River Basin Export Routes	Total Transportation Cost (\$/ton)	Illustrative Minemouth Price (\$/ton)^a	Total Delivered Cost (\$/ton)	Heat Content (MMBtu/ton)	Delivered Cost to Japan (\$/MMBtu)
Tongue River to Japan via PNW terminals	\$50.20	\$12.00	\$62.20	17.2 ^b	\$3.62
Existing Montana to Japan via PNW terminals	\$50.29	\$12.00	\$62.29	18.6 ^c	\$3.35
Wyoming 8400 Btu/lb to Japan via PNW terminals	\$51.98	\$12.00	\$63.98	16.8	\$3.81
Wyoming 8800 Btu/lb to Japan via PNW terminals	\$52.42	\$12.00	\$64.42	17.6	\$3.66
Tongue River to Japan via Gulf Coast terminals	\$68.33	\$12.00	\$80.33	17.2 ^b	\$4.67
Existing Montana to Japan via Gulf Coast terminals	\$63.82	\$12.00	\$75.82	18.6 ^c	\$4.08
Wyoming 8400 to Japan via Gulf Coast terminals	\$61.54	\$12.00	\$73.54	16.8	\$4.38
Wyoming 8800 to Japan via Gulf Coast terminals	\$61.10	\$12.00	\$73.10	17.6	\$4.15

Notes:

^a Actual minemouth prices will differ by year for the various Powder River Basin coals; \$12/ton approximates current Powder River Basin coal prices.

^b Otter Creek heat content = 8,600 Btu/lb; this is taken as the illustrative Tongue River coal's heat content.

^c Spring Creek heat content = 9,300 Btu/lb; this is taken as the illustrative existing Montana coal's heat content.

MMBtu = million British thermal units; PNW = Pacific Northwest, Btu = British thermal units

The cost estimates assume Gulf Coast movements are via Panamax vessels, which can carry 75,000 tons of coal. If the ship size is increased from Panamax to mini-capesize⁴ after the planned expansion of the Panama Canal by 2015, costs per ton to Japan from the Gulf Coast could decrease by \$7/ton. However, costs could also be lower than estimated between the Pacific Northwest and Japan portion of the movement if the draft from Gateway Pacific Terminal and other proposed Pacific Northwest terminals can accommodate ships larger than Panamax vessels. Thus, the cost advantage of the Pacific Northwest over the Gulf Coast might lessen with the use of ships larger than Panamax vessels, but it would not be eliminated. In addition, a decrease of \$7 per ton would not make the Gulf Coast route competitive with the Pacific Northwest route, even if the cost for Pacific Northwest ports stayed the same.

Lastly, as Table 4-3 shows, the delivered costs to Japan via the existing and proposed Pacific Northwest terminals are similar for all four Powder River Basin coals (Tongue River coal, Montana coal, Wyoming 8400 coal, and Wyoming 8800 coal; see Section 2.2.1, *Coal Types*). Relatively small changes in production costs or parts of the transportation cost could affect the export prospects of any of the Powder River Basin coals. It may be more economical to export certain Powder River Basin coals to the Pacific Basin and others to domestic

⁴ Mini-capesize vessels carry between 85,000 and 120,000 tons.

locations, as determined by the variables of location, markets, transportation facilities, and heat content of the coal (Chapter 9, *Rail Transportation Routes* and Chapter 8, *Coal Production and Transportation Modeling Results*).

4.4 Terminal Capacity

The three existing export terminals in the Pacific Northwest have limited capacity for additional Powder River Basin coal, as most of the terminal capacity is dedicated to the export of Canadian coal and existing contracts for export of U.S. coal. In addition, the long distance to the Ridley Terminal makes the use of this terminal less economical. Table 4-4 shows the expected capacity for Powder River Basin coal at each existing and proposed export terminal.

Table 4-4. Export Terminal Capacity (million tons per year)

Terminal	Total Existing Coal Export Capacity	Total Proposed Expansion or New Coal Export Capacity	Estimated Capacity Available for total Powder River Basin Coal Export
Existing Terminals			
Westshore, BC	36.3		6 to 12
Neptune, BC	13.8		2 to 6
Ridley, BC	13.2 +		0 to 4
Subtotal	63.3		8 to 22 ^a
Proposed Terminals			
Gateway Pacific, WA		52.8	52.8
Millennium Bulk, WA		48.4	48.4
Coyote Island, OR		8.8	8.8
Fraser Surrey Docks, BC		4 to 8 ^b	4
Subtotal		114	114
Total		133.8	122 to 136
Notes:			
^a 8 million tons per year of exports from Westshore and Neptune assumed in the zero terminal capacity growth case for U.S. producers (Chapter 1). The rest is assumed to be available for Canadian coal.			
^b Fraser Surrey Docks is in the permitting review process for the 4 million tons per year with the Port of Vancouver, Canada. They have announced plans for a total of 8 million tons per year of potential export capacity; however, this expansion would require an additional permit is not included as part of their proposed action (Fraser Surrey Docks 2013).			

Either there is not enough terminal capacity to export all of the Otter Creek coal or it is not economically feasible due to the distance from the mine (for example, Ridley Terminal). While some of the Otter Creek coal could be exported through existing terminal capacity, it would be competing for terminal space with other coals. If some or all of the proposed terminals were constructed, there would be sufficient terminal capacity to export all of the Otter Creek coal, as well as other Tongue River coal. Regardless of the extent of new Pacific Northwest terminal capacity, the proposed rail line would not lead to a net increase in tons of coal exported.

4.5 Export Capacity

OEA examined the capacity of Pacific Northwest terminals to export from 8 to 122 million tons per year of Powder River Basin coal, see zero, medium, and high growth sections below. Table 4-5 shows the terminal capacity in the Pacific Northwest for three different terminal capacity growth cases. Terminal capacity growth is one of the variables on which the analysis of the coal production and rail transportation scenarios is based, as described in Chapter 7, *Scenarios*.

Table 4-5. Terminal Capacity Growth (million tons per year)

Year	Terminal Capacity Growth ^a		
	Zero ^b	Medium	High
2018	8	32.5	65
2023	8	61	122
2030	8	61	122
2037	8	61	122

Notes:

^a Export capacity potentially available to Powder River Basin coal, including Tongue River coal.

^b Recent levels of Powder River Basin exports at 8 million tons per year remain constant.

- Zero growth.**⁵ The zero growth case assumes that only 8 million tons per year of export capacity is available to U.S. coal producers. This represents the existing Pacific Northwest terminal capacity available for U.S. coal, and assumes that terminal capacity would not be expanded. This is based on estimated 2012 exports of Powder River Basin coal via Vancouver of 6.7 million tons per year (Westshore and Ridley Terminals, Table 4-4), and a share of the recently completed expansion of Neptune Terminal. While the zero growth case is unlikely because there are multiple proposals to expand terminal capacity, OEA evaluated this case to address whether development of Tongue River coal would still be economically viable in the absence of terminal capacity growth.
- Medium growth.** The medium growth case assumes an incremental increase in capacity of 24.5 million tons per year by 2018 and 53 million tons per year by 2023, or about half of the capacity expected in the high growth case, based on permitting and development uncertainties. This yields 32.5 million tons per year of total export terminal capacity by 2018 and 61 million tons per year of total export terminal capacity by 2023. The case assumes the completion of one of the proposed coal export terminals in the Pacific Northwest, and the total coal export capacity available to U.S. producers is assumed to reach 61 million tons per year.
- High growth.** The high growth case is based on the completion of all of the proposed new coal export terminals in the Pacific Northwest. The high growth case assumes an incremental increase in capacity of 65 million tons per year by 2018 and 122 million tons

⁵ The terms *zero*, *medium*, and *high growth* are abbreviations for *zero*, *medium*, and *high terminal capacity growth*.

per year by 2023. The 122 million tons per year assumes construction of all four⁶ proposed terminals (114 million tons per year shown in Table 4-4, and 8 million tons per year in the zero growth case). Powder River Basin coal in general is assumed to occupy all of the coal exporting capacity as it holds rail distance advantages over other domestic bituminous coals and heat content as well as a rail distance advantage over other domestic lignite coals.

⁶ Includes Gateway Pacific Terminal, Millennium Bulk Terminal, Coyote Island Terminal, and Fraser Surrey Docks.

Model Framework, Methods, and Key Assumptions

5.1 Introduction

OEA used IPM[®] to assess likely coal production, rail traffic, and distribution patterns resulting from development of the Tongue River Railroad. OEA also examined the impacts of economic and regulatory uncertainties on these outcomes, focusing on low natural gas prices and potential federal carbon dioxide (CO₂) emission regulations.

The issues associated with assessing impacts of the Tongue River Railroad are complex and require a multifaceted computer-modeling platform. OEA used IPM[®] because no other available model endogenously (i.e., within one computer run) addresses so many factors affecting Tongue River Railroad coal production and rail traffic potential. OEA analyzed the impacts of all the coal production and distribution alternatives discussed in this appendix, even where IPM[®] found that the Tongue River coal production potential would not be economically viable.

This chapter provides an overview of the IPM[®] framework, the key assumptions OEA made when running the model, and the specific methods OEA used in its analysis.

5.2 Model Framework

5.2.1 IPM[®] Overview

IPM[®] is an engineering and economic model of the coal and power sectors, supported by an extensive database of coal and power parameters. The model has the ability to add new electricity-generating capacity in response to demand growth and policies, such as renewable portfolio standards. It is widely used to assess coal production, transportation, and consumption, and the operations and economics of the U.S. electric power industry. The model also characterizes the U.S. natural gas industry. IPM[®] is a multiregional model in terms of electricity demand regions, fuel demand regions, and coal supply regions that provides detailed results on a plant, regional, or national level.

ICF International has maintained IPM[®] since the mid-1970s. Users of the model include the U.S. Environmental Protection Agency (USEPA), other government agencies, nongovernment organizations, and private-sector companies.

IPM[®] simultaneously analyzes the following energy sectors and the important interactions between them (Figure 5-1).

- The coal mining industry, including regional coal mine type and coal quality distinctions.

- The rail and other coal transportation sectors.
- The electric power generation sector, including regional and power-plant-type distinctions, and very detailed treatment of existing power plants, especially coal-fired units.
- The electricity consumption portion of the business, including hourly and seasonal variations in demand.
- The electricity transmission sectors and the alternatives available to local power production.
- Environmental regulations (national and state) affecting the power sector including CO₂ emission limitations and renewable portfolio standards. The model also calculates emissions for each individual plant.
- Investment and long-term operational decisions such as coal power plant retirement, power plant mothballing, new power plant construction, existing coal mine operation, and new coal mine additions.
- Domestic and international coal sales.
- Interactions with the natural gas industry.

Figure 5-1. Integrated Planning Model (IPM®)



IPM® analyzes these markets and calculates competitive market prices based on supply and demand fundamentals. It forecasts the following wide range of parameters.

- Wholesale market power prices for each electricity demand region.
- Power plant dispatch.
- Fuel consumption and prices.
- Interregional transmission flows.
- Environmental emissions and associated costs.
- Capacity expansion and retirements.
- Retrofits based on an analysis of the engineering economic fundamentals.

The model does not extrapolate from historical conditions. Rather, it provides a least-cost forecast for a given set of current and future conditions that determine how the industry will function. The optimization routine that IPM[®] uses has dynamic effects—it looks ahead at future years and simultaneously evaluates decisions over an entire specified time horizon, typically 20 to 40 years.

IPM[®] uses a dynamic linear programming structure to model how electricity demand is met through a mix of generation and transmission in each region, as well as the transmission between regions. The North American version¹ of IPM[®] is divided into roughly 110 power demand regions, including eight Canadian provinces. The model uses 27 coal demand and 25 coal supply regions to forecast global coal production and movement.

5.2.1.1 Simplified IPM[®] Examples

IPM[®] seeks to minimize coal market costs as well as electric power sector costs. The calculations the model performs are simple in nature; however, a complex modeling platform is required because many calculations are performed simultaneously. This complexity stems from a detailed treatment of global coal markets and the U.S. electric power sector.

This section presents four examples of increasing complexity in a series of text boxes to facilitate the understanding of IPM's cost-minimizing method. Generally, fuel costs are compared on a dollar/million metric British thermal unit (\$/MMBtu) basis (minemouth cost + transportation cost)/heat content = delivered cost on an equivalent energy basis [\$/MMBtu]).

¹ ICF International has completed IPM[®] systems for Europe, Australia, Japan, China, Korea and India, among other nations.

Example 1. Minemouth and Transportation Costs

Example 1 shows two coal mines, A and B, that deliver coal to coal Plant 1. The table below shows the assumptions for heat content of the mined coal, minemouth cost, transportation cost to Plant 1 and the delivered costs in dollars per ton (\$/ton) and \$/MMBtu. The heat content and transportation costs are the same for both mines, but Mine B has higher production costs. IPM® will deliver coal from Mine A to Plant 1 for consumption because it is the least-cost option.

Coal Mine	Coal Heat Content (MMBtu/ton)	Minemouth Cost (\$/ton)	Transportation Cost to Plant 1 (\$/ton)	Delivered Cost (\$/ton)	Delivered Cost (\$/MMBtu)
A	20	15	25	40	2.00
B	20	25	25	50	2.50

Example 2. Heat Content

Example 2 is the same as Example 1, except the heat content of the coal from Mine B is higher. The table below shows the Example 2 assumptions. Since Mine B has lower delivered costs on a \$/MMBtu basis, IPM® delivers coal from Mine B to Plant 1.

Coal Mine	Heat Content of Coal (MMBtu/ton)	Minemouth Cost (\$/ton)	Transportation Cost to Plant 1 (\$/ton)	Delivered Cost (\$/ton)	Delivered Cost (\$/MMBtu)
A	20	15	25	40	2.00
B	26	25	25	50	1.92

Example 3. Coal versus Gas

Example 3 is the same as Example 1, except the electric demand region now has a natural-gas-fired plant as well as a coal-fired plant, and the mines have production capacities. The table below shows the Example 3 assumptions. Both the coal and gas plants compete to serve the same regional energy demand of 7,000 gigawatt hours. IPM® dispatches the coal or gas plant based on the cost of generation (\$/MWh), which is driven by the fuel cost of generation. Assuming a gas price of \$3.5/MMBtu, IPM® dispatches the coal power plant, which consumes the 2 million tons from Mine A, then dispatches the natural gas plant, and finally dispatches the coal plant again using 0.5 million tons from Mine B. Total coal consumption is 2.5 million tons. If gas prices increase to \$3.58/MMBtu or above, or the minemouth cost of coal from Mine B drops from \$25/ton to below \$24/ton, the coal and gas equilibrium shifts, and the gas plant does not dispatch because its cost of generation is higher than the coal plant's.

Coal versus Gas Assumptions

Coal Mine	Annual Production Capacity (million tons)	Heat Content of Coal (MMBtu/ton)	Minemouth Cost (\$/ton)	Transportation Cost to Coal Plant (\$/ton)	Delivered Cost (\$/ton)	Delivered Cost (\$/MMBtu)
A	2	20	15	25	40	2.00
B	5	20	25	25	50	2.50

Cost of Generation

Power Plant	Maximum Annual Generation (GWh)	Delivered Cost of Fuel (\$/MMBtu)	Plant Heat Rate (Btu/kWh)	Fuel Cost of Generation (\$/MWh)
1 – Coal, Mine A	4,000	2.00	10,000	20.0
1 – Coal, Mine B	10,000	2.50	10,000	25.0
2 – Natural gas	2,000	3.50	7,000	24.5

GWh = gigawatt hours; Btu/kWh = British thermal units per kilowatt hour; \$/MWh = dollars per megawatt hour

Example 4. New Coal Mine and Displacement

Example 4 has the same assumptions as Example 3; however, the expected coal displacement is calculated when a new mine, C, is brought online. The table below shows the Example 4 assumptions.

A scenario with new Mine C that has a lower delivered cost than Mine B results in IPM® using the coal from Mine C instead of Mine B, essentially displacing Mine B coal with coal from Mine C. Since the heat content of the coal from Mine C is lower than Mine B, the total coal consumption increases slightly to 2.56 million tons. However, if the minemouth cost of coal from Mine C was below \$20/ton, resulting in a delivered cost of \$2.44/MMBtu, then IPM® would not dispatch the natural gas plant and only dispatch the coal plant using coal from Mine A and Mine C, which would result in total coal consumption increasing to 3.6 million tons.

Coal Displacement

Coal Mine	Annual Production Capacity (million tons)	Heat Content of Coal (MMBtu/ton)	Minemouth Cost (\$/ton)	Transportation Cost to Coal Plant (\$/ton)	Delivered Cost (\$/ton)	Delivered Cost (\$/MMBtu)
A	2	20	15	25	40.0	2.00
B	5	20	25	25	50.0	2.50
C	2	18	20.3	24	44.3	2.48

By using IPM®'s single framework, all parameters are solved for simultaneously; therefore, the impacts of changes in one parameter affect all other related factors. For example, the addition of a CO₂ policy results in increased natural gas demand and prices, and, depending on the extent of the increase, lower coal demand and prices. In addition, the model is able to simultaneously represent the demand response to higher power prices because of a CO₂ policy, and represent federal and state renewable portfolio standards. Thus, the model provides a way to develop a foreseeable, integrated, and accurate long-term forecast.

5.2.2 IPM® Users and Public Documentation

5.2.2.1 Uses and Users

IPM® is widely used, both in the United States and globally, by private sector companies such as electric utilities, coal power plant owners, coal companies, independent power producers, and financial institutions, and public sector entities, such as environmental groups and state public service commissions (Table 5-1).

Table 5-1. Private and Public Sector Entities Using IPM®

Private Sector Entities	Public Sector Entities
PEPCO	U.S. Environmental Protection Agency
Entergy	State public service commissions
Exelon	Environment Canada
Tucson Electric Power	European Union
Florida Power and Light (FPL)	Environmental groups (e.g., Natural Resources Defense Council)
Dominion	
NRG	
Delmarva Power	
Southwestern Electric Power Company	
Calpine	
APS	
Duke Energy	
American Electric Power	
Otter Tail Power Company	
Xcel Energy	
Dogwood Energy	
Peabody Energy	
Dynegy	

IPM® has been used in support of the following types of analyses.

- Coal price forecasts, including forecasts supporting litigation.
- Other coal industry forecasts, including production, transportation, and consumption.
- Air emissions compliance strategies for coal power plants and emission allowance price forecasting.
- Impact assessments of alternate environmental regulatory standards including coal sector impacts.
- Assessments of power plant retirement decisions, such as for existing coal power plants.
- Valuation studies for generation and transmission assets, including coal power plant valuations.
- Forecasting of regional forward energy and capacity prices.
- Forecasting of state and regional renewable energy credits.
- Impact assessments of changes in fuel pricing.
- Integrated Resource Planning analyses.
- Economic or electricity demand growth analyses.
- Pricing impacts of demand responsiveness.

5.2.2.2 Public Documentation

USEPA uses IPM® to analyze the impact of air emissions policies on the U.S. electric power sector. As part of this analysis, USEPA publishes its assumptions and other information regarding its use of IPM® on its website (U.S. Environmental Protection Agency 2012). Although this documentation provides insight into USEPA's assumptions, the data and assumptions used by OEA in this analysis are not necessarily the same as used by USEPA.

5.3 Key Assumptions

In this use of IPM®, OEA made key assumptions regarding fuel; air, waste, and water regulations; renewable energy regulations; reserve margin targets; mothballing and retirement of existing power plants; and transmission. The following subsections address these assumptions.

5.3.1 Fuel

Fuel-related assumptions include those concerning coal surface mine productivity, coal underground mine productivity, and natural gas production and demand.

5.3.1.1 Coal Surface Mine Productivity

This section presents OEA's fuel-related assumptions concerning coal surface mine productivity. At a national level, between 1983 and 2000, coal mining productivity steadily increased. However, since 2000, coal mining productivity has been declining due to the imposition of new regulatory requirements, as well as increasingly difficult geology. Coal mine productivity has a direct impact on the cost of production and, thus, the price of coal. As mining productivity increases, the cost of production decreases, and as mining productivity decreases, the cost of production increases. The assumed productivity growth rates reflect these historical trends and take into account expected future regulations, geologic conditions, and increased use of longwall mining techniques in some regions. Table 5-2 provides surface mine coal productivity growth rates. The productivity growth rates reflect current productivity trends in the near term that are based on historical data from the Mine Safety and Health Administration. The long-term productivity growth rates are based on expected regulatory burdens, changes in geologic conditions, and the greater use of more efficient mining techniques. The mid-term productivity growth rates are a linear transition from the near term, historical based values, and the long-term forecasted values.

- OEA assumed that coal producers in the Powder River Basin would experience higher stripping ratios over time that will gradually reduce the productivity of the mines, which would result in a gradual cost increase.

- OEA also assumed that coal producers in the Illinois Basin and Rocky Mountains would manage to reverse the negative productivity trend of recent years, but would make only modest further gains in the future.
- In the Illinois Basin, OEA assumed that productivity gains reflect that incremental production would increasingly come from higher-sulfur coals, which have not been depleted as much as low-sulfur reserves.
- OEA assumed that Northern and Central Appalachian Basin productivity would decline in the long term resulting from the depletion of quality reserves and greater regulatory burdens.
- Finally, OEA assumed that Southern Appalachia Basin would see a slight increase in productivity.

Table 5-2. Coal Productivity Growth Rate (percent) Assumptions—Surface Mines

Basin Name	2013	2014	2015	2016	2017+
Northern Appalachia	-1.4	-1.1	-0.8	-0.5	-0.5
Central Appalachia	-2.6	-1.9	-1.2	-0.5	-0.5
Southern Appalachia	-1.6	-0.9	-0.2	0.25	0.25
Illinois	-1.2	-0.8	-0.4	0	0.13
Powder River	-1.3	-0.9	-0.6	-0.2	-0.1
Rocky Mountains	-2.9	-1.9	-0.8	0.25	0.25

5.3.1.2 Coal Underground Mine Productivity

This section presents OEA’s fuel-related assumptions concerning coal underground mine productivity.

- OEA assumed that coal producers in the Rocky Mountains and Northern and Central Appalachian Basins would continue the negative productivity trend of recent years, but at a lower rate of decline.
- OEA also assumed that underground Illinois Basin productivity would remain fairly flat because OEA expects that decreases in productivity due to increased safety requirements would be offset by increases in productivity that would increasingly come from higher-sulfur coals being mined using longwall techniques, which are more efficient. Higher-sulfur coals are not as depleted as lower-sulfur reserves and, thus, the geologic conditions are not as challenging.

Table 5-3 provides the underground mine coal productivity growth rates. As stated previously, between 1983 and 2000, coal mining productivity steadily increased at a national level. Since 2000, however, coal mining productivity has declined because of new regulatory requirements and increasingly difficult geology. The assumed productivity growth rates reflect these trends and take into account expected future regulations and geologic conditions.

Table 5-3. Coal Productivity Growth Rate (percent) Assumptions—Underground Mines

Basin Name	2013	2014	2015	2016	2017+
Northern Appalachia	-3.5	-2.6	-1.8	-1.0	-1.0
Central Appalachia	-4.0	-3.0	-2.0	-1.0	-1.0
Southern Appalachia	2.3	1.5	0.6	-0.2	-0.2
Illinois	0.94	0.66	0.38	0.1	0.1
Powder River	2.0	1.5	1.0	0.5	0.5
Rocky Mountains	-1.9	-1.3	-0.8	-0.2	-0.2

5.3.1.3 Natural Gas

The following are OEA's fuel-related assumptions, which take into account natural gas production and demand. Onshore conventional and offshore natural gas production continues to decline, while so-called unconventional production (i.e., fracking) has grown, and is expected to continue growing. These assumptions are based on OEA's thorough analysis of the natural gas market and represent the most probable outlook at the time of the forecast.

- Unconventional natural gas supplies include tight gas, coalbed methane, and shale gas.
- Total unconventional natural gas production is expected to increase to 26 trillion cubic feet by 2020 and 35 trillion cubic feet by 2035.
- Total natural gas demand is projected to increase at a rate of 1.5% per year.
- Power sector natural gas use would continue to grow in the longer term after uneven growth in the near term.
- Liquefied natural gas (LNG) exports are expected to total 6 billion cubic feet per day, 2 billion cubic feet per day from Canada and 4 billion cubic feet per day from the Gulf Coast.
- New gas-to-liquid plants are expected to add nearly 1 trillion cubic feet (2.6 billion cubic feet per day) of demand.
- Not much growth is expected in the residential and commercial sectors, but oil-to-gas conversions are likely to spur some regional growth.

5.3.2 Air, Waste, and Water Regulations

OEA's assumptions reflect current air, waste, and water regulatory requirements. These assumptions are based on a thorough analysis of current and proposed environmental regulations and represent the most probable outlook at the time of the forecast.

- As a result of USEPA's overturned Cross-State Air Pollution Rule on August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit temporarily reinstated the Clean Air Interstate Rule (40 Code of Federal Regulations [C.F.R.] Parts 51, 52, 72, 78, and 97). The assumed regulatory structure in the modeling includes state-level emissions budgets

with intrastate trading only for SO₂ and NO_x. On April 29, 2014, the Supreme Court reversed the D.C. Circuit's decision to overturn the Cross-State Air Pollution Rule. On June 26, 2014, the U.S. government filed a motion with the D.C. Circuit to lift the stay on the Cross-State Air Pollution Rule and allow the program to go forward with the first phase beginning January 1, 2015.

- The OEA assumed a future set of SO₂ and NO_x regulations more stringent than both the Clean Air Interstate Rule and the Cross-State Air Pollution Rule starting in 2018. The purpose of both rules is to help states achieve attainment with the 1997 National Ambient Air Quality Standards (NAAQS) for particulate matter up to 2.5 micrometers in size (PM_{2.5}) and 8-hour ozone. The Cross-State Air Pollution Rule also addresses the 2006 standards for PM_{2.5}. EPA is required to review the standards every 5 years. The analysis included more stringent requirements for SO₂ and annual NO_x beginning in 2018 to capture revisions to the PM_{2.5} NAAQS made by USEPA in 2012.
- Consistent with USEPA's Mercury and Air Toxics Standards, OEA's analysis assumes that all coal-fired generating units must be controlled for air toxics, or be within 1 year of being controlled, by 2016, or the units must be retired (40 C.F.R. Parts 60 and 63).
- In its Water Intake Structure proposal, USEPA mandated feasibility studies for generating units, but left the development of final remedies to the states (40 C.F.R. Parts 122 and 125). OEA's analysis, therefore, assumes that the states that have been proactive on water and environmental regulation in the past will require cooling towers under the rule.
- USEPA is developing coal combustion residuals requirements with which generating units must comply (U.S. Environmental Protection Agency 2014).
- State Clean Air Mercury Rule programs that are already in process will move forward as planned. OEA assumed that these programs will be at least as stringent as the Mercury and Air Toxics Standards requirements.
- OEA included the CO₂ cap in the Regional Greenhouse Gas Initiative for this analysis. The Regional Greenhouse Gas Initiative is a market-based regulatory program to reduce CO₂ emissions by setting a cap on emissions that decreases each year. Nine states in the northeast are part of the initiative (RGGI 2014).
- OEA also included the California Assembly Bill 32 cap-and-trade program in the analysis, which is expected to be more stringent than any likely federal CO₂ standards. The bill affects both in-state generation and power imported into California (Assembly Bill No. 32 Chapter 488).
- Other state SO₂ and NO_x regulations are included where final regulations exist.

5.3.3 Renewable Energy Regulations

OEA's assumptions take into account renewable energy requirements, as follows. These assumptions are based on a thorough analysis of the renewable energy market and represent the most probable outlook at the time of the forecast.

- The Investment Tax Credit is a 30% credit available to solar units, distributed wind systems, and geothermal heat pumps (distributed generation, aside from solar photovoltaic, is not modeled in IPM®). Under current policy, all units placed in service through the end of 2016 are eligible. In OEA's analysis, the credit is assumed to gradually phase out over the next 4 years.
- A Production Tax Credit of 2.2¢ per kilowatt hour is available for wind, closed-loop biomass, and geothermal units. The credit is 1.1¢ per kilowatt hour for landfill gas and open-loop biomass. Under the American Taxpayer Relief Act of 2013, the credit was extended for wind facilities that begin construction by the end of 2013, and for other qualified facilities that begin construction by the end of 2014. OEA included the Production Tax Credit in the analysis, using these assumptions.
- The Modified Accelerated Cost-Recovery System allows for full depreciation for wind, combined heat and power, geothermal, fuel cells, and solar units over a 5-year period. The biomass property class life is set at 7 years. In IPM®, the Modified Accelerated Cost-Recovery System is captured in the capital charge rate, effectively lowering the revenue requirements for renewable units.

5.3.4 Reserve Margin Targets

OEA's reliability-related assumptions reflect planning reserve margin requirements, which are targets for generating capacity that are used to ensure sufficient generating capacity is available at all times, such as when some plants are out of service for maintenance or equipment problems occur during peak demand periods.

- The reserve margin assumptions used in IPM® are based on the planning reserve margins determined by regional planning authorities subject to North American Electric Reliability Corporation standards. For example, in New York, the planning reserve margin is obtained from New York Independent System Operator (NYISO) documents.

5.3.5 Mothballing and Retirement

OEA's assumptions reflect the ability of electricity generating plants to mothball or retire. The capability to model plants entering a mothball state or retiring more realistically represents the actual energy market than a model that does not include this capability.

- To capture market exit behavior, IPM® included mothballing and retirement capabilities. Generating units with high fixed operations and maintenance costs become candidates for mothballing and retirement as more efficient generation capacity is constructed.

- The mothballing option is provided for all oil/natural gas steam facilities and is exercised if short-term annual fixed costs exceed annual revenues in a market with excess supply. The decision to mothball takes into consideration fixed costs, reserve requirements, and the costs of mothballing a unit and returning it to service at a later date.
- Retirement options are available to all existing coal, nuclear, and oil/natural gas steam units in IPM[®]. The modeling assumed that the retirement option would be exercised if projected discounted cash flows do not exceed projected costs (fixed, variable, and capital). Again, this decision takes long-term reserve requirements and revenues into consideration.
- OEA's analysis assessed higher fixed operations and maintenance costs to uncontrolled coal units after 60 years in service to account for life-extension costs, potentially increasing the amount of coal retirements as the model chooses to retire units rather than pay the life-extension costs.

5.3.6 Transmission

OEA's assumptions took into account the capabilities of transmission lines. These assumptions are based on a thorough analysis of the natural transmission structure and constraints, and represent the most probable outlook at the time of the forecast.

- Joint capacity constraints were included to reflect limitations across groups of transmission links.
- OEA used total transmission capability assumptions from public sources such as the North American Electric Reliability Corporation and regional reliability councils, as well as interface limits published by the International Organization for Standardization, where available.
- In regions where data were unavailable, the analysis used estimates derived from industry contacts and proprietary modeling exercises.
- OEA assumed that power transported across power pools would incur a cost of \$3.09 per megawatt hour (2011 U.S. dollars) to reflect charges assessed by one power pool to another.
- IPM[®] did not include regional through-and-out rates for any transactions terminating in the combined PJM-MISO footprint. Regional through-and-out rates are transmission rates for transactions where electricity originated in one transmission control area was transmitted to a point outside that control area.
- Transmission losses vary with line loading and line length, but estimating the exact loss factors for each interconnecting transmission path for the entire country would be impracticable. OEA's analysis, therefore, assumed transmission losses between 2 and 3%, based on industry practices. Note that these losses were intended to capture only bulk power transmission losses; distribution losses were not included.

5.4 Methods

This section provides an overview of the methods used in the analysis.

5.4.1 Model Run Years

Table 5-4 presents a map of calendar years and run years. Run years aggregate calendar years to limit model complexity. In other words, a run year is a calendar year chosen to represent a single year or a group of years in which prevailing electricity and fuel market conditions and environmental policies are expected to be most similar. The number of IPM® run years must be limited to decrease model complexity. The analysis period of 2018 to 2037 reflects the 20-year period of reasonably foreseeable coal production and transport by the proposed rail line.

Table 5-4. Mapping of Calendar Years and Model Run Years

Calendar Year	Run Year
2013	2013
2014	2014
2015	2014
2016	2016
2017	2016
2018	2018
2019	2018
2020	2018
2021	2018
2022	2018
2023	2023
2024	2023
2025	2023
2026	2023
2027	2023
2028	2030
2029	2030
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2032	2030
2033	2030
2034	2037
2035	2037
2036	2037
2037	2037

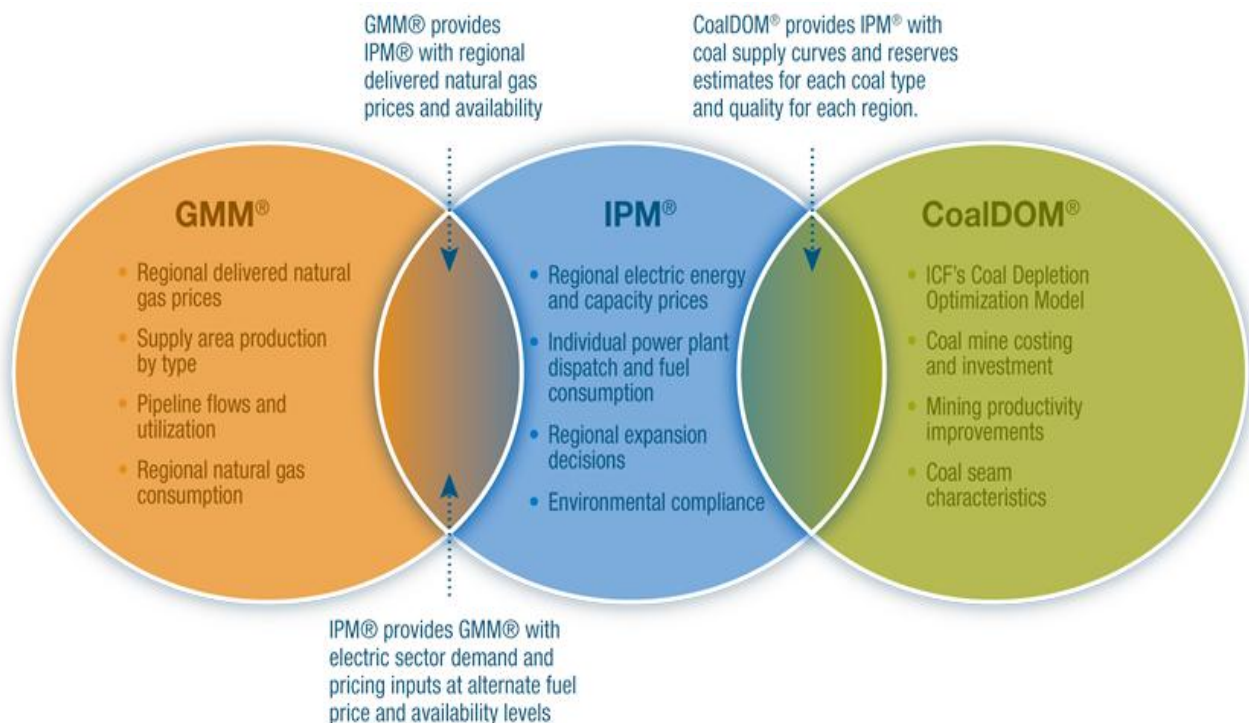
5.4.2 Coal

5.4.2.1 Modeling U.S. Coal Production

IPM[®] optimizes coal production, transportation, and consumption. For this purpose, the model uses coal supply curves developed using the Coal Depletion Optimization Model (CoalDOM[®]), which is used to build up supply curves for 65 different coal supply basins in the United States and internationally. Coal supply curves are developed for 13 coal types distinguished by rank and sulfur content. There are multiple coal supply curves for each supply basin corresponding to the major coal quality types in that region. The supply curves consist of a series of supply “steps” that consist of a production cost, annual production capacity, and a coal resource limit. These supply curves are then incorporated into IPM[®]. Each coal power plant in IPM[®] is assigned to one of 180 U.S. and Canadian coal demand regions represented in the model. The coal demand regions are distinguished by location, mode of delivery, and captive versus competitive transportation status.

This section characterizes CoalDOM[®]; Figure 5-2 shows CoalDOM[®]'s interaction with the ICF International Gas Market Model (GMM[®]) and IPM[®].

Figure 5-2. Integrated Fuel and Power Market Modeling Approach



Inputs into CoalDOM[®] include the individual mine characteristics of all existing U.S. mines, including remaining reserves, and undeveloped coal resource estimates for each region and coal type. The coal reserve data are based on the U.S. Energy Information Administration

(EIA)'s latest. Where available, OEA used reserve data from company financial reports and coal reserve estimates from the U.S. Geological Survey to supplement EIA estimates.² The coal resource estimates for potential new mines are provided by surface and underground categories for each region.

The model then assigns the existing mine data and coal resource estimates to one of 16 different prototypical mines distinguished by the stripping ratio, seam thickness, and mining method, for surface mines, and the depth to seam, seam thickness, and mining method, for underground mines. The 16 prototypical mines make up the core of the mine-costing model used to estimate the cost of extracting coal from each mine type. Once the mine-costing model calculations are completed, the results are sorted in ascending cost order to form supply curves for each supply region and coal type, for each year in the analysis period. In addition to the cost estimate, each coal supply curve step includes an estimate of the annual production capacity and the total coal reserves/resources assigned to that step. International supply curves are derived at a more aggregate level than the U.S. supply regions; however, they follow the same structure with respect to each step having an estimate of the production capacity and the total coal reserves/resources assigned to that step.

CoalDOM[®] includes a comprehensive database that tracks ownership, production, productivity, reserves, mining method, coal quality, seam thickness, and other characteristics for all U.S. mines.

CoalDOM[®]'s key mine variables are defined below. The variables of greatest importance are geography and quality.

- **Geography.** Refers to the state with coal reserves. In some cases where a state has multiple coalbeds with different characteristics (such as Kentucky, West Virginia, Pennsylvania, Wyoming, Montana, New Mexico and Colorado), CoalDOM[®] splits the coal reserves in those states into more than one supply region.
- **Quality.** Refers to the rank and sulfur content of coal. CoalDOM[®] includes three coal ranks (bituminous, lignite, and subbituminous), and six sulfur grades, although not all sulfur grades apply to each coal rank.
- **Type.** Refers to whether a coal reserve is accessible with surface or underground techniques.
- **Technology.** Refers to the technique of extraction used. Underground reserves are classified as either longwall or continuous mining. Surface reserves are classified as contour strip, dragline, truck and shovel, or mountaintop removal.
- **Technology subtype.** Refers to the depth of the reserves for underground mines or the stripping ratio for surface mines.

² Reserve data from financial reports from the following coal mining companies were used to supplement the EIA reserve data: Arch Coal, Alpha Natural Resources, Alliance, American Power Corporation, Cloud Peak, CONSOL, Energy Future Holdings, Foresight Energy, Grande Cache Coal, Hallador Energy, Natural Resource Partners, Oxford Resource Partners, Patriot Coal Corporation, Peabody Energy, Rhino Resource Partners, James River, Walter Energy, and Westmoreland Coal.

- **Production category.** Refers to seam thickness for underground mines (i.e., less than 42 inches, 42 to 72 inches, 72 to 96 inches, more than 96 inches) or the annual production category for surface mines (i.e., less than 2 million tons, 2 to 5 million tons, and more than 5 million tons per year).
- **Vintage.** Distinguishes between existing and potential mines. Existing mines are those already in production according to Mine Safety and Health Administration data and are assumed to have lower extraction costs at the margin due to sunken capital costs, which are taken into account in CoalDOM[®]'s algorithms. Potential mines are those with viable reserves, but where no development work or infrastructure exists.

Coal types modeled in each supply region are assigned a two-letter code to distinguish between coal rank and sulfur content. The first character indicates the coal rank, specifically B, S, or L for bituminous, subbituminous, and lignite. The second character indicates the sulfur content of the coal and is designated by letters A, B, D, E, F, and G. Table 5-5 shows the definitions of the sulfur grades by coal rank.

Table 5-5. Coal Types Modeled

Fuel Code	Description	SO ₂ Content (lbs/MMBtu)	CO ₂ Content (lbs/MMBtu)	Mercury Content Range (lbs/TBtu) ^a
BA	Bituminous–low sulfur	0.90	205.30	3.6 to 6.3
BB	Bituminous–compliance spec	1.20	205.30	4.5 to 27
BD	Bituminous–NYMEX spec	1.67	205.30	6 to 18
BE	Bituminous–medium sulfur	2.70	205.30	6 to 18
BF	Bituminous–high sulfur	4.20	205.30	5.4 to 32
BG	Bituminous–very high sulfur	6.00	205.30	6 to 32
CK	Bituminous–coking coal	1.20	205.30	5.61
SA	Subbituminous–ultra low sulfur	0.50	212.70	4.0
SB	Subbituminous–low sulfur	0.65	212.70	6.0
SD	Subbituminous–standard Powder River Basin spec	0.80	212.70	6.0
SE	Subbituminous–medium sulfur	1.55	212.70	6.0
LD	Lignite–medium sulfur	2.00	215.40	7.0
LF	Lignite–high sulfur	3.55	215.40	8.0
WC	Waste coal	5.64	205.70	63.9
PC	Petroleum coke	7.20	213.00	22.6

Notes:

^a Mercury content changes by coal supply region

lbs = pounds; MMBtu = million British thermal units; TBtu = trillion British thermal units

IPM[®] includes integrated U.S. and international coal market modeling: CoalDOM[®] and IPM[®] provide integration with international coal markets. Figures 5-3 and 5-4 show the domestic and international coal supply regions. The modeling platform captures terminal capacity limits, international shipping costs, steam and metallurgical coal supply, and demand from both electricity and nonelectricity sectors.

Figure 5-3. Domestic Coal Supply Regions

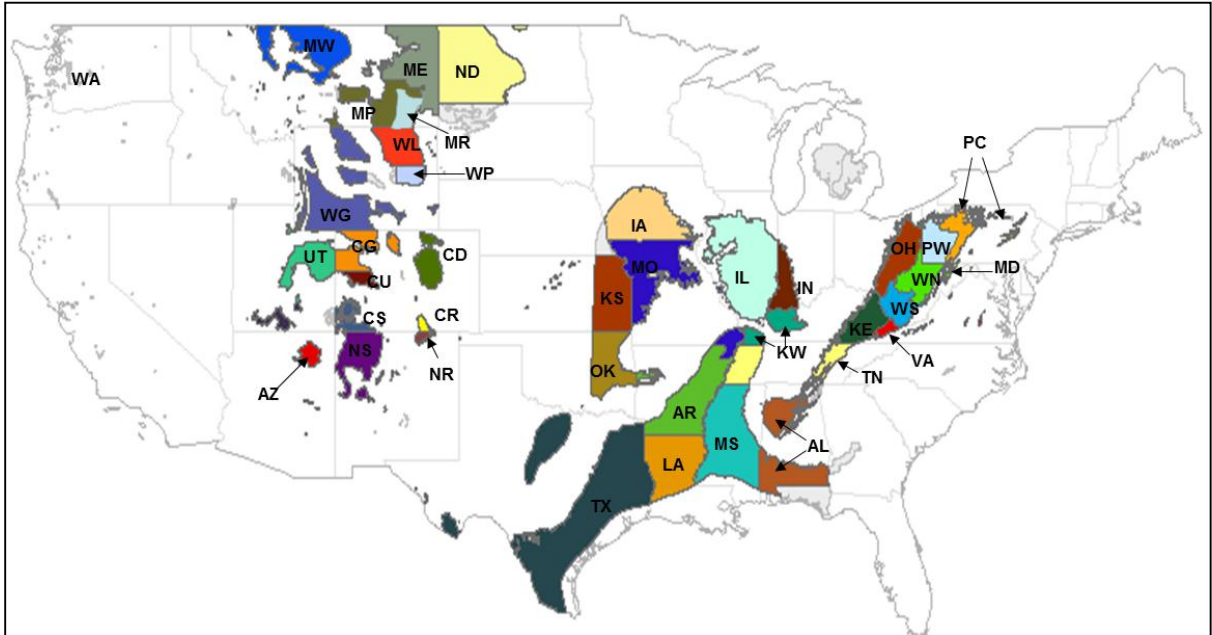
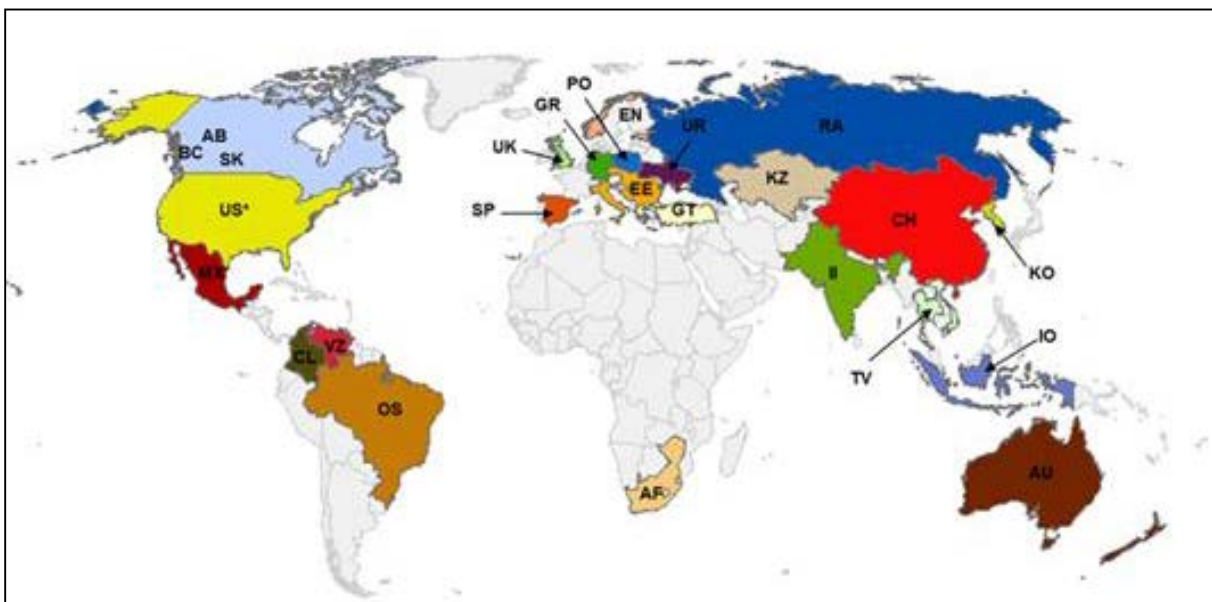


Figure 5-4. International Coal Supply Regions



5.4.2.2 Overall Powder River Basin Supply Curve

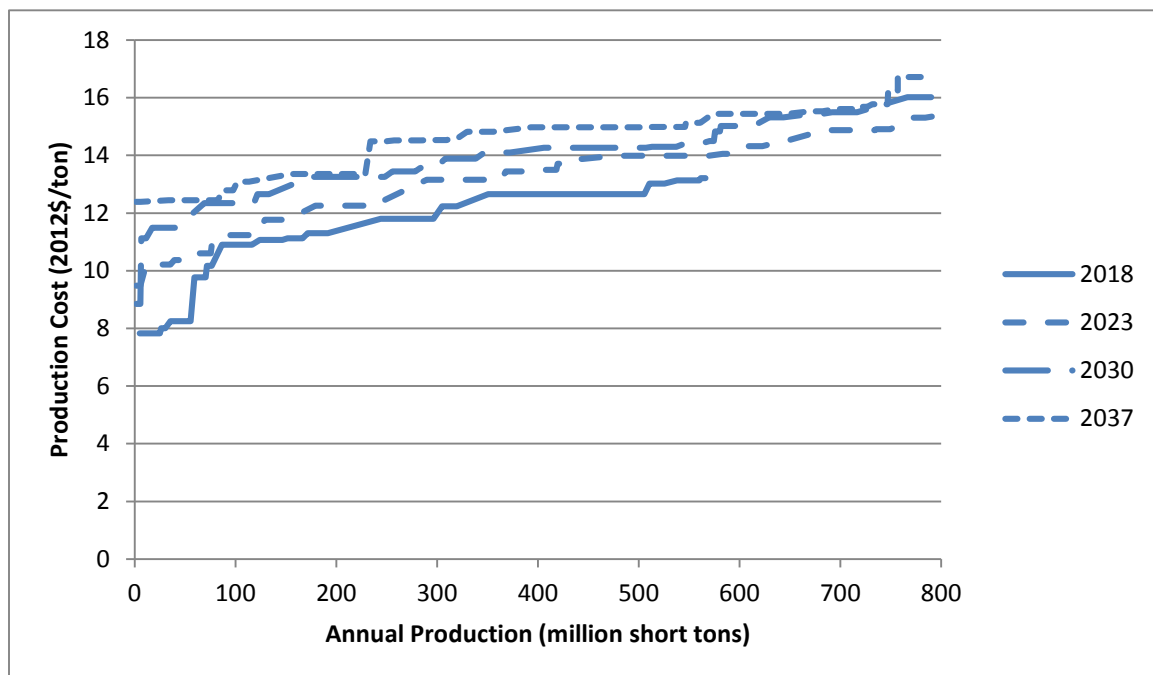
To model the Powder River Basin region, IPM[®] includes four coal supply regions.

- Two regions in Wyoming representing Wyoming 8400 and Wyoming 8800 coal (Powder River Basin coal).
- One region representing the existing mines in Montana (Montana coal).
- One region representing the new mine activity in the Tongue River area (Tongue River coal).

The remaining U.S. coal-producing regions are represented by an additional 36 coal-supply regions, for a total of 40 coal supply regions.

The aggregate supply curve for all Powder River Basin mines is shown in Figure 5-5.

Figure 5-5. Montana and Wyoming Powder River Basin Coal Production Cost Curve



Two primary factors influence the shape of the cost curves by year. First, depletion effects at existing mines are considered, which result in production costs in later years being higher than in the initial years (reflecting higher stripping ratios over time). This shifts the cost curves upward for the later years. Second, technological advancement and increases in market prices allow for increased economic viability of new coal mines. This extends the cost curves because new mines could be developed in later years. For example, the 2018 production cost curve extends only out to about 570 million tons, which is the expected maximum production from existing and planned mines, as new unplanned mine capacity is not expected to come online by 2018. The production cost curves for later years extend out

to about 800 million tons per year, reflecting the possibility of new mines coming online by that time.

5.4.2.3 Coal Demand

Using IPM[®], coal demand is determined in the United States and Canada by the dispatch of existing coal-fired power plants, and elsewhere by projections of coal demand by country. Within a model run, IPM[®] calculates thermal coal consumption for each coal-fired electricity generation plant in the United States and Canada. Thermal coal consumption and coal prices are determined by the supply and demand economics of meeting the electricity demand. The plant specific coal consumption and coal supply region price projections result in an integrated and consistent analysis in IPM[®] of the electricity demand; natural gas supply and prices; air emission regulations for NO_x, SO₂, hydrogen chloride, and mercury; CO₂ policy alternatives, and renewable portfolio standards and explicit modeling of renewable generation options.

If the future electricity demand cannot be met by existing power plants, IPM[®] will determine the type and amount of new generating capacity required to meet the electricity demand on a least cost basis. The different types of capacity that can be added consist of combustion turbines, combined cycles, nuclear units, wind plants, and coal-fired units. Thus, if IPM[®] determines that new coal plants in the United States and Canada are necessary, it will increase coal demand. IPM[®] can also determine that it is most economical to retire existing coal plants, which would decrease coal demand. Using this structure, IPM[®] is able to model explicitly the shifts in coal demand related to environmental mandates, natural gas prices, and coal production and transportation costs. For example, if natural gas prices are low, more electricity will be generated by natural gas-fired combined cycles and coal consumption will be lower than in a case with higher natural gas prices. Outside of the United States and Canada, coal demand is estimated using historical coal consumption data, expected coal plant construction, and economic growth on a country-by-country basis. Both thermal and metallurgical coal demand is forecast using this method.

Table 5-6 shows the coal demand forecast for China, the rest of the Pacific Basin, and the rest of the world (excluding the United States), as well as metallurgical coal demand. As the forecast shows, China will continue to be the largest thermal coal consumer worldwide through 2037.

Table 5-6. Global Thermal Coal Demand (million tons)

Year	China ^a	Rest of Pacific Basin ^b	Rest of World (non-United States) ^c	United States	Metallurgical Coal	Total
2018	4,447	2,079	1,711	918	1,103	10,258
2023	4,727	2,431	1,720	969	1,127	10,975
2030	4,947	2,927	1,707	970	1,156	11,708
2037	5,169	3,571	1,727	1,030	1,176	12,675

Notes:

^a China uses nearly half of its thermal coal to heat homes, which is included in the estimate of coal consumption.^b Rest of Pacific Basin includes Australia, Bangladesh, Hong Kong, India, Indonesia, Japan, Korea, Laos, Myanmar, Singapore, Taiwan, Thailand, and Vietnam. India is included despite its proximity to the Indian Ocean.^c Rest of the world (non-United States) includes all countries outside of the Pacific Basin and excludes the United States.

In terms of nonelectricity sector demand for thermal coal and demand for metallurgical coal, IPM[®] includes domestic and international forecasts that serve as the demand for this coal. IPM[®] has an international coal supply and demand representation that enables it to project coal exports out of and imports into the United States. Table 5-7 summarizes overall U.S. electricity demand forecasts.

Table 5-7. U.S. Peak Demand and Energy Forecasts

Year	Energy (TWh)	Peak (GW)
2011	3,924.6	723
2012	3,986.2	736
2013	4,055.0	750
2014	4,121.1	763
2016	4,246.6	788
2018	4,366.3	810
2023	4,644.7	861
2030	5,003.0	925
2037	5,340.4	985
2044	5,672.5	1,043

Notes:

TWh = terawatt hours; GW = gigawatts

5.4.2.4 Coal Transportation

The CoalDOM[®] model also connects the 40 U.S. coal supply regions and the 25 international supply regions with 178 coal demand regions in the United States and Canada, and 26 international coal demand regions (CoalDOM is described in Sections 5.4.2.1 through 5.4.2.3). The coal demand regions are defined based on geography, primary shipment method (e.g., rail, barge, truck), and whether electricity generating plants in the region have captive or competitive delivery situations. Coal plants with captive delivery have only one

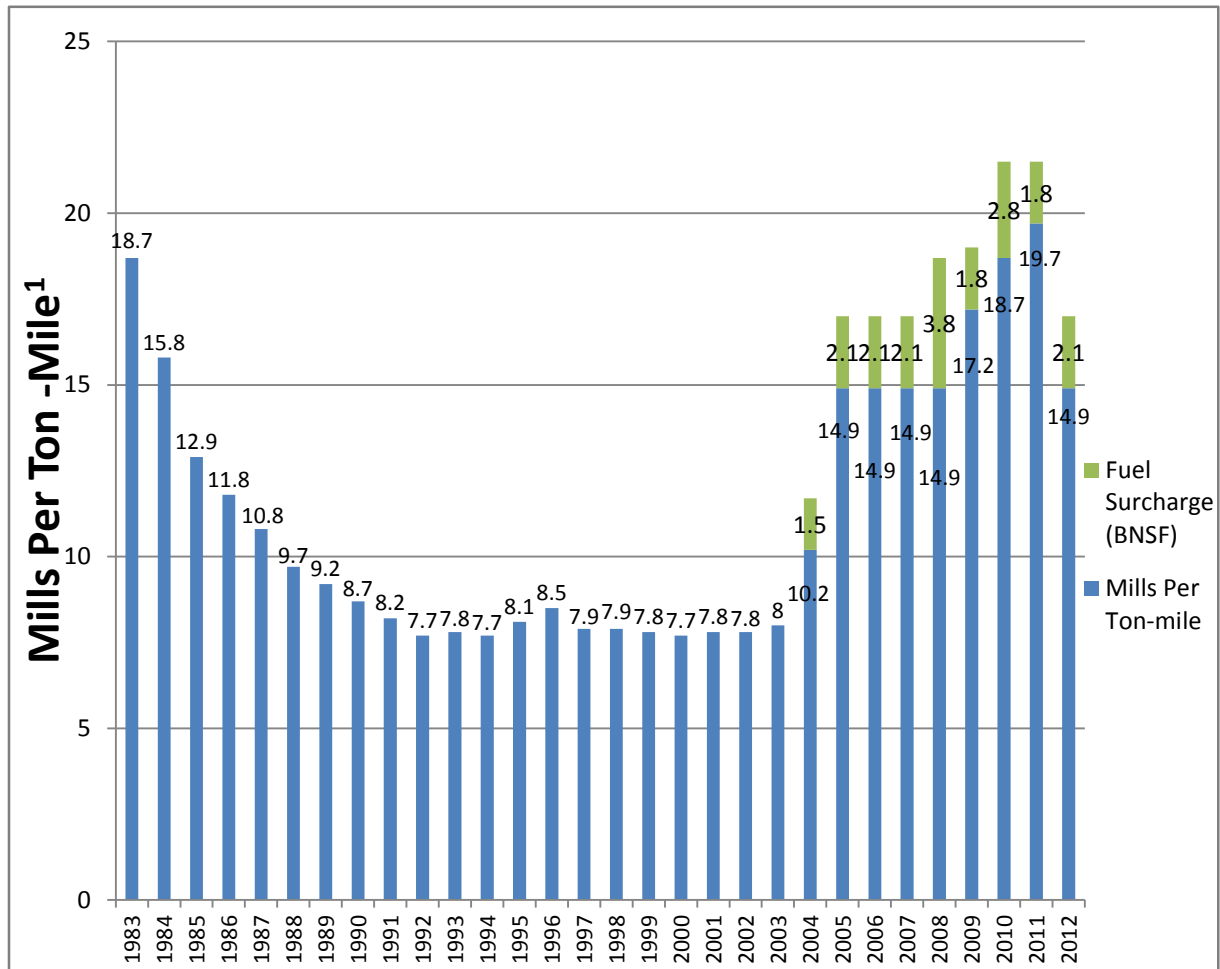
rail carrier delivering to their area or only one delivery mode available. The links between supply and demand regions are based on existing rail, barge, and truck shipment data and contain the mileage between each region by mode. Each coal demand region typically has 10 to 15 supply regions connected to it, using one or more transportation modes. Rail costs increase over time due to an increasing fuel surcharge. For international shipments, shipping rates are estimated based on published shipping cost data and are adjusted going forward based on projections of the global shipping index, the Baltic Dry Index.

During each run, IPM® determines the least cost means to meet power sector demand for coal as part of an integrated optimal solution for power, fuel, and emissions markets. Thus, IPM® is able to determine the optimal sourcing of coal for each power plant based on the predicted coal prices and transportation costs. Table 5-8 summarizes the transportation rates. The \$0.017/ton per mile rail rate (including the fuel surcharge) for Powder River Basin movement is similar to recent historical transportation rates for new Powder River Basin rail contracts (Figure 5-6).

Table 5-8. U.S. Coal Transportation Rate (2012)

Transportation Mode	Captive Plants (dollars/ton-mile)	Noncaptive Plants (dollars/ton-mile)	2012 Fuel Surcharge (dollars/ton-mile)
Rail			
Western	0.017	0.014	0.003
East of Mississippi, West of Appalachian	0.028	0.027	0.003
East of Appalachian	0.089	0.073	0.003
Barge			
All barge	0.020	0.019	0
Truck			
All truck	0.089	0.089	0
Notes: Sources: Fieldston Company, Pace Global Energy Services, and Hellerwox 2012			

Figure 5-6. Rail Rates for Shipments of Powder River Basin Coal to Competitively Served Destinations on BNSF or Union Pacific Railroads



Mills Per Ton-Mile = thousandths of a dollar per ton mile

5.4.3 Environmental Compliance

5.4.3.1 Plant-by-Plant Compliance Overview

IPM[®] incorporates constraints on emissions of NO_x, SO₂, hydrogen chloride, mercury, CO₂, and potentially other pollutants into its optimization process for all U.S. generating plants. Constraints are specified on the basis of target emissions rates, cap-and-trade policies, dollars per ton emitted tariffs, or command-and-control policies, and applied to individual generating units or groups of units. Power-generating units subject to environmental regulations have the following compliance options, with any combination or individual use of the first four options as a viable compliance mechanism.

- **Reduce running regime.** To comply with non-command-and-control policies, such as target emissions rates or an emissions cap, a unit can reduce the number of hours in a year it operates and shift when it operates to hours that are more lucrative, which would

be during peak demand periods of a day or year. For example, a plant might run only during the peak hours of 6:00 a.m. and 10:00 p.m., or only during the peak summer season.

- **Fuel switch.** Coal-fired units can choose from a variety of coals of different sulfur and mercury contents to minimize emissions and allowance cost impacts. The demand for these lower content coals results in premiums for those coals, over coals with higher pollutant contents. This premium may shrink if, for example, control becomes the dominant compliance option and higher pollutant content coals can be burned by controlled units. Oil units are generally offered fuels with different sulfur contents as well. The system may also fuel switch, from new coal builds to new natural gas builds, for example, to address CO₂ emissions requirements.
- **Retrofit.** For the four pollutants NO_x, SO₂, hydrogen chloride, and mercury, a variety of retrofit technologies is available to reduce emissions. In the case of CO₂, IPM[®] includes potential carbon capture-and-sequestration technology retrofits that can be applied to both new and existing units.
- **Purchase allowances.** By calculating an allowance price, IPM[®] is implicitly assuming that some units are sellers of allowances and others are buyers.
- **Retire.** A unit can be forced to retire or be given the economic option to retire if it cannot cover its operating costs going forward.

5.4.3.2 Carbon Dioxide Emissions

IPM[®] has the capability to model carbon policies as a cap-and-trade program or as a strict limit on CO₂ emissions from the power sector or the economy as a whole. In scenario 23, the scenario that includes a CO₂ policy (Chapter 7, *Scenarios*), OEA assumes a federal charge on CO₂ that begins in 2023, and that reflects a national cap-and-trade or rate-based trading program. The modeled CO₂ program reflects the potential for regulation or legislation that covers CO₂ emissions only from the power sector. As of mid-2014, a policy that goes beyond the power sector seems unlikely, based on public and Congressional sentiment. The New Source Performance Standards for CO₂ for new and modified sources are reflected in the model by requirements that any new coal units, other than those named by USEPA as exceptions, would have to be constructed with carbon capture and sequestration.

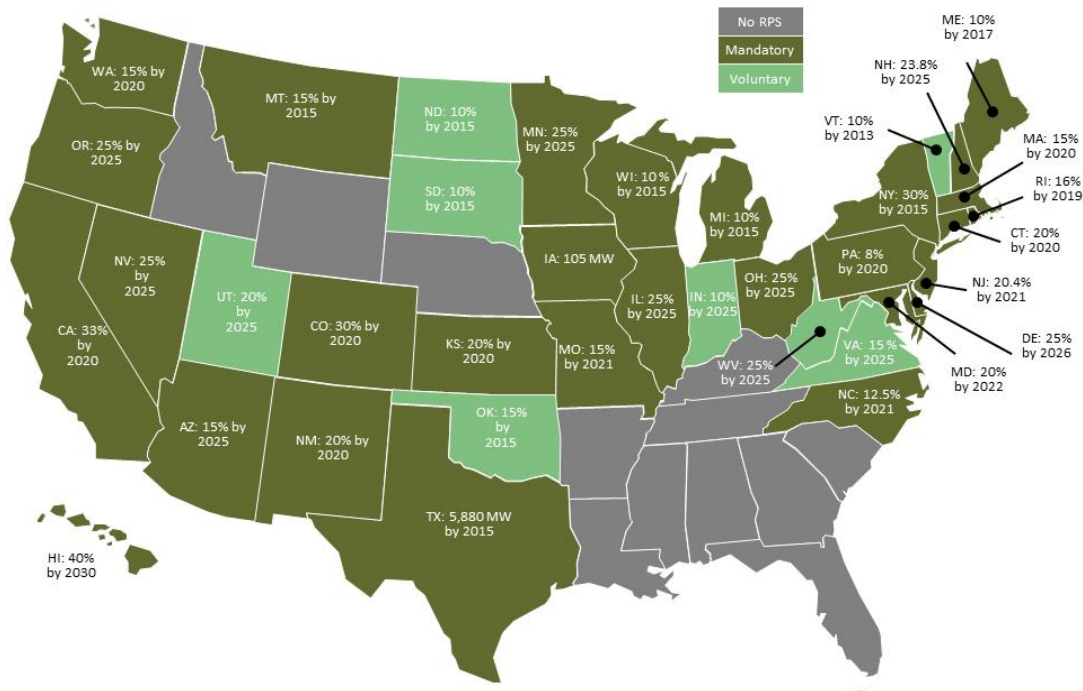
5.4.3.3 Renewable Portfolio Standards

IPM[®] treats renewable portfolio standards as follows.

- Twenty-nine states and the District of Columbia have passed mandatory renewable energy requirements; eight more have enacted voluntary standards or goals (Figure 5-7).
- The design of each renewable portfolio standard varies by target and timing, the types of renewable generation allowed, the geographic scope within which a generator might be

eligible to meet the standard, and the types of enforcement mechanisms and escape clauses included.

Figure 5-7. Renewable Portfolio Standards



Renewable generation capacity tends to have a higher leveled cost than fossil-fuel generation. To encourage the development of renewable capacity, many states allow generators to commoditize the green attributes of renewable power in renewable energy credits.³ The sale of such credits can provide supplemental revenue.

5.4.3.4 Other State and Regional Requirements

The modeling also addresses the following state and regional programs.

- IPM[®] included the CO₂ cap currently specified in the Regional Greenhouse Gas Initiative.
- IPM[®] includes California Assembly Bill 32 cap-and-trade program, which affects both in-state generation, as well as power imported into California.
- IPM[®] includes other state SO₂ and NO_x regulations where final regulations exist.

³ Alternative terms used for such instruments include *green tags* and *renewable energy certificates*.

5.4.4 Natural Gas

5.4.4.1 Reduced-Form Natural Gas Market Model Supply Curves

IPM[®] contains supply curves and other natural gas assumptions from the Gas Market Model (GMM[®]), ICF International's proprietary natural gas model. Multiple GMM[®] runs are used to define annual natural gas supply curves for the North American electricity market, implicitly taking into account changes in demand by other sectors at different price steps. When fundamental natural gas market assumptions change, the supply curves are regenerated to capture the impacts of those changes on available supply and cost. The incorporation of the natural gas price dynamics associated with changes in electricity demand, power plant builds, coal prices, and environmental policies have proven critical to providing robust forecasts. When only a static natural gas price forecast is used, without the inclusion of natural gas price dynamics, all interactions between gas prices and market drivers are lost. For example, if a new carbon policy is assumed, coal demand would tend to decrease and natural gas demand would increase due to the relative carbon content of these fuels. As the natural gas demand increases, the natural gas prices would tend to increase, and may increase substantially, depending on the available supply. Using static natural gas pricing would lose this dynamic between demand and natural gas prices, resulting in a forecast that is not representative of true market forces.

5.4.4.2 Natural Gas Market Model Overview

GMM[®] is an internationally recognized natural gas market analysis system that calculates monthly natural gas demand, production, storage activity, LNG imports and exports, pipeline flows, and prices at 118 market centers throughout the United States and Canada. GMM[®] has been used to study the following issues, among others.

- Assessing the impact of low and high natural gas supply growth.
- Analyzing the impact of pipeline expansions.
- Measuring the impact of natural gas-fired power generation growth.
- Assessing the impact of different regulatory environments.
- In addition to its use for strategic planning studies, GMM[®] has been used by institutional clients and advisory councils.
- The National Petroleum Council's Balancing Natural Gas Policy study in 2003.
- Interstate Natural Gas Association of America natural gas infrastructure studies in 1998, 2004, and 2009.

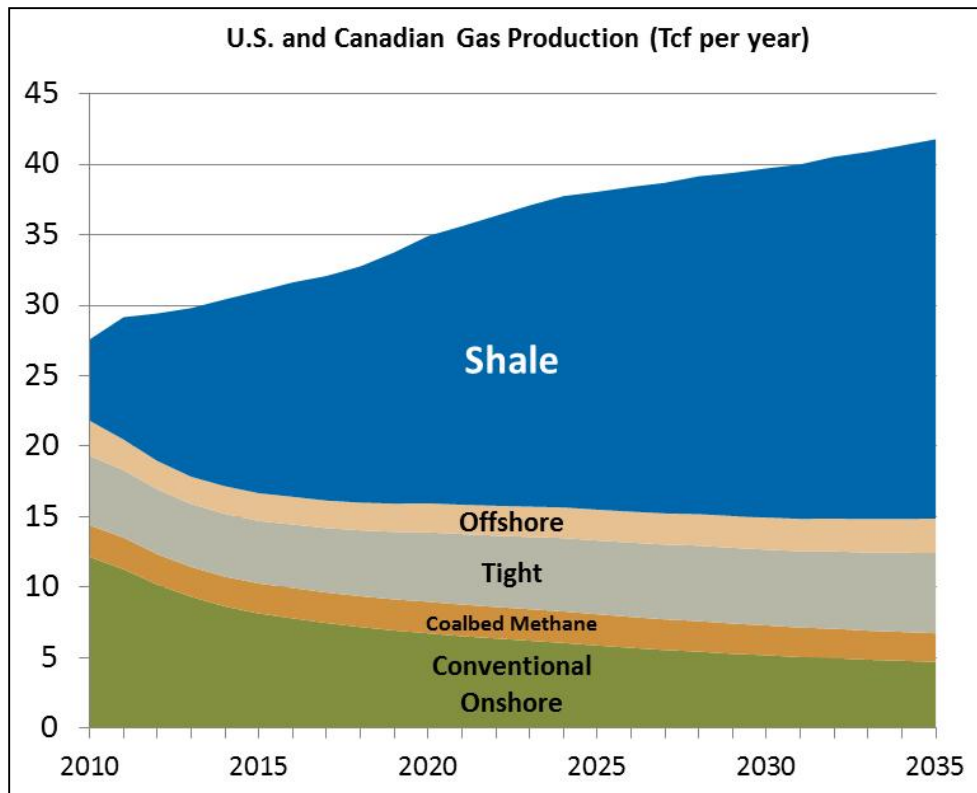
5.4.4.3 Natural Gas Supply Method

Total U.S. and Canadian natural gas supplies include production, LNG imports, and storage withdrawals (in the withdrawal season only). Natural gas production is presented for 80 distinct regions throughout the United States and Canada, and is represented by both short- and long-run supply curves. Table 5-9 provides a list of the 80 supply regions used in the natural gas modeling. In the short run, natural gas production is bound by the amount of available productive capacity. In the long run, productive capacity changes as a function of the available natural gas resource, the cost of development, and the natural gas price at the time. Figure 5-8 portrays U.S. and Canadian natural gas production in trillion cubic feet per year.

Table 5-9. List of Natural Gas Supply Regions

• Niagara	• San Juan Basin	• Henry Hub	• South Alaska
• Southwest PA	• EPNG/TW	• North Louisiana Hub	• Central Alaska
• East Ohio	• North Wyoming	• Central and West Louisiana Shelf	• North Alaska
• Maumee/Defiance	• South Nevada	• Southwest Texas	• Arctic
• Lebanon	• SOCAL Area	• Dallas/Ft Worth	• Norman Wells
• Indiana	• Enhanced Oil Recovery Region	• East Texas (Katy)	• Southwest Virginia
• South Illinois	• PGE Area	• South Texas	• North Florida
• North Illinois	• Pacific Offshore	• Offshore Texas	• Southwest Michigan
• Southeast Michigan	• Montana/North Dakota	• Northwest Texas	• Northern Michigan
• East Kentucky/Tennessee	• Pacific Northwest	• Garden Banks	• Carthage
• Wisconsin	• North Nevada	• Green Canyon	• Southwest Oklahoma
• Northern Missouri	• Idaho	• Eastern Gulf	• Northeast Oklahoma
• Minnesota	• Eastern Canada Offshore	• North British Columbia	• Southeastern Oklahoma
• Crystal Falls	• Atlantic Offshore	• Caroline	• Northern Arkansas
• Ventura	• North Alabama	• Saskatchewan	• Southeast Missouri
• Nebraska	• Alabama Offshore	• Manitoba	• Uinta/Piceance
• Kansas	• North Mississippi	• Dawn	• South Mississippi/Alabama
• East Colorado	• East Louisiana Shelf	• West Virginia	• West Kentucky/Tennessee
• Opal	• Eastern Louisiana Hub	• Wind River Basin	• Northeast Pennsylvania
• Cheyenne	• Viosca Knoll/Desoto/Miss Canyon	• MacKenzie Delta	• Leidy

Figure 5-8. Natural Gas Market Model: Gas Supply



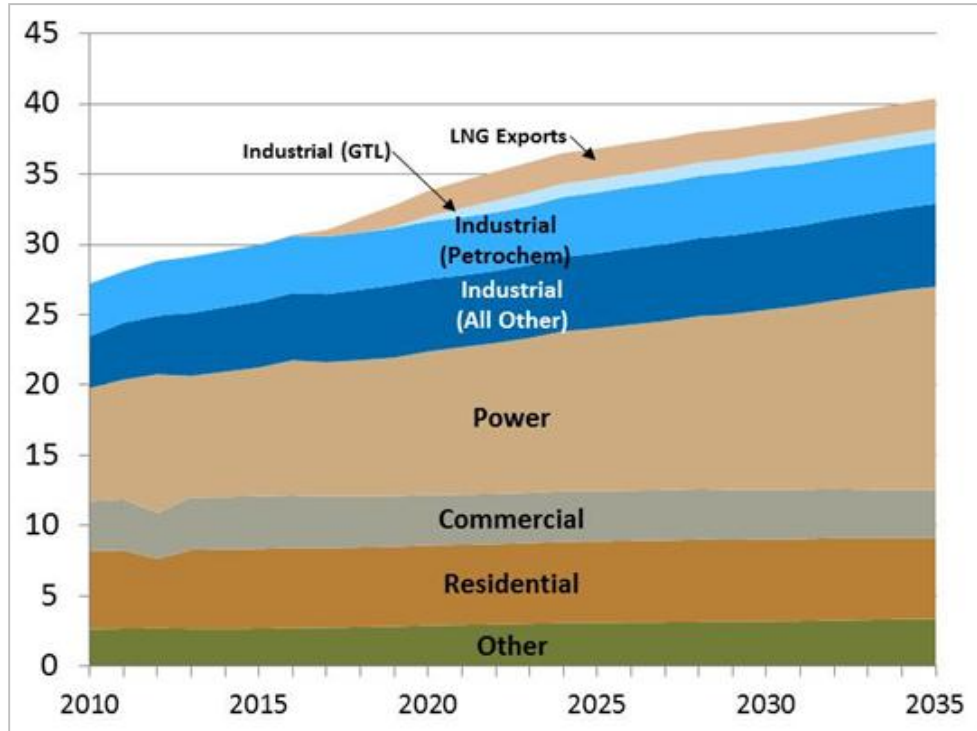
Model results show the following.

- Onshore conventional and offshore natural gas production will continue to decline, while unconventional production will grow.
- Unconventional natural gas supplies include tight gas, coalbed methane, and shale gas. Of the three, shale gas is by far the fastest growing type of unconventional natural gas production. Tight gas is gas produced from low-porosity reservoir rock, typically sandstone and limestone, which requires hydraulic fracturing to produce the gas economically. Shale gas is a subset of tight gas that is typically reported separately.
- Total unconventional natural gas production to increase to 26 trillion cubic feet by 2020 and 35 trillion cubic feet by 2035. The vast majority of the growth in unconventional natural gas production is expected to come from shale gas.

Other sources of supply of natural gas are imports of LNG and withdrawal from storage. Within each model run, North American LNG imports are determined by LNG-specific supply curves. To develop the LNG supply curves, OEA combined data on existing and planned liquefaction facilities with a projection for world natural gas demand to arrive at projected volumes of LNG available to North America at various price levels. OEA estimated the number and timing of new LNG import terminals and input these data into the model for each scenario. OEA then determined storage withdrawals within the model based on “storage supply curves” that reflect the level of withdrawals relative to natural gas prices.

The curves have been calibrated using historical price and withdrawal data. Figure 5-9 portrays U.S. and Canadian natural gas demand.

Figure 5-9. U.S. and Canadian Natural Gas Demand (trillion cubic feet per year)



5.4.4.4 Natural Gas Demand Assumptions

Key elements of the GMM[®] natural gas demand forecast include the following assumptions. These assumptions are based on a thorough analysis of the natural gas market and represent the most probable outlook at the time of the forecast.

- Total natural gas demand will increase at an estimated rate of 1.5% per year.
- Power sector natural gas use will continue to grow after uneven growth in the near term.
- New gas-to-liquid plants will add nearly 1 trillion cubic feet (2.6 billion cubic feet per day) of demand.
- LNG exports will total 6 billion cubic feet per day (2 billion cubic feet per day from Canada and 4 billion cubic feet per day from the Gulf Coast).
- Not much growth will occur in the residential and commercial sectors, but oil-to-gas conversions are likely to spur some regional growth.

5.4.4.5 Natural Gas Demand Method

The model calculates separate natural gas consumption for the residential, commercial, industrial, and electricity power sectors, as well as pipeline fuel and lease and plant natural

gas use. The end-use and power sectors have both short- and long-run demand curves. Short-run demand is largely determined by weather and the economy. Long-run natural gas demand growth can change as natural gas prices and macroeconomic assumptions change over time.

A variety of factors drive natural gas demand growth in the residential and commercial sectors, including weather, increases in residential housing stock and commercial building square footage, and efficiency and conservation trends. The model considers existing regulations that affect efficiency, such as the phase-in of new appliance efficiency standards.

Industrial natural gas demand growth is driven by growth in industrial output (as measured by the industrial production index) and changes in natural gas intensity (natural gas use per dollars of output) by industry. Natural gas price elasticity is also considered in the demand relationships.

The GMM[®] has its own electricity dispatch module used to determine natural gas consumption for electricity generation, which is informed by results from IPM[®]. Electric power natural gas demand is driven by projections for growth in electricity demand, natural gas-fired generating capacity, and natural gas-fired generation. Pipeline fuel natural gas use is a function of the volume of natural gas moved on the pipeline network, and lease and plant natural gas use is a function of natural gas production.

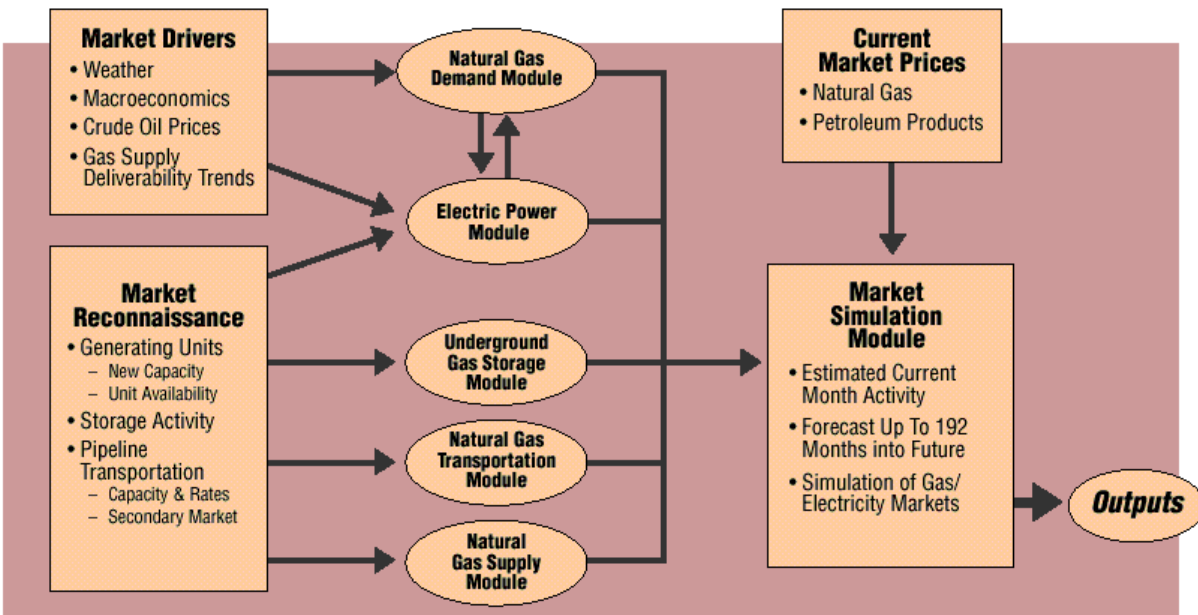
5.4.4.6 GMM[®] Node Network and Overall Model Structure

The GMM[®] network includes 118 market *nodes* and over 350 pipeline corridors.⁴ The network covers all of the United States and Canada, including Alaska and the Canadian Arctic. While Mexican natural gas production and consumption are not solved during a model run, GMM[®] does include U.S./Mexico natural gas trade at four border-crossing points.

GMM[®] consists of six modules: natural gas demand, electric power demand, gas storage, gas transportation, gas supply, and gas market simulation module, which ties all of the other modules together. Figure 5-10 shows the GMM[®] structure. The natural gas demand module estimated natural gas demand across different sectors, given economic growth, weather, and the level of price competition between natural gas and oil. The electric power demand module solves the power generation dispatch on a regional basis to determine the amount of natural gas used in power generation, which is allocated along with end-use natural gas demand to model nodes. The model nodes are tied together by a series of network links in the natural gas transportation module.

⁴ Each node represents a pricing point in the GMM natural gas network.

Figure 5-10. GMM® Structure



The natural gas supply module determines node-level natural gas deliverability or supply capability, including LNG import levels. The natural gas storage module determines the injections and withdrawals of natural gas from storage at different natural gas prices. In the market simulation module, the components of supply (i.e., natural gas deliverability, storage withdrawals, supplemental natural gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation natural gas demand, LNG exports, and Mexican exports) at each of the nodes, and natural gas prices are calculated.

IPM® contains a reduced version of GMM®, which takes the form of natural gas supply curves. Multiple GMM® runs were conducted to define the annual supply curves for natural gas for the North American electricity market, implicitly taking into account changes in demand by other sectors at different price steps. If the fundamental natural gas market assumptions change, the supply curves are regenerated to capture the impacts of those changes on available supply and cost. The incorporation of the natural gas price dynamics associated with changes in electricity demand, power plant builds, coal prices, and environmental policies is critical to providing robust forecasts. Through iterating between the IPM® and GMM® models, OEA developed a set of robust natural gas supply curves that incorporates these dynamics between electricity demand, new power plants, retirements of power plants, coal prices, and environmental policies.

6.1 Introduction

OEA analyzed the operating costs to produce Tongue River coal from the Otter Creek Mine, Poker Jim Creek–O’Dell Creek deposit, and Canyon Creek deposit, with a focus on Otter Creek Mine. The analysis indicates that the Tongue River Railroad would transport economically produced coal. This chapter also discusses Tongue River coal capital costs and financing assumptions.

This analysis highlights one difference with the three previous proposals to build the Tongue River Railroad. Namely, Powder River Basin coal prices and production costs at existing mines have increased to the level of the production costs for Tongue River coal. In particular, the rising overburden ratios in the Powder River Basin now make Tongue River coal more economically competitive than in the past.

This chapter includes the following items related to coal production costs.

- A summary of production costs for the Otter Creek Mine.
- A comparison of production costs between OEA’s estimate and productions costs estimated by the John T. Boyd Company and Norwest Corporation.
- Otter Creek Mine production costs and cost comparisons between the Norwest (2009) and Boyd (2011) reports.
- Production costs for other mines of interest.
- Capital costs for the Tongue River Railroad.
- Railroad cost of capital.
- Estimated coal mining cost of capital.

6.2 Cost Summary

As shown in Figure 6-1, OEA estimates that production costs of the Otter Creek Mine in the first year of production would be approximately \$11 per ton (2012 dollars) at the permitted capacity of 20 million tons per year. To develop this estimate, OEA primarily used information in Arch Coal’s equipment list (Montana Department of Environmental Quality 2012) to determine the capital costs associated with a new mine. Section 6.4, *Otter Creek Mine Production Costs*, provides a detailed discussion of the development of this production cost estimate. The coal mining production cost estimates increase over time and vary by the mine/deposit (i.e., Otter Creek, Poker Jim Creek–O’Dell Creek, and Canyon Creek) and by

mine size. These estimates vary because each coal deposit has intrinsic characteristics related to the amount of coal, thickness of the coal seams, and closeness of the coal seams to the surface of the ground, which directly affect the production costs. Larger mines also benefit from economies of scale. The costs increase over time as easier-to-mine deposits are depleted, leaving behind more difficult and costly deposits to mine going forward. Figure 6-2 shows the estimated production costs for the 20-year period for each of the mines that could be induced by the Tongue River Railroad.

Figure 6-1. OEA Estimate of Otter Creek Mine Production Costs for Year 1

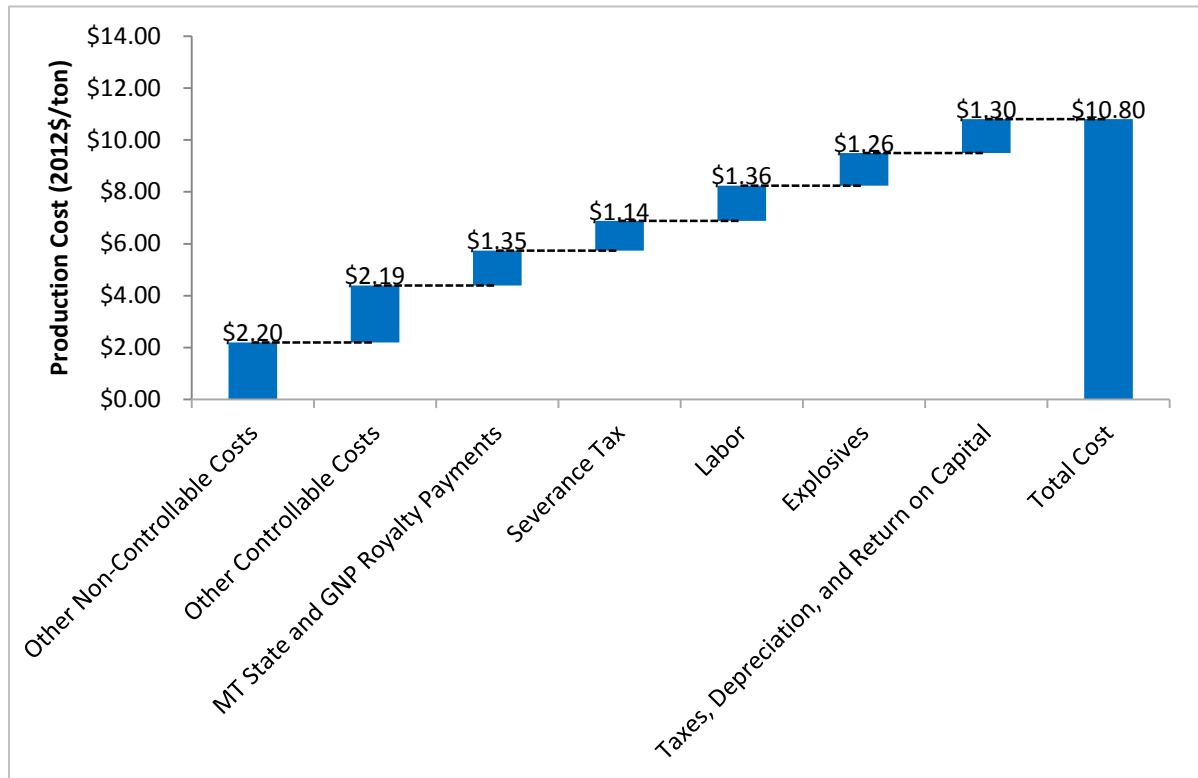
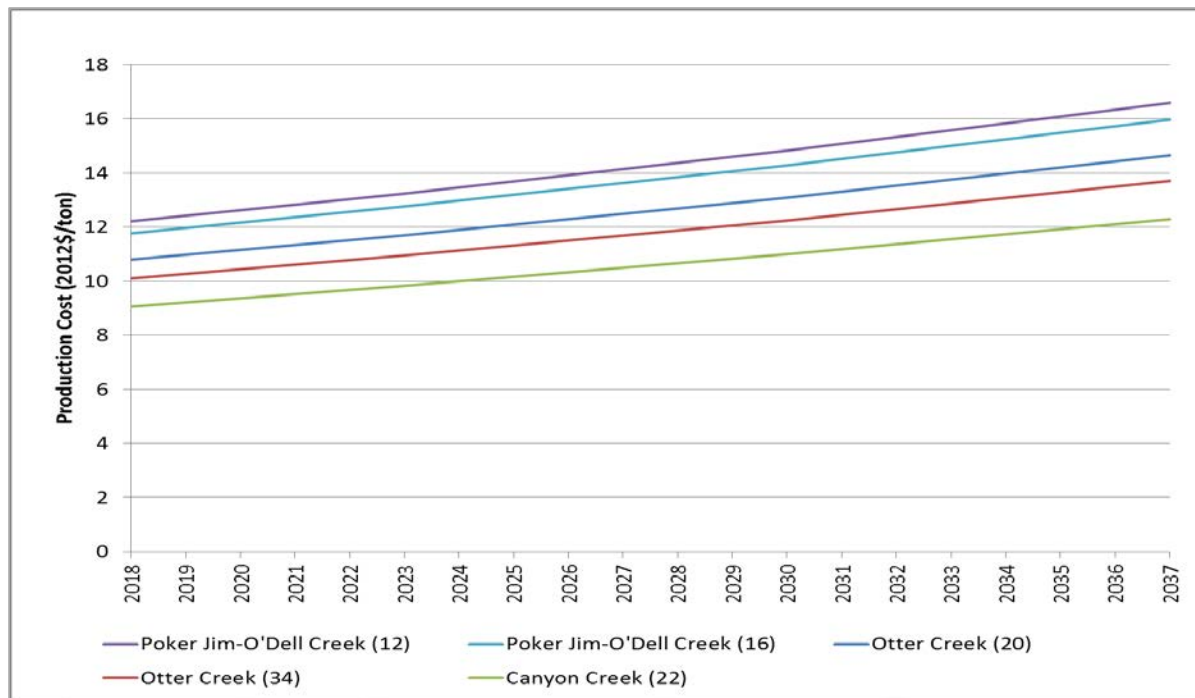


Figure 6-2. Production Cost Estimates for all Mines of Interest

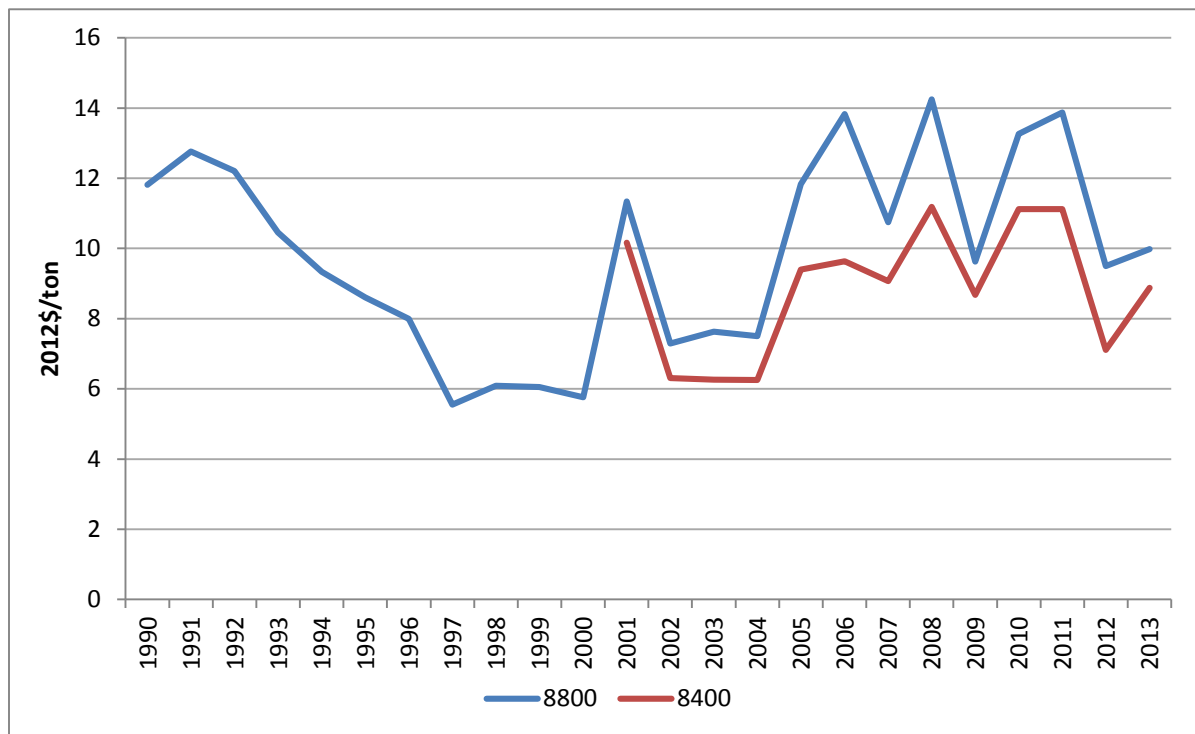


OEA estimates Otter Creek Mine coal production costs would be about \$11 per ton in 2012 dollars, starting in 2018. The following factors suggest that this production cost would enable Otter Creek Mine to be profitable, and as a result, Tongue River Railroad would have sufficient rail traffic.

- Otter Creek coal production costs of \$11 per ton are comparable to current spot coal prices (in June 2013) for Wyoming 8800 coal for June/August delivery.
- Otter Creek coal production costs of \$11 per ton are also competitive compared to Powder River Basin spot coal prices over the last 10 years (Figure 6-3).
- Otter Creek coal production costs are significantly lower than the forward prices for 2015 and 2016 deliveries, which are in the \$14 to \$15 per ton range (Vaughn pers. comm.).
- Otter Creek coal would have a lower stripping ratio than competing Wyoming 8800 coal mines. As these stripping ratios for Wyoming coal mines continue to increase to about 5 bank cubic yards (BCY) per ton, a greenfield mine¹ such as Otter Creek with an overall stripping ratio of 3 BCY per ton (removing approximately 40% less overburden for an equivalent ton of coal on average) would become economically viable. This advantage to Otter Creek Mine would be somewhat offset by the fact that Wyoming mines incurred the cost of construction many years ago, and those sunk costs are fully depreciated and do not figure into current market prices.

¹ A greenfield mine is a mine that is developed on land that has not been mined before.

Figure 6-3. Powder River Basin Spot Coal Prices, Real 2012 dollars



Nonetheless, there are cost and market uncertainties that could affect the economics of Tongue River coal mines. In addition, these costs do not include the costs to construct, operate, and maintain the proposed rail line.

6.3 Comparison of OEA, Boyd, and Norwest Production Cost Estimates

OEA compared its price estimate with a John T. Boyd Company (Boyd) report and a Norwest Corporation (Norwest) report. Prepared in 2011, the Boyd report includes an estimate of production costs for Powder River Basin mines, which was submitted to the Colorado Public Utility Commission (John T. Boyd Company 2011). Norwest prepared a report in 2009 that included an estimate of production costs for the Otter Creek Mine (Norwest 2009). OEA's coal production cost estimates are lower than Norwest's estimates. This is primarily because Norwest assumed a \$19-per-ton sales price for the coal, which inflates the taxes and royalties paid (Figure 6-4). OEA's estimates are higher than Boyd's because OEA includes recovery *of* and *on* capital, while Boyd does not; Boyd only includes recovery *of* capital (Figure 6-5).² Figures 6-4 and 6-5 differ in format primarily because Boyd does not present disaggregated costs by component. Thus, the OEA comparison is also presented at an aggregate level.

² The recovery of capital refers to earning back the initial funds invested in a project. Recovery on capital refers to net income received because of the invested capital, and is also known as "return on invested capital."

Figure 6-4. Otter Creek Production Cost Comparison for the First Year at Full Production between OEA and Norwest Estimates

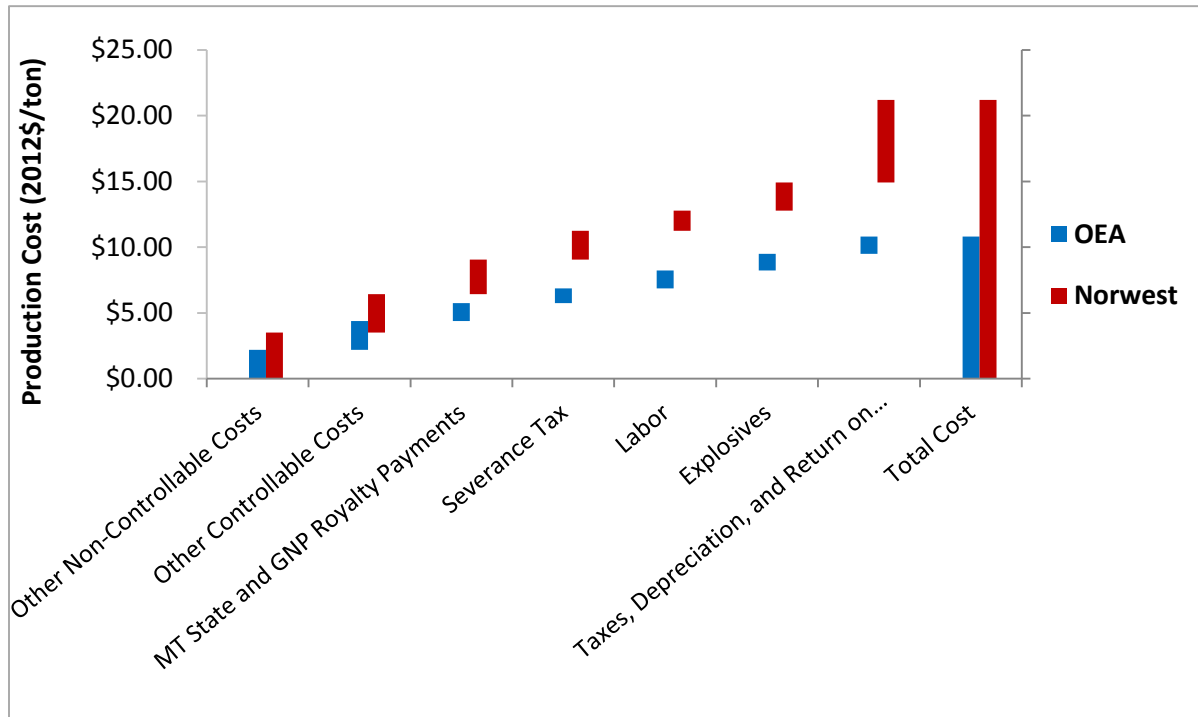
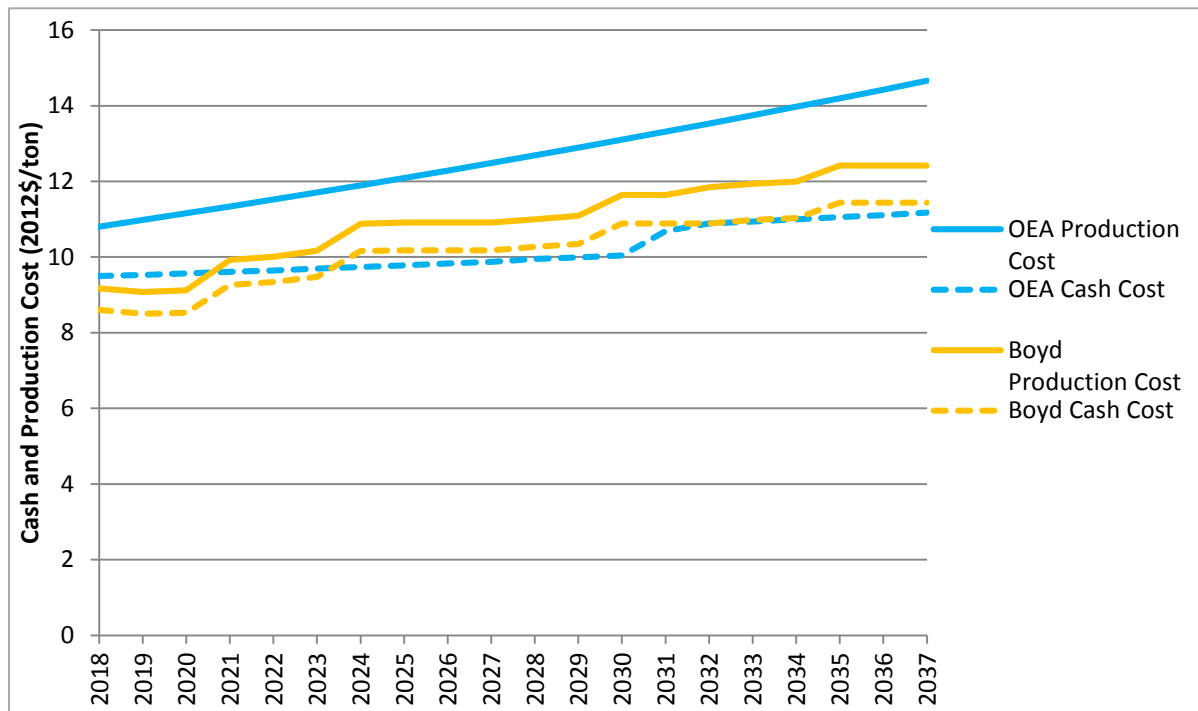


Figure 6-5. Otter Creek Cash and Production Cost Comparison between OEA and Boyd Estimates



6.4 Otter Creek Mine Production Costs

6.4.1 Overview

OEA evaluated the cost-competitiveness of Otter Creek coal using Arch Coal and Norwest as key points of comparison (Arch Coal 2012, Norwest 2009).

The production cost estimate for the Otter Creek deposit, described in detail below, is also the primary basis for the estimated production costs for the Poker Jim Creek–O’Dell Creek deposit and Canyon Creek deposit. OEA did not estimate production costs separately for the Poker Jim Creek–O’Dell Creek and Canyon Creek deposits because of the lack of detailed, deposit-specific information. However, the Poker Jim Creek–O’Dell Creek and Canyon Creek deposit mines would be similar to the Otter Creek mine in that they are all surface mines that are likely to have similar seam thicknesses and overburden ratios; therefore, using the detailed Otter Creek production costs for these other mines is appropriate. OEA selected these deposits as most likely to be mined based on factors described in Chapter 3, *Additional Coal Mining*.

The Otter Creek Mine would be a greenfield project,³ thus, OEA focused on the capital costs for the project, and the carrying costs of that investment. The carrying costs are set to provide a market return (internal rate of return [IRR] using a discounted cash flow model) on invested capital. Norwest estimates annual cash flows by year for the Otter Creek Mine (Norwest 2009: Appendix C). The OEA analysis used a similar discounted cash-flow model structure as the Norwest report. OEA used the following key sources and assumptions, which account for the difference in cost estimates compared to Norwest’s public estimate of Otter Creek costs.

- Use of the Arch Coal Mine map plan, showing sections of Otter Creek Tract 2 to be mined (Montana Department of Environmental Quality 2012).
- Use of the Arch Coal equipment list for the proposed Otter Creek Mine (Montana Department of Environmental Quality 2012).
- Updated equipment costs using 2009 InfoMine, inflated to 2012 dollars.
- Additional Montana and Powder River County-specific research of taxes, royalties, and other information.

The intent of these and other adjustments is to make the cost estimate consistent with the location, production level, and mine equipment described in the mine permit application and to update costs to 2012 levels.

³ A project at a *greenfield* site refers to the fact that the site is in a natural state and thus no one has previously developed the site.

6.4.2 Mine Map and Production

On July 25, 2012, Arch Coal filed an application for a surface coal mining permit for Otter Creek Mine with the Montana Department of Environmental Quality. The mine permit application for the Otter Creek Mine project was publicly released on March 6, 2013 (Montana Department of Environmental Quality 2012). Figure 6-6 shows the mine map plan based on the Otter Creek Mine permit application.

The Arch Coal permit application is for 20 million tons per year of production. OEA assumes the permit application tonnage would be for tons sold, not raw tons produced. The Tract 2 permit area contains about 477.5 million tons of in-place coal, as detailed in Table 6-1, which would be sufficient for at least 20 years of production, assuming more than an 84% recovery factor. Surface mines in the Powder River Basin typically have recovery factors of 95%, which would allow the mine to operate for over 22 years at 20 million tons per year. The timeframe analyzed in the EIS for the project is 20 years, concurrent with the 2018 to 2037 analysis period, as cost levels and equipment performance, both for Otter Creek and competing mines, become increasingly uncertain more than 20 years into the future. Thus, the cost model for Otter Creek Mine and the potentially induced mines assumes a 20-year mine life. A 20-year production life from Tract 2 is substantiated as reasonably possible from Arch Coal's March 6, 2013 Otter Creek Mine permit application.⁴

The Arch Coal mining plan shows that certain sections (each section is approximately 1 square mile or 640 acres) will be mined, starting at the westward boundary of Tract 2, progressing eastward. Norwest (2006) provides information on the in-place coal reserves and overburden quantities by section for this tract (Table 6-1). Using this information, it is possible to approximate the stripping ratio of overburden per ton of coal sold, expressed as BCY, for the proposed mine. Since the mine plan does not correspond exactly to section boundaries, the results are approximate. The coal reserves can be roughly divided into western and eastern portions, with the western side to be mined first. Norwest used this information in the mine production cost model to estimate the overburden quantities for the early and later mining. A 20-year production life from Tract 2 is substantiated as reasonably possible from Arch Coal's March 6, 2013 Otter Creek Mine permit application.⁵

⁴ "The mine plan is designed to produce approximately 20 million tons of coal annually for 17- 20 years." Otter Creek Permit Application, 17.24.308: Operations Plan, Exhibit 308A. March 6, 2013.

⁵ "The mine plan is designed to produce approximately 20 million tons of coal annually for 17- 20 years." Otter Creek Permit Application, 17.24.308: Operations Plan, Exhibit 308A. March 6, 2013.

Figure 6-6. Otter Creek Mine Map Plan

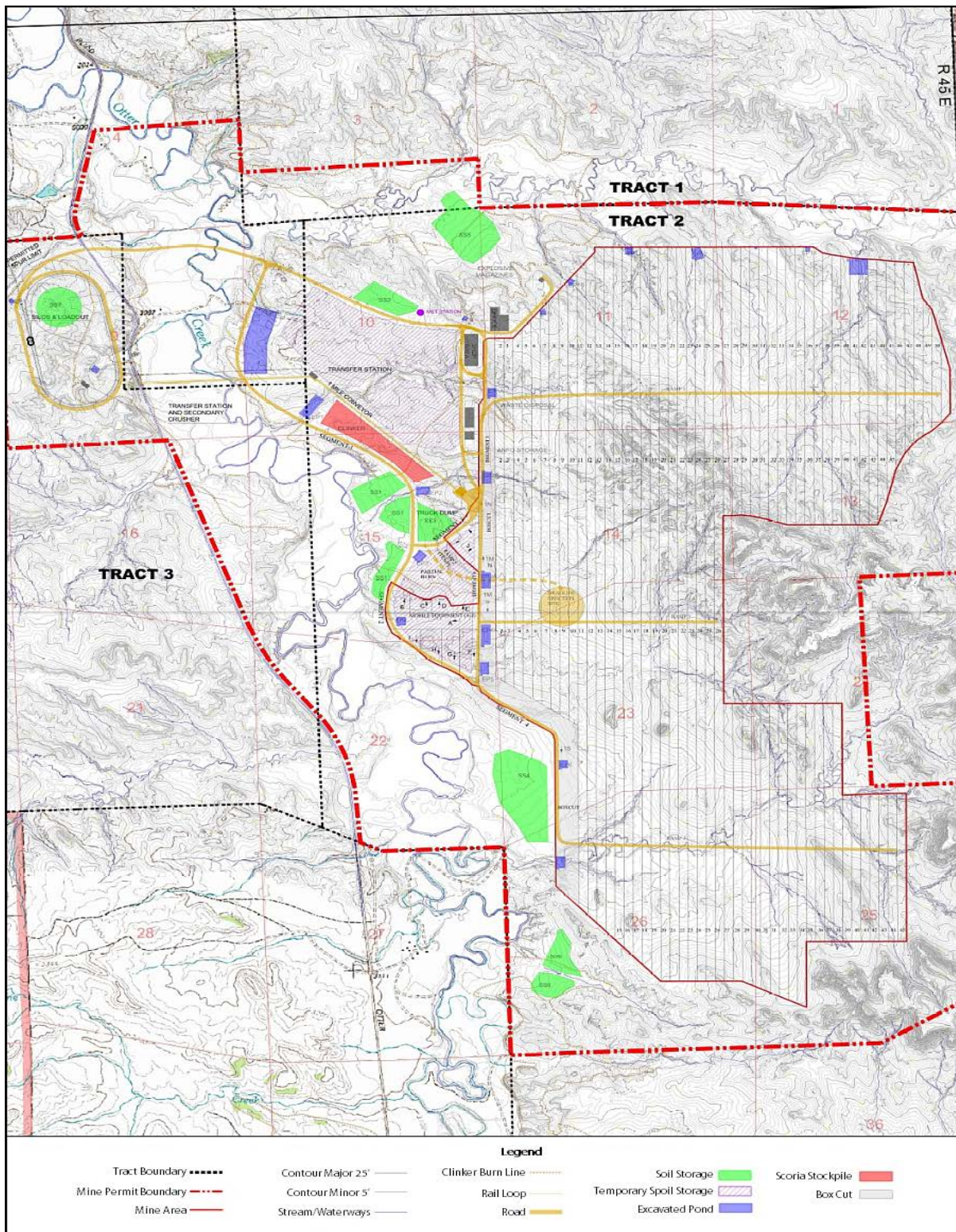


Table 6-1. Otter Creek Mine Tract 2 Available Resources

Section No.	Waste BCY	Coal tons (in-place)	Recovery Factor (%)	Coal Tons (sold)	Stripping Ratio (BCY/tons sold)
Western portion of Tract 2: first group in sequence of mining					
11	174,429,347	69,009,462	95	65,558,989	2.66
14	154,326,247	57,340,481	95	54,473,457	2.83
23	210,664,617	80,099,553	95	76,094,575	2.77
26	193,349,695	71,587,040	95	68,007,688	2.84
Total	732,769,906	278,036,536	95	264,134,709	2.77
Eastern portion of Tract 2: second group in sequence of mining					
12	156,970,046	73,256,900	95	69,594,055	2.26
13	211,586,426	55,500,331	95	52,725,314	4.01
25	288,764,953	70,723,718	95	67,187,532	4.30
Total	657,321,425	199,480,949	95	189,506,902	3.47
Total resources available in Tract 2					
All	1,390,091,331	477,517,485	95	453,641,611	3.06
Notes: BCY = bank cubic yards					

Norwest assumed the coal tons reported in its 2006 report to be in-place tons.⁶ Using the same 95% recovery factor as in the Norwest 2009 report, total saleable coal for the relevant sections is about 453.6 million tons. For the 20-year production cost model (analysis period 2018 to 2037), total coal sold is 400 million tons, total coal produced is 421 million tons, and the overall stripping ratio is calculated at 3.01. This is slightly less than the overall stripping ratio of 3.06 shown above in Table 6-1 because the entirety of the Tract 2 coal would not be produced, and some of the coal in the higher stripping-ratio sections in the eastern portion of Tract 2 would remain undeveloped.

6.4.3 Capital Costs

6.4.3.1 Equipment

Table 6-2 lists the required equipment for the Otter Creek Mine from the Arch Coal Mine permit application.⁷ For the specified equipment, OEA obtained capital cost estimates from the publication *Mine and Mill Equipment Costs: An Estimator's Guide, Surface Mining Equipment, 2009* (InfoMine USA 2009). Norwest used the 2007 edition of this publication for its 2009 report. OEA adjusted these equipment cost estimates to 2012 prices using a published U.S. Bureau of Labor Statistics (BLS) index (BLS 11-2) of construction equipment costs (U.S. Department of Labor 2008, 2009, 2012). For the mine facilities (including coal loading), which are not included in the Arch Coal Mine application, OEA used the estimates

⁶ In-place coal is undisturbed coal that is in the ground. The weight of in-place coal tonnage does not differ from the same tonnage of coal that is removed from the ground. The volume of in-place coal, however, is indeed less than the volume of the same tonnage of mined coal.

⁷ Otter Creek Permit Application, 17.24.308: Operations Plan, Exhibit 308B. March 6, 2013.

from the Norwest 2009 report and adjusted those 2008 dollars costs to 2012 dollar-levels using a BLS index of industrial construction costs (BLS 236211) (U.S. Department of Labor 2008, 2009, 2012).

Table 6-2. Arch Coal Otter Creek Mine Exhibit 308B List of Equipment^a

Quantity	Equipment
1	100–120-cubic-yard class dragline
1	53-cubic-yard electric shovel
1–2	Electric drills
1–2	Large class front end loader (38 cubic yards)
8–10	Large class haul truck (240 cubic yards)
2–4	24G graders
3–5	Large class dozers (Cat D-11 size)
2–5	Large class scrapers (Cat 651 size)
1–3	Water truck
1–2	Rubber tired dozer
0–1	Reclamation tractor
Notes:	
^a Soil preparation and seeding implements: disk, subsoil plow, roller harrow, seeder. Other miscellaneous support equipment too numerous to mention.	

A vast majority of the total equipment costs for surface coal mining comprises the dragline⁸ and the truck and shovel fleet. Table 6-3 lists the relevant InfoMine equipment and equipment costs in 2009 dollars, the inflation index for construction machinery (BLS 11-2) (U.S. Department of Labor 2008, 2009, 2012) used to inflate from 2009 dollars to 2012 dollars, and the final 2012 dollars equipment costs on a per unit basis assumed for each of the key pieces of equipment from the Arch Coal equipment list.

⁸ A dragline excavator is piece of large heavy equipment used in surface mining to remove overburden.

Table 6-3. Otter Creek Mine Equipment and Equipment Costs

InfoMine Equipment	InfoMine Equipment Cost (Million 2009\$)	Arch Coal Equipment	Assumed Equipment Cost (Million 2009\$)	Construction Machinery Inflation Index (2009\$–2012\$)	Estimated Equipment Cost (Million 2012\$)
70-110 CY Dragline	93.00	110 CY dragline	109.00	1.07	116.96
110-150-CY Dragline	125.00				
55 CY Cable Rock Shovel	12.22	53 CY cable rock shovel	12.22	1.07	13.11
33 CY Wheel Loader	5.92	38 CY wheel loader	6.78	1.07	7.28
53 CY Wheel Loader	7.64				
241 CY (314 short ton) Truck	3.63	240 CY truck	3.63	1.07	3.89
Notes: CY = cubic yards					

The Arch Coal equipment list also mentions “other miscellaneous support equipment too numerous to mention.” Norwest’s estimate includes these additional mobile equipment costs, but it does not include any details. OEA, therefore, assumed the same 5% share of additional mobile equipment costs to total mobile equipment costs as Norwest, resulting in an estimate of \$9.094 million in 2012 dollars for additional mobile equipment costs.

OEA used the same reclamation equipment cost assumptions as Norwest (2009) but scaled the costs by acreage. Therefore, further mentions of the Norwest report refer to the Norwest 2009 report, unless explicitly stated as referring to the Norwest 2006 report. For the Norwest Logical Mining Unit (LMU) 5 Otter Creek Mine production cost estimate, both Tract 1 and Tract 2 are included for coal sales of 21.2 million tons per year. The currently proposed 20 million tons per year mine plan includes only Tract 2. The acreage of Tract 2 as a share of Tract 1 and Tract 2 is 53%. OEA applied that share to the Norwest reclamation equipment costs because the amount of reclamation equipment is proportional to the area of land to be reclaimed. OEA then converted the Norwest reclamation equipment costs into to 2012 dollars using the index for construction machinery described above and arrived at an estimate of reclamation equipment costs of \$6.365 million in 2012 dollars.

6.4.3.2 Fixed Facilities and Other Capital Costs

Other capital costs include working capital, permitting and engineering, exploration drilling, mine facilities, coal handling plant, and miscellaneous equipment and supplies.

OEA assumed the same working capital assumptions as Norwest at 3 months of the first year’s total controllable cash production costs. This amounts to \$24.208 million in 2012

dollars. OEA assumed the same total capital costs as Norwest for permitting and engineering, exploration drilling, mine facilities, coal handling plant, and miscellaneous equipment and supplies. Norwest splits the total cost for the above capital costs evenly between LMU 5 and LMU 6, Tract 1, Tract 2, and Tract 3, respectively. The total capital cost for the mine facilities and the coal handling plant—estimated at \$99 million in 2008 dollars—represents the cost for fixed facilities with a coal-handling capacity of 34 million tons per year. The proposed production in the Otter Creek Mine permit application is about 60% of the 34 million tons per year at 20 million tons per year, but fixed facilities costs are not scalable in a linear fashion because of nonlinear economies of scale. OEA conservatively assumed that a plant with a capacity of 34 million tons per year would be built to allow for possible expansion in coal production capability. OEA adjusted these total capital costs to 2012 dollars using the BLS index for new industrial building construction (NAICS 236211) (U.S. Department of Labor 2008, 2009, 2012) to arrive at a total capital cost of \$104.67 million in 2012 dollars for these fixed facilities.

6.4.4 Operating Costs

6.4.4.1 Labor

OEA adjusted the Norwest wage and benefit hourly costs to 2012 levels using the ratio of the 2012 to 2008 average wage paid in Montana to the construction equipment operators index (U.S. Department of Labor 2008, 2009, 2012). The index increased 26% from mid-2008 to mid-2012. Specific coal mining wage rates are not publicly available. Norwest estimates the total labor cost to be \$44.33 per hour in 2008 dollars. This estimate is a weighted average hourly wage cost for union and salaried employees, including about 50% of the wage cost for benefits and assuming a distribution of 443 union employees and 95 salaried employees. OEA used an inflated 2012 weighted average hourly wage cost of \$55.80 per hour, including benefits.

The required labor per ton is based on the worker-hours required per *unit of production*, which is the total of the overburden BCY and the coal tons. The coal produced per worker-hour is based on the average productivity of Wyoming coal mines (measured in tons/worker-hour) and reported by the U.S. Energy Information Agency for 2011 for all Wyoming mines. Since these data include some mines that are not in the Powder River Basin and that may have lower productivity, the State of Wyoming average is probably slightly low as compared to the Powder River Basin average.

Norwest uses a labor productivity estimate for Otter Creek of 31 tons per labor-hour, taken from the 2000 to 2007 average for similar Montana mines. OEA used the same estimate of 31 tons per hour, which is consistent with the U.S. Energy Information Administration's 2011 Coal Annual for the average productivity for Wyoming surface mines (U.S. Energy Information Agency 2012). OEA used the productivity of Wyoming surface mines as a reference point because there are significantly more surface mines in Wyoming than in Montana.

The BLM website provides recent Wyoming Powder River Basin coal leases by application. Existing mines that have depleted current resources and seek an expansion to continue production can acquire new federal leases. Recent coal lease submissions for the Wyoming Powder River Basin mines show stripping ratios around 4 to 5 BCY per ton (Bureau of Land Management 2013). The 2011 average stripping ratio of Wyoming Powder River Basin mines reported by the Wyoming Geological Survey (2013) is approximately 4 BCY per ton. At a stripping ratio of 4 BCY per ton, the total units of production removed per ton of coal is the stripping ratio plus one, or five units of production; i.e., (BCY plus one) per ton.

With a productivity of 31 tons per hour, assuming a stripping ratio of 4 BCY per ton, this is equivalent to 155 units of production per hour, (i.e., 31 times $[4 + 1]$). At equivalent units of 155 units of production per hour and at a cost of \$55.80 per hour, Otter Creek Mine's estimated labor cost is \$0.36 per unit of production.

6.4.4.2 Nonlabor Operating Costs

Mine operating costs include replacement parts, equipment overhaul, diesel fuel, lubricants, and other supplies. The estimates and assumptions for these operating costs are based on the Norwest 2009 study. These operating costs are largely proportional to the number of mining machines and their hours of operation. Thus, Norwest translated the BCY or BCY per ton costs into cost per machine-hour for dragline, truck-shovel equipment, and coal haulage. The number of machine hours in the Norwest analysis could be calculated because it lists the number of machines and the assumed operating hours. The number of machine hours for OEA's estimate is based on the Arch Coal Mine permit equipment list (Table 6-2) and an assumed annual operating hours, taking into account downtime for factors such as maintenance and move time. Total operating costs (dollars per hour multiplied by hours of operation) were then divided by the amount of overburden handled (in BCY) to determine a cost per BCY. Operating costs were adjusted to year 2012 dollars with a published BLS Intermediate Materials Supplies and Components inflation index that includes an oil price component.

Norwest assumes three draglines operating for 6,000 hours per year for its 22-million-tons-per-year LMU 5 mine. The dragline removes about 76% of overburden and the truck-shovel (T/S) fleet removes the remaining 24%, on average for the life of the LMU 5 mine. Dragline overburden removal for a typical year (i.e., year 3) is about 56 million BCY. Year 3 is typical because it is the first year where full production capacity is reached at 21.2 million tons per year coal sold, and the stripping ratio is greater than 3 BCY per ton. Norwest estimates the dragline operating cost to be \$0.23 per BCY. Thus, the total hourly dragline operating cost for the three draglines used by Norwest is \$2,136 per hour, which is \$712 per hour for one dragline. OEA assumed one dragline, as specified in the Arch Coal equipment list, operating at 7,560 hours per year, which is 50 out of 52 weeks, 24 hours per day, with 10% maintenance and downtime factor for the 50 operational weeks. OEA's model of the mine cost has fewer draglines operating for more hours per year. Thus, OEA's yearly dragline overburden removal cost totals \$5.38 million (\$712 per hour multiplied by 7,560

hours), or an equivalent dollars-per-BCY cost of \$0.10 per BCY. This estimate is in 2012 dollars and takes into account the BLS index for intermediate materials supplies and components.

For the truck and shovel fleet, a similar calculation can be applied. Norwest assumes two truck and shovel spreads with 10 overburden trucks and two shovels operating at 5,000 hours per year, an overburden removal cost of \$0.71 per BCY and about 17 million BCY removed in a typical year for the Norwest T/S fleet. With those assumptions, OEA arrived at an hourly operating cost of \$222 per hour for truck and shovel fleet operation. The 10 trucks in Arch Coal's equipment list are split five for overburden handling, with one electric shovel, and five for coal handling (i.e., using the same truck and shovel ratio as Norwest), so that there would be only five trucks operating at 7,560 hours per year. Combining the hours worked and dollar-per-hour operating cost yielded an overall truck and shovel overburden removal cost of \$0.50 per BCY. This estimate is in 2012 dollars and takes into account the BLS index for intermediate materials supplies and components.

Norwest similarly adjusts a \$0.76-per-ton coal-loading haulage cost to a dollars-per-hour operating cost by taking its ten 240-ton coal trucks operating at 5,500 hours per truck-year and its steady state LMU 5 tons sold at 21.2 million tons per year for \$293 per hour. In OEA's analysis, there are five 240-cubic yard coal trucks operating at 7,560 hours per year, which yields an overall adjusted coal loading-haulage cost of \$0.53 per ton. OEA's estimate is in 2012 dollars and takes into account the BLS index for intermediate materials supplies and components.

For the remaining dollars-per ton nonlabor operating costs (i.e., other support equipment, other supplies and services, coal handling plant, and reclamation), OEA used the same operating costs as Norwest 2009, inflated to 2012 price levels using the BLS index for intermediate materials supplies and components.

6.4.4.3 Explosives

OEA determined explosives costs for both overburden and coal blasting based on the pounds of explosive per BCY or per ton (*powder factor*) from the Norwest study. OEA applied this powder factor ratio to the overburden and coal quantities. OEA obtained price estimates for explosives (ammonium nitrate/fuel oil, emulsion, explosives accessories) from Norwest and updated to 2012 levels using published BLS indices for explosives (06902) and nitrogenates (06-52-01) (U.S. Department of Labor 2008, 2009, 2012).

The weighted average cost for explosives with accessories would be \$0.54 per pound, assuming Norwest assumptions of ammonium nitrate/fuel oil cost at \$0.44 per pound, an emulsion cost of \$0.74 per pound, a share of 90% ammonium nitrate/fuel oil and 10% emulsion, and a factor of 15% for explosives accessories. The data on explosives requirements were based on Norwest's estimates of a dragline powder factor of 0.6 pound per BCY overburden, a truck and shovel powder factor of 1.0 pound per BCY overburden, and a coal powder factor is 0.3 pound per ton. Weighted over the 20-year life of the Otter Creek Mine producing at 20 million tons per year, with an overall stripping ratio of 3.01 BCY per ton and the same 76% dragline, 24% T/S overburden removal split as Norwest, this would yield about 920 million BCY overburden to be blasted for dragline removal, 285 million BCY overburden to be blasted for T/S removal, and 400 million tons to be blasted for coal handling. OEA calculated a weighted average explosives cost of \$0.33 per unit in 2012 dollars using an inflated average of BLS explosives and nitrogenates indices. This is similar to Norwest's calculated \$0.37 per unit, but the difference arises because coal is a higher portion of the total units (tons of coal plus bank cubic yards of overburden) in the current model than in the Norwest analysis. OEA's estimate is slightly less than the Norwest estimate because the Norwest analysis used a higher stripping ratio than the more recent stripping ratio projections from Arch Coal.

6.4.4.4 *Ad Valorem Taxes, Royalties, Fees, and Overhead*

OEA computed costs for coal taxes and royalties consistent with the Norwest study, with the exception of the treatment of property taxes. Montana tax regulations provide for a calculation based on *adjusted revenue*. The adjusted revenue is defined as contract sales price, or free on board (FOB) mine gross revenue (tons of coal sold multiplied by selling price) less the following deductions: federal black lung excise tax, Montana severance tax, Montana gross receipts tax, federal reclamation fees, Montana resource indemnity trust tax, and Montana and Great Northern Plains royalty payments (Montana Department of Revenue 2009). This is consistent with Norwest's treatment of adjusted revenue or contract sales price for calculation of the severance, gross receipts, and resource indemnity trust taxes. To avoid an iterative approach to determining the adjusted revenue—iterative because the adjusted revenue is used to calculate taxes and royalties but those royalties and taxes are also used to calculate adjusted revenue—OEA approximated the adjusted revenue stream using Norwest's average ratio of adjusted revenue to total revenue and multiplied that ratio by the total revenue figures. Realization is defined as coal sales price multiplied by coal tonnage, or simply total revenue. Table 6-4 references this realization or total revenue figure and details the tax and royalty items and their applications.

Table 6-4. Ad Valorem Taxes, Royalties, and Fees

Item	Method
Federal Black Lung Tax	4.4% of realization up to maximum \$0.55 per ton
Montana Severance Tax	15.0% of realization plus \$0.15 per ton, off “adjusted revenue”
Montana Gross Receipts Tax	5.0% of realization, off “adjusted revenue”
Federal Reclamation Fees	\$0.35 per ton
MT Resource Indemnity Trust Tax	0.4% of realization, off “adjusted revenue”
Royalty Montana State Land	12.5% of realization
Royalty Great Northern Property Land	Assuming same royalty % as Montana State at 12.5%
Property Taxes	Split for Heavy Equipment and Fixed Facilities
Montana Lease Rental Fee	Fixed annual payment of \$19,000 per year
Reclamation Bond Premium	Fixed annual payment of \$1,500,000 per year
General Insurance	Cost of \$0.012 per unit of production
Corporate Overhead + Joint Facilities	Cost of \$0.108 per unit of production
Other	Cost of \$0.060 per unit of production

OEA updated the property tax estimates to reflect the split for heavy equipment and fixed facilities (Ponozzo pers. comm.). Table 6-5 shows the calculated property tax rates as a percentage of the asset base is documented below and summarized in Table 6-5.

Table 6-5. Property Tax Rate as Percentage (%) of Asset Base for Heavy Equipment and Fixed Facilities

Year	Heavy Equipment 20-year life	Heavy Equipment 10-year life	Fixed Facilities
1	1.05	1.05	0.85
2	0.85	0.85	0.82
3	0.77	0.77	0.80
4	0.73	0.73	0.78
5	0.63	0.63	0.76
6	0.58	0.58	0.74
7	0.56	0.56	0.72
8	0.48	0.48	0.70
9	0.43	0.43	0.68
10	0.41	0.41	0.66
11	0.38	1.05	0.63
12	0.35	0.85	0.61
13	0.30	0.77	0.59
14	0.30	0.73	0.57
15	0.25	0.63	0.55
16	0.26	0.58	0.53
17	0.26	0.56	0.51
18	0.26	0.48	0.49
19	0.21	0.43	0.46
20	0.21	0.41	0.44

OEA estimated heavy equipment property taxes by multiplying heavy equipment assets by 3%, the heavy equipment depreciation schedule (Montana Department of Revenue 2013), and a tax rate for Powder River County of 0.436 (Ponozzo pers. comm.). The Montana regulations provide for tax based on the *percent good*, equivalent to original cost less depreciation. The heavy equipment depreciation schedule is split for 20-year life equipment (dragline and rock shovel) and 10-year life equipment (trucks, loader, other mobile equipment, and reclamation equipment), as assumed by Norwest. In aggregate, heavy equipment includes about \$200 million in assets.

OEA determined fixed facilities property taxes by multiplying fixed facilities assets by 2.47%, the fixed facilities depreciation schedule, the Powder River County tax rate of 0.436, and an adjustment factor of 78.5% (Ponozzo pers. comm.). OEA assumed the fixed facilities depreciation schedule to be straight-line depreciated assuming a 40-year life, corresponding to a constant decrease of 2.5% of the original asset value each year. Fixed facilities include mine facilities and the coal handling plant, about \$100 million in assets.

6.4.5 Financial Modeling Assumptions

The coal price in the Otter Creek discounted cash flow model was determined to be at a level that would provide the producer with a discounted after-tax cash flow, constant-year dollar internal rate of return (IRR) of 8.3%. Thus, this assumes the investment in the Otter Creek Mine would not be economical if it did not expect a minimum selling price equivalent to the price determined by an IRR of 8.3%. Thus, OEA set the production cost as the selling price with an IRR of 8.3%. Norwest used a similar method but assumed a coal price of \$19.82 per ton based on subtracting the difference in transportation costs from estimated delivered costs. (Norwest 2009:3-10). Section 6.10, *Coal Mining Cost of Capital* provides details on OEA's 8.3% IRR assumption.

Statutory income tax rates are 35% federal and 6.75% state (Montana). Norwest used income tax rates at 18.6% federal and 3.4% state, likely because its analysis took into account additional deductions and tax benefits. OEA assumed the same overall federal and state income tax rate as Norwest (approximately half the statutory rates). The assumption of an income tax rate about half that of the statutory rates may be an overestimate, as Arch Coal reported negative income taxes in 2010 and 2011 (Arch Coal 2012).

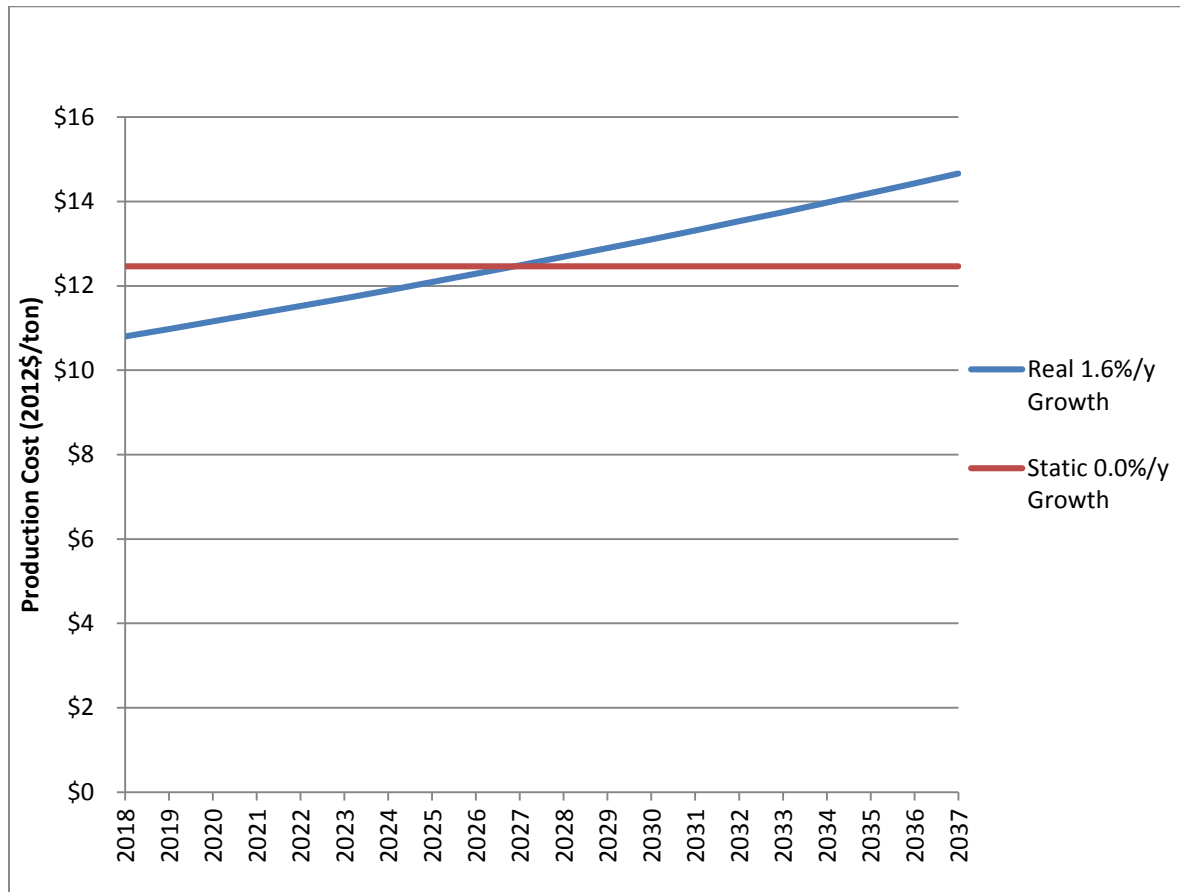
Depreciation for calculating income taxes was handled in a simplified way: straight-line 10 years for mobile equipment (consistent with Norwest's 10-year replacement assumption) and 20 years for dragline and mine facilities.

6.4.6 Production Cost Estimate

OEA's production cost estimate started with Norwest's discounted cash flow model and used many of its assumptions, as detailed previously. OEA's analysis, however, revises Norwest's calculations to take into account updated mine developments and more current figures,

including the Arch Coal Mine map plan, the Arch Coal equipment list, updated equipment costs, and updated taxes and royalty figures. Assuming a static real dollar selling price for the 20-year life of the mine (2018 to 2037 analysis period), Otter Creek production costs are estimated to be \$12 per ton in 2012 dollars. This is reflected in the Static 0.0%/y Growth line in Figure 6-7. An estimate with static growth (i.e., a single, leveled cost) is calculated to provide a point of comparison with the Norwest estimate.

Figure 6-7. Projection of Otter Creek Mine Production Cost with Real and Static Growth



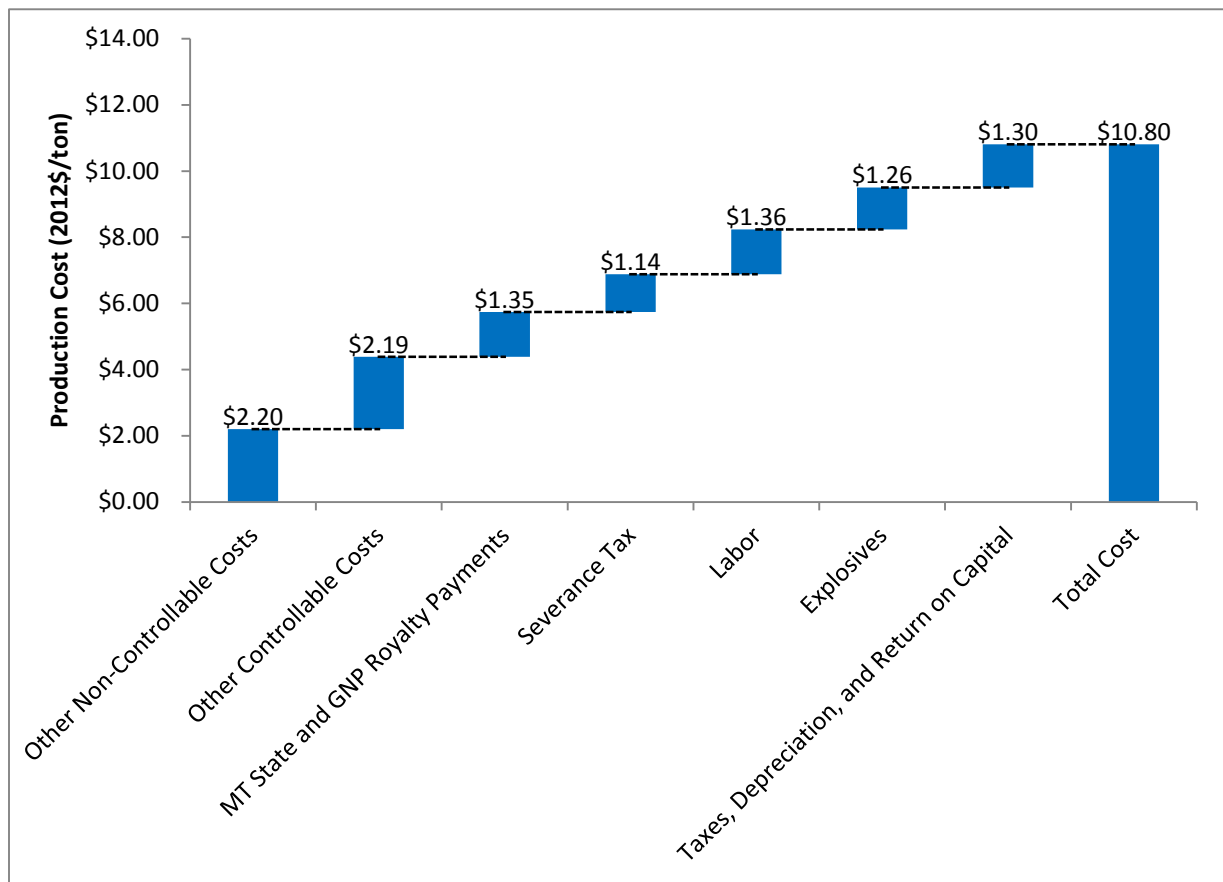
If the mine owner expects prices to be increasing faster than general inflation over time, then the first-year price required to justify the overall investment would be lower, because the IRR calculation takes into account the time value of money. Given Boyd's projections of increasing production costs at competing mines, and the fact that stripping ratios will continue to increase, the expectation of rising prices over time is reasonable. Production costs at Otter Creek Mine would likely rise over time as the higher stripping ratio reserves are mined later in the operating life. Real growth in costs of mining at competing Powder River Basin mines of about 1.6% per year was estimated by Boyd (2011) (1.61% per year for Otter Creek Mine and 1.62% per year for all Powder River Basin mines, determined by the estimated compound annual cost growth rate between 2018 and 2037). The cost of production for Otter Creek Mine was determined by assuming the selling price would

increase at the projected rate of Powder River Basin cost increases: 1.6% annually. The resulting selling price rises over time, starting at about \$11 per ton in year 1, rising to \$15 per ton in year 20 (also in real 2012 dollars). This selling price is the estimate total production cost that includes the cash costs, depreciation, and return on and of capital (Figure 6-7). The real growth estimate line in Figure 6-7 does not cross the static estimate line at the midpoint (year 10) because the production costs in the early years would have more influence on IRR than the production costs in the later years. This estimated production cost with a rising real price is the preferred measure, which accurately reflects the projected increase in future stripping ratios.

Current prices (June 2013) for Wyoming 8800 coal, June/August delivery are about \$11 per ton. Estimated prices for 2015 and 2016 deliveries are in the \$14 to \$15 per ton range (Vaughn pers. comm.). Currently operating mines producing Wyoming 8800 coal incurred the cost of constructing mine facilities many years ago, and those sunk costs are fully depreciated and do not figure into current market prices. Most of the Wyoming 8800 mines have higher stripping ratios than 4 BCY per ton (Bureau of Land Management 2013). As stripping ratios continue to increase over the next few years to about 5 BCY per ton, a greenfield mine with an overall stripping ratio of 3 BCY per ton (removing approximately 40% less overburden for an equivalent ton of coal on average) becomes economically viable. The OEA estimate shows prices of about \$11 per ton in 2012 dollars starting in 2018.

Figure 6-8 highlights a breakout of the major cost components in year 1 of production, assuming growth in real prices. The four largest cash cost components include royalty payments, severance tax, labor, and explosives, which is analogous to the cost structure at existing surface mine operations. The Taxes, Depreciation, and Return on Capital cost component represents the cost of income taxes, the cost of recovering the initial capital expenditures, and the cost of the return on investment. Other noncontrollable costs include the black lung excise tax, gross receipts tax, reclamation fees, resource indemnity trust tax, property taxes, lease rental fee, reclamation bonding (premium), general insurance, corporate overhead plus joint facilities, and other. Other controllable costs include overburden removal (dragline and T/S), coal loading-haulage, coal-handling plant, reclamation, other support equipment, and other supplies and services (Table 6-6).

Figure 6-8. Estimate of Otter Creek Mine Production Costs in Year 1



6.5 Otter Creek Mine Production Cost Comparison: Norwest 2009

6.5.1 Overview

The difference in production costs between the OEA estimate and the Norwest 2009 LMU 5 estimate is largely the result of cost differences in equipment. The OEA estimate includes about \$400 million using Arch Coal's equipment list; whereas, the Norwest estimate includes about \$1 billion. The timeframe for these equipment cost estimates is a 20-year mine life in OEA's estimate (2018 to 2037) and a 40-year mine life in Norwest's estimate. A similar 20-year mine life comparison in the Norwest estimate would total about \$800 million in equipment costs, which would still be twice that of the OEA estimate.

Table 6-6. Discounted Cash Flow, Internal Rate of Return 20-year Otter Creek Mine Model

Otter Creek Tract 2, 2012\$																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																								
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Otter Creek Tract 2, 2012\$	Basis	Units	Year-5	Year-4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Totals
from Coal Sales																												
Adjusted Revenue for Selected Taxes	69%							148906	151317	153766	156256	158786	161357	163969	166624	169322	172063	174849	177680	180556	183480	186450	189469	192536	195654	198821	202040	3,483,900
CASH PRODUCTION COSTS																												
CONTROLLABLE COSTS																												
Labor	0.36	\$/UN IT	1.44	\$/TO N				27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	27,174	31,140	32,173	32,173	32,173	32,173	32,173	32,173	577,442
Equipment, Materials and Supplies																												
OB Removal Dragline	0.10	\$/BC Y						4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,170	4,998	5,214	5,214	5,214	5,214	5,214	5,214	90,495
OB Truck - Shovel	0.50	\$/BC Y						6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	6,518	7,812	8,149	8,149	8,149	8,149	8,149	8,149	141,438
Explosives	0.33	\$/UN IT						25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	25,275	28,964	29,925	29,925	29,925	29,925	29,925	29,925	537,088
Coal Loading - Haulage	0.53	\$/TO N						10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	212,857
Other Support Equipment	0.44	\$/TO N						8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	8,965	179,307
Other Supplies and Services	0.12	\$/TO N						2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	48,902
Coal Handling Plant	0.19	\$/TO N						3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	3,871	77,428
Reclamat ion	0.35	\$/TO N						7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	7,132	142,631
Total Controllabl e Costs								96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	96,193	105970	108518	108518	108518	108518	108518	108518	2,007,587
\$/SALES TON								4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	4.81	5.30	5.43	5.43	5.43	5.43	5.43	5.43	5.02
NON-CONTROLLABLE COSTS																												

Otter Creek Tract 2, 2012\$	Basis	Units	Year-5	Year-4	Year-3	Year-2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Totals
Black Lung Tax	0.55	\$/Ton						11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	220,000	
MT Severance Tax	15.0	% of Revenue	0.15	\$/Ton Adder		22,786	23,147	23,515	23,888	24,268	24,653	25,045	25,444	25,848	26,259	26,677	27,102	27,533	27,972	28,418	28,870	29,330	29,798	30,273	30,756	531,585	MT Svrnc. Tax	
MT Gross Receipts Tax	5.0	% of Revenue					7,445	7,566	7,688	7,813	7,939	8,068	8,198	8,331	8,466	8,603	8,742	8,884	9,028	9,174	9,323	9,473	9,627	9,783	9,941	10,102	174,195	
Federal Reclamation Fees	0.35	\$/Ton					7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	140,000	
MT Resource Indemnity Trust Tax	0.4	% of Revenue					596	605	615	625	635	645	656	666	677	688	699	711	722	734	746	758	770	783	795	808	13,936	
Royalty Payments: MT State	12.5	% of Revenue	49.8%	Share of land		13,456	13,674	13,895	14,120	14,349	14,581	14,817	15,057	15,301	15,548	15,800	16,056	16,316	16,580	16,849	17,121	17,399	17,680	17,966	18,257	314,822	Royalty PaymentsMT State	
Royalty Payments: Great Northern Plains	12.5	% of Revenue	50.2%	Share of land		13,557	13,776	13,999	14,226	14,456	14,690	14,928	15,170	15,415	15,665	15,919	16,176	16,438	16,704	16,975	17,250	17,529	17,813	18,101	18,394	317,180	Royalty PaymentsGreat Northern Plains	
Property Taxes - Heavy Equipment 20-yr life	130,077	Asset Base					1,361	1,106	1,004	953	817	749	732	630	561	527	493	459	391	391	323	340	340	340	272	272	12,063	
Property Taxes - Heavy Equipment 10-yr life	61,666	Asset Base					645	524	476	452	387	355	347	298	266	250	645	524	476	452	387	355	347	298	266	250	8,001	
Property Taxes - Fixed Facilities	104,761	Asset Base					886	863	841	819	797	775	753	731	709	686	664	642	620	598	576	554	531	509	487	465	13,506	
Lease Rental Fee	19	\$000s					19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	386	
Reclamation Bonding (premium)	1,500	\$000s					1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	30,000	
General Insurance	0.012	\$/Unit					906	906	906	906	906	906	906	906	906	906	906	906	906	1,038	1,072	1,072	1,072	1,072	1,072	1,072	19,248	
Corporate Overhead +	0.108	\$/Unit					8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	8,152	9,342	9,652	9,652	9,652	9,652	9,652	9,652	173,235	

Otter Creek Tract 2, 2012\$	Basis	Units	Year-5	Year-4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Totals
Joint Facilities																												
Other	0.060	\$/Unit						4,529	4,529	4,529	4,529	4,529	4,529	4,529	4,529	4,529	4,529	4,529	4,529	5,190	5,362	5,362	5,362	5,362	5,362	5,362	96,242	
Total Non-Controllable Cash Costs								93838	94368	95140	96002	96754	97623	98583	99433	100350	101335	102747	103661	104631	107695	109202	110328	111480	112611	113709	114911	2,064,400
\$/SALES TON								4.69	4.72	4.76	4.80	4.84	4.88	4.93	4.97	5.02	5.07	5.14	5.18	5.23	5.38	5.46	5.52	5.57	5.63	5.69	5.75	5.16
TOTAL CASH COSTS								190031	190562	191333	192195	192947	193816	194776	195626	196544	197528	198941	199854	200825	213664	217719	218845	219997	221128	222227	223429	4,071,987
\$/SALES TON								9.50	9.53	9.57	9.61	9.65	9.69	9.74	9.78	9.83	9.88	9.95	9.99	10.04	10.68	10.89	10.94	11.00	11.06	11.11	11.17	10.18
EBITDA																												
Total EBITDA								26,069	29,037	31,821	34,572	37,491	40,353	43,185	46,187	49,185	52,179	54,809	58,003	61,208	52,611	52,867	56,122	59,422	62,815	66,314	69,783	984,032
\$/SALES TON								1.30	1.45	1.59	1.73	1.87	2.02	2.16	2.31	2.46	2.61	2.74	2.90	3.06	2.63	2.64	2.81	2.97	3.14	3.32	3.49	2.46
DEPRECIATION AND TAXES																												
Depreciation	\$/Unit							19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,113	19,113	19,113	19,113	19,113	19,113	19,113	19,113	19,113	381,728	
Net Income Before Taxes								7,009	9,977	12,761	15,512	18,431	21,293	24,125	27,127	30,125	33,119	35,696	38,890	42,095	33,498	33,754	37,009	40,309	43,702	47,201	50,670	602,304
MT State tax	3.4%							238	339	433	527	626	723	819	921	1,023	1,125	1,212	1,321	1,429	1,137	1,146	1,257	1,369	1,484	1,603	1,721	20,453
Federal Tax (35% or 20% AMT)	18.6%							1,304	1,856	2,373	2,885	3,428	3,960	4,487	5,045	5,603	6,160	6,639	7,233	7,829	6,230	6,278	6,883	7,497	8,128	8,779	9,424	112,025
After Tax Net Income								5,468	7,783	9,954	12,100	14,377	16,610	18,819	21,161	23,499	25,835	27,845	30,336	32,836	26,130	26,330	28,869	31,443	34,090	36,819	39,525	469,827
CAPITAL																												
Working Capital	24,048							24,048																				24,048
Permitting -	5,000																											5,313

Otter Creek Tract 2, 2012\$	Basis	Units	Year-5	Year-4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Totals
Engineering																												
Exploration	3,000			3,188																							3,188	
Drilling																												
Mine	29,000					30,688																					30,688	
Facilities																												
Coal	70,000					74,074																					74,074	
Handling Plant																												
Miscellaneous Equipment and supplies						1,816	1,816	3,629								7,258											14,519	
Dragline - 70 cyd																											0	
Dragline - 110 cyd	109,000	1				116,965										537											117,501	
53 cyd Rock Shovel	12,200	1				13,113																					13,113	
20 cyd Rock Shovel																											0	
314 Ton Rock Trucks - OB	3,628	5				19,465										19,465											38,931	
314 Ton Rock Trucks - Coal	3,628	5				19,465										19,465											38,931	
38 cyd Front-End Coal Loader	6,781	1				7,276										7,276											14,553	
20 cyd Coal Excavators																											0	
290 to 320 Coal Bottom Dump Trucks																											0	
Mobile Equipment	5%					9,094										9,094											18,189	

Otter Creek Tract 2, 2012\$	Basis	Units	Year-5	Year-4	Year -3	Year -2	Year -1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Totals
Reclamation	5,931						6,365										6,365											12,729
Equipment																												
Total Capital (\$000s)				8,501	0	322,369	1,816	3,629	0	0	0	0	0	0	0	69,461	0	0	0	0	0	0	0	0	0	0	405,776	
CASH FLOW and NPV																												
Depreciation (\$000s)								19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,060	19,113	19,113	19,113	19,113	19,113	19,113	19,113	19,113	19,113	19,113	381,728
After Tax Net Income (\$000s)								5,468	7,783	9,954	12,100	14,377	16,610	18,819	21,161	23,499	25,835	27,845	30,336	32,836	26,130	26,330	28,869	31,443	34,090	36,819	39,525	469,827
Less Capital (\$000s)				8,501	0	322,369	1,816	3,629	0	0	0	0	0	0	0	69,461	0	0	0	0	0	0	0	0	0	0	0	405,776
Net Cash Flow (\$000s)				-8,501	0	-322,369	22,712	23,213	29,014	31,160	33,437	35,670	37,878	40,220	42,559	-24,567	46,958	49,449	51,949	45,243	45,443	47,982	50,556	53,203	55,932	58,638	445,778	
\$/SALES TON								1.14	1.16	1.45	1.56	1.67	1.78	1.89	2.01	2.13	-1.23	2.35	2.47	2.60	2.26	2.27	2.40	2.53	2.66	2.80	2.93	1.11
Real, Post-Tax Expected Rate of Return	8.3%																											
Internal Rate of Return (Calculated)	8.3%																											
Net Present Value (Calculated)	-274																											
Capital Charge Rate (Calculated)	15%																											

The primary reason that the Norwest production cost estimate is so much higher than the OEA estimate is that Norwest assumed both more equipment and a higher per-unit cost for that equipment. For mines of about the same size (20 million tons per year), more equipment working at lower efficiencies in the Norwest estimate resulted in higher variable costs (dollars per BCY for dragline and truck and shovel overburden removal) compared to the OEA estimate. These significant capital expenditures estimated at \$1 billion by Norwest would need to be recouped by a higher selling price, which would also mean increased royalty and tax payments, further adding to the higher production cost estimate. Norwest's greater equipment cost is also driven in part by the 50% higher stripping ratio (4.53 BCY per ton versus 3.01) in the Norwest model versus the OEA result. The higher Norwest stripping ratio is also a function of the over 40-year mine life, as opposed to the expected 20-year mine life used in this analysis. OEA's equipment cost estimate reflects recent and applicable data from Arch Coal, as well as more recent equipment cost information. Table 6-7 details some of the key mine characteristics and cost components for comparison.

Table 6-7. Key Items of Comparison, OEA and Norwest Estimates

Key Comparison Item	Units	OEA Estimate	Norwest Estimate
Otter Creek tract(s)	--	2	1 + 2
Raw coal production	million tons per year	21	22.3
Coal sales	million tons per year	20	21.2
Mine life	year	20	40
Overall stripping ratio	BCY/ton	3.01	4.53 ^a
Total units	(BCY + ton)/ton	4.01	5.53
Average hourly wage rate, including benefits	\$/hr	\$55.80	\$44.33
Productivity	tons/worker-hr	31	31
Explosives cost	\$/unit	\$0.33	\$0.37
Dragline(s)	number	1	3
Dragline cost	million \$	\$117	\$449
T/S (overburden + coal) fleet	number	10	20
Total equipment cost, over mine life	million \$	\$406	\$1,073

Notes:

^a The calculated total stripping ratio for Norwest 2009 LMU 5 based on the reported coal production and waste overburden data is 4.53 BCY/ton ((2,880,500 BCY + 891,245 BCY)/833,500 tons), not the listed value of 3.28 BCY/ton. The 20-year stripping ratio for Norwest 2009 LMU 5 is 3.97.

BCY = bank cubic yards, T/S = truck/shovel, LMU = logical mining unit

Similar to Figure 6-8, Figure 6-9 provides a summary of costs broken out by component comparing the OEA estimate with the Norwest estimate. The other noncontrollable costs are higher in the Norwest analysis because of both the higher equipment costs (\$1 billion versus \$400 million) and the higher assumed selling price of \$19.75/ton, versus the \$10.80/ton estimated by OEA for coal with a heat content of 8600 Btu/lb. This higher price also increases the Norwest cost categories for royalties, severance tax, and taxes. The higher

equipment cost increases the Norwest depreciation and return on capital. Thus, the two factors of higher equipment costs and higher sales price have multiplicative effects on the overall production cost estimate. Figure 6-10 shows the overall production costs across all years. To allow for a more useful comparison, the Norwest costs have been generally inflated from 2008 dollars to 2012 dollars (a 6.3% increase).

Figure 6-9. Otter Creek Production Cost for Year 1 at Full Production, OEA and Norwest

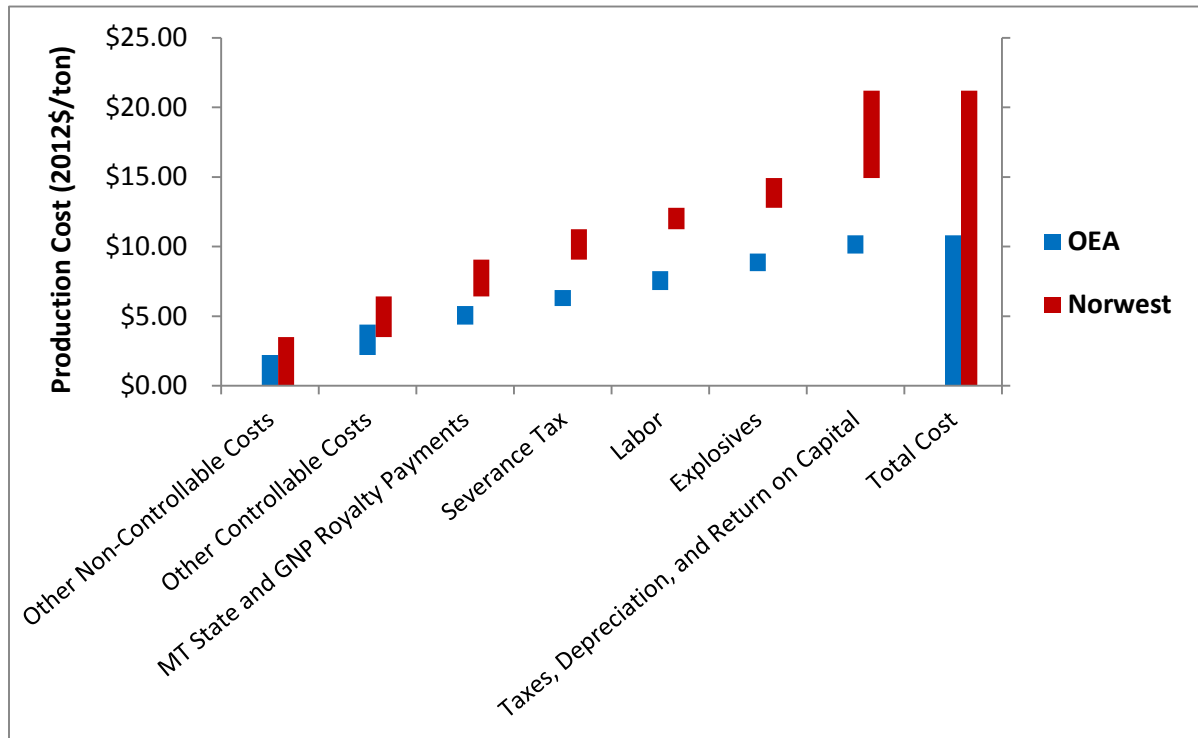
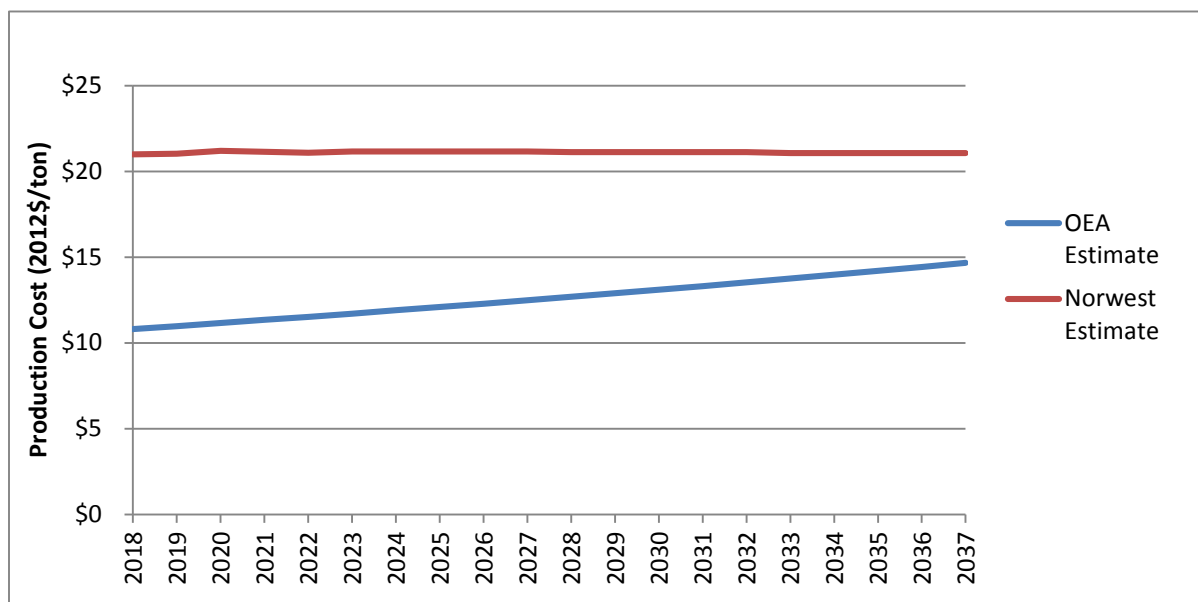


Figure 6-10. Overall Otter Creek Production Costs, OEA and Norwest



6.5.2 Controllable Costs

Table 6-8 summarizes the controllable costs (as defined in Norwest) in OEA's calculations versus the Norwest estimate on a dollars-per-ton, dollars-per-unit, or dollars-per-BCY basis. Labor is split into two comparable units of comparison: dollars per ton and dollars per unit, with the dollars-per-unit costs differing from the dollars-per-ton costs because of the difference in stripping ratios between OEA's estimate (overall 3.01 BCY per ton) versus Norwest (LMU 5 overall 4.53 BCY per ton). The main difference is in overburden removal costs, which stems from the difference in equipment quantity. Other support equipment, other supplies and services, coal handling plant, and reclamation costs on a dollars-per-ton basis have been inflated from Norwest estimates. Overall, OEA's estimate uses many of Norwest's underlying assumptions but uses Arch Coal's more recent estimate of stripping ratios, which is the biggest driver of overall production costs for a mine.

Table 6-8. Controllable Costs, OEA and Norwest Estimates

Controllable Costs Comparison	Units	OEA Estimate (2012\$)	Norwest Estimate (2012\$)
Labor	\$/ton	1.44	1.52
Labor	\$/unit	0.36	0.28
Overburden removal: dragline	\$/BCY	0.10	0.24
Overburden removal: T/S	\$/BCY	0.50	0.75
Explosives	\$/unit	0.33	0.39
Coal loading - haulage	\$/ton	0.53	0.81
Other support equipment	\$/ton	0.45	0.47
Other supplies and services	\$/ton	0.12	0.13
Coal handling plant	\$/ton	0.19	0.20
Reclamation	\$/ton	0.36	0.37

6.5.3 Noncontrollable Costs

Table 6-4 provides a summary of the primary noncontrollable costs. Costs are either identical to Norwest's regarding total dollar amount (lease rental fee, reclamation bonding, insurance, corporate overhead and joint facilities, and other noncontrollable costs), identical from a basis perspective (dollars per ton or percent of revenue amounts are the same, but the tonnage or revenue basis is different between the two estimates), or entirely different, for property taxes only (as detailed in Section 6.4.4.4). OEA used the Norwest income tax estimate, which is approximately half that of the marginal statutory federal and state income tax rate.

6.6 Otter Creek Mine Production Cost Comparison: Boyd 2011

Boyd's cost estimate for mining the Otter Creek reserves is compared with the Norwest and OEA estimates. In addition to Norwest, Boyd provides the only other publicly available, detailed, and recent estimate of Otter Creek Mine production costs.

6.6.1 Overview

Boyd, a worldwide mining and geological consultancy with extensive experience in the Powder River Basin, was retained by Xcel Energy to provide an estimate of available resources, cost of recovery, and forecast of FOB mine prices for Powder River Basin coal over the next 30 years, through 2040. The Powder River Basin resource and cost study has been cited in Public Utilities Commission testimony work in Colorado in 2012 (John T. Boyd Company 2011).

6.6.2 Primary Drivers of Cost

While the Boyd report does not show the inner workings of its surface mine cost model, the report includes a description of the primary cost drivers, shown in Table 6-9, as well as a description of the royalties and taxes that are added to the mining cost. It also includes a mine-by-mine estimate of production, cash costs, and production costs for all existing and proposed Powder River Basin mines through 2040.

Boyd estimates production costs for existing and proposed Powder River Basin mines using Boyd's proprietary Powder River Basin surface mine cost model. The estimated production costs include all direct operating costs, royalties, taxes, overhead, and noncash costs such as depreciation, depletion, and amortization (John T. Boyd Company 2011). Initial, replacement, and sustaining capital investment in the mines is recognized through the addition of a dollars-per-ton depreciation cost. Federal bonus bid expenditures have been included as a dollars-per-ton depletion cost rather than as lump sum payments in the 5 years following award of the federal lease (John T. Boyd Company 2011).

Table 6-9. Primary Cost Drivers in the Boyd Surface Mine Cost Model

Annual coal production (tons per year)
Stripping ratio (prime bank cubic yards of waste per ton of coal produced)
Average coal seam thickness (feet)
Annual disturbance area (acres)
Average topsoil depth (feet)
Percent of overburden removed with draglines
Estimated dragline rehandle (% of dragline overburden excluding cast blast benefit)
Percent of overburden removed with T/S
Percent of overburden cast blasted
Cast blast powder factor (pounds of explosives per BCY of overburden)
Cast blast benefit (% to final placement)
Percent of overburden fragmented with conventional blasting
Conventional blasting powder factor (pounds of explosives per BCY of overburden)
Percent of overburden not blasted
Coal blasting powder factor (pounds of explosive per ton of coal)
Coal truck haul distance (one-way distance in miles)
Coal conveying distance (miles)
Labor force productivity (measured in equivalent mining units defined as BCY of overburden plus tons of coal per employee-hour)
Federal coal production (% of total coal production)
State coal production (% of total coal production)
Private land (Fee coal) coal production (% of total production)
Notes:
BCY = bank cubic yard; T/S = truck and shovel; Btu/lb = British thermal units per pound

6.6.3 Royalties, Taxes, and Insurance Comparison

Boyd does not explicitly mention the allowable royalty and tax deductions and insurance when calculating the gross proceeds tax or the resource indemnity trust tax (though they are mentioned for severance). OEA's estimate of property taxes and insurance are a bit less than what Boyd estimates, though Boyd may not be taking asset value as total asset value, including both heavy equipment and fixed facilities. OEA also simplified and rounded up its calculation of the black lung excise tax and the abandoned mine lands reclamation fee. For sales prices less than \$12.50 per ton, the black lung excise tax would be slightly less than the cap of \$0.55 per ton but for simplicity purposes OEA's analysis assumed \$0.55 per ton. OEA also assumed the higher abandoned mine lands reclamation fee of \$0.35 per ton.

The largest driver of cost differences between the Boyd and OEA estimates is the treatment of private land royalties. OEA conservatively assumed that Great Northern Plains land receives the same percent of realization as that of federal or state land royalty; whereas, Boyd assumed that the percent of realization would be lower for private land than for federal or state land. OEA was unable to find historical private rates for private land, and the percent of realization rates for Great Northern Plains land may not have been negotiated yet. Great Northern Plains land constitutes about 50% of the land in Otter Creek Tract 2, which is

significant from an overall royalties cost perspective. Table 6-10 presents a comparison of royalties, taxes, and insurance.

Table 6-10. Royalties, Taxes, and Insurance, OEA and Boyd Estimates

Royalties, Taxes, and Insurance	OEA Estimate	Boyd Estimate
Montana state royalty	12.5% of realization	12.5% of realization
Private land royalties	12.5% of realization	8.0% of realization
Coal workers black lung excise tax	\$0.55/ton	4.4% of realization up to maximum \$0.55/ton
Abandoned mine lands reclamation fee	\$0.35/ton	\$0.315/ton (2011 and 2012), \$0.28/ton (2013–2021) and \$0.35/ton (2022 and thereafter)
Montana gross proceeds tax	5.0% of realization, less deductions	5.0% of realization
Montana severance taxes	15.0% of realization, less deductions, plus \$0.15/ton	15.0% of realization (less black lung excise tax less abandoned mine lands fee less royalties less gross proceeds tax plus \$0.15/ton)
Montana resource indemnity trust tax	0.4% of realization, less deductions	0.4% of realization
Property taxes	Estimated at 0.65% of total asset value per year	Estimated at 1.0% of asset value per year
Insurance	Estimated at 0.3% of total asset value per year	Estimated at 0.5% of asset value per year

6.6.4 Otter Creek Characteristics

The two primary differences in Otter Creek assumptions between the OEA estimate and the Boyd estimate are annual production and labor productivity (Table 6-11). The OEA estimate is based on Arch Coal’s permit for Otter Creek at 20 million tons per year coal production, concurrent with the 2018 to 2037 analysis period. The Boyd estimate of production is the same as Norwest’s estimate of Otter Creek production from LMU 5 and LMU 6 at 34.9 million tons per year. The OEA labor productivity assumption is based on average 2011 Wyoming surface Powder River Basin mines productivity of 31 tons per hour and an overall stripping ratio of 4 BCY per ton, since there are more surface mines in the Wyoming Powder River Basin region than in Montana, and therefore, an increased number of data points to compare.

Boyd’s labor productivity assumption was taken from Spring Creek’s labor productivity figures. There are only four surface mines in the Montana Powder River Basin region: Decker, Rosebud, Spring Creek, and Absaloka. Decker is likely to close in the near future and, thus, its productivity values may be skewed. Rosebud is dedicated to the minemouth power plant, Colstrip. This leaves only two surface mines in Montana—Spring Creek and Absaloka—for estimating Otter Creek’s labor productivity. This is in comparison to the 12 surface mines in Wyoming, which were used to estimate the Otter Creek labor productivity.

From a risk and diversification perspective, it makes more sense to use 12 data points to estimate labor productivity than two data points.

Table 6-11. Otter Creek Key Characteristics, OEA and Boyd Estimates

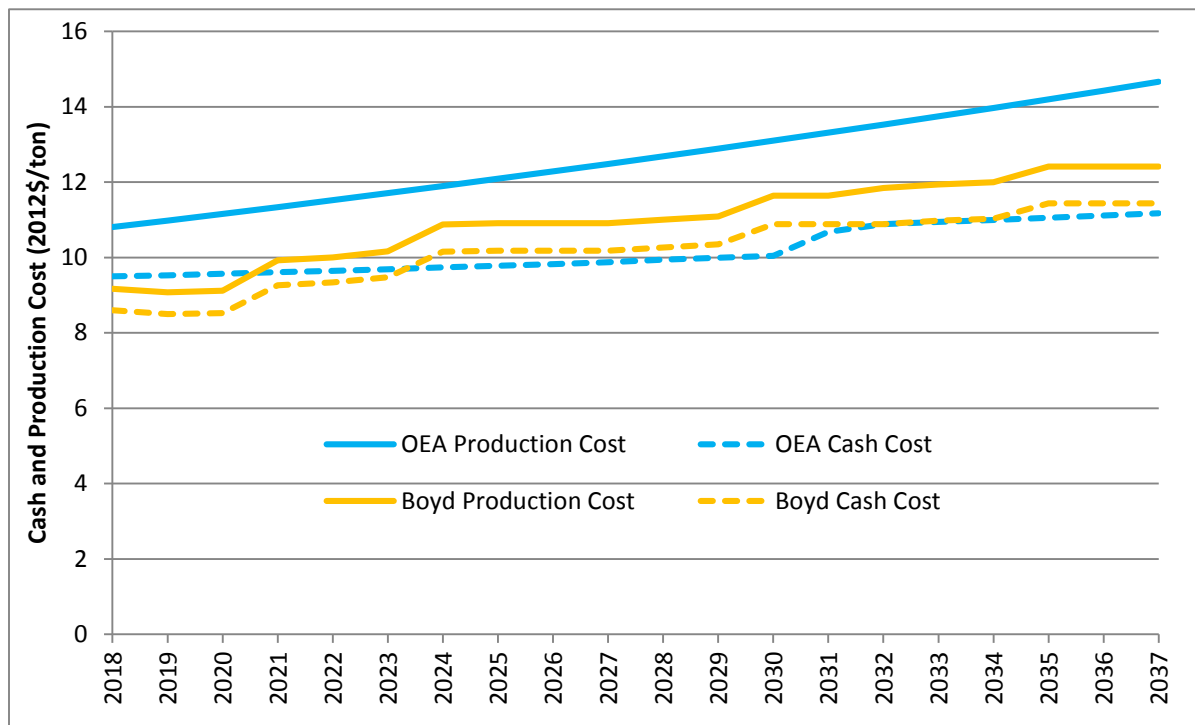
Otter Creek Characteristic	OEA Estimate	Boyd Estimate
Online year	2018	2018
Annual production (million tons per year)	20	34.9
Overall stripping ratio (BCY/ton)	3.01	3.00
Labor productivity (units/hour)	155	120
% Dragline overburden removal	76%	75%
% T/S overburden removal	24%	25%
Seam thickness (feet)	59	57
Coal heat content (Btu/lb)	8,600	8,600
Notes:		
BCY = bank cubic yard; T/S = truck and shovel; Btu/lb = British thermal units per pound		

6.6.5 Cash and Production Costs

Figure 6-11 shows a comparison of OEA and Boyd estimates for Otter Creek Mine cash and production costs. When comparing their estimates in 2012 dollars, OEA cash costs are on average about 0.2% lower than Boyd's estimate; OEA production costs are on average about 15% higher than Boyd's estimate. The primary cash cost drivers for Otter Creek, shown in Table 6-11, are similar between the two estimates, so it makes sense that the cash cost estimates are similar. OEA forecasts an increase in costs around 2031 as the lower stripping ratio sections of land near the western portion of Tract 2 (Sections 11, 14, 23, 26) are depleted. This is merely a function of the aggregated grouping of land into tracts, where differences in stripping ratios are averaged together. The actual sequence of depletion from Tract 2 to Tract 3 would be more continuous.

Production costs, however, varied relatively significantly between the two estimates. OEA production costs include depreciation costs (recovery of capital costs), treatment of federal and state income taxes, and a real rate of return (recovery on capital costs). Boyd explicitly mentions that its cash cost and production cost delta included depreciation, depletion, and amortization. Depreciation includes initial, replacement, and sustaining capital investment and depletion includes federal bonus bid expenditures. The Boyd estimate does not mention treatment of income taxes, nor does it mention an IRR for the greenfield mine. Thus, because Boyd did not consider these items, it is reasonable that the OEA estimate of Otter Creek production costs is higher than the Boyd estimate. The OEA cost estimate is a smooth line because of the implicit 1.6% per year growth in real prices.

Figure 6-11. Cash and Production Costs, OEA and Boyd Estimates



6.7 Production Costs: Other Mines of Interest

6.7.1 Coal Cost Guide

OEA's Poker Jim Creek–O'Dell Creek deposit and Canyon Creek deposit production cost estimates use the current Otter Creek Mine year-by-year production cost estimate from the discounted cash flow model described in Section 6.4, *Otter Creek Mine Production Costs*, as a starting point. The Poker Jim Creek–O'Dell Creek deposit and Canyon Creek deposit differ from the Otter Creek Mine in two readily identifiable ways: annual coal production and stripping ratio. To adjust the estimated cost of production for these differences, OEA used cost versus production level and cost versus stripping ratio relationships developed from the various surface mine costs provided in InfoMine USA's 2010 *Coal Cost Guide* (InfoMine USA 2010). Otter Creek production costs at a higher level of production (34 million tons per year) were also estimated using the cost relationships developed from the Coal Cost Guide. The guide estimates cannot be used directly to estimate the costs for these mines because the information in the guide is not sufficiently detailed to estimate costs accurately. The following excerpt from the Coal Cost Guide describes the mine models contained therein (InfoMine USA 2010).

In the following, we present a series of cost models for surface coal mines, underground coal mines, raw coal receiving and storage, coal preparation plants, and clean coal storing, drying, loading and refuse disposal from which evaluators can use to make preliminary, order of magnitude estimates for

projects for which there is limited deposit information. These models are based upon theoretical engineering parameters and do not represent any specific mine or plant.

OEA did not have access to a mine-specific list of equipment for these mines, and the deposits also lack a detailed section-by-section estimate of in-place coal tons and BCY of overburden, similar to what the Norwest 2006 study estimated for Otter Creek Tracts 1, 2, and 3. Since there is limited deposit information for Poker Jim Creek–O’Dell Creek deposit and Canyon Creek deposit, OEA used the scaling relationships inherent in the Coal Cost Guide models to scale the detailed production cost estimate of Otter Creek Mine to estimate production costs for the other mines.

The Coal Cost Guide presents 18 surface mine cost models with varying levels of production and stripping ratios. Surface mine models employ dragline and T/S operations, projected at five levels of daily saleable coal production: 2,000, 8,000, 24,000, 72,000, and 216,000 tons per day. Assuming a similar 7,560 hours per year of mine operation as the number of operational hours in the Otter Creek discounted cash flow model, the production levels can be converted to million tons of yearly production. At each of these levels, model estimates are made for three stripping ratios: 5.0 cubic yards overburden per ton of coal, 10.0 cubic yards overburden per ton of coal, and 20.0 cubic yards overburden per ton of coal. Three additional cost model estimates at a production of 72,000 tons per day and a stripping ratio of 2.0 BCY per ton, production of 216,000 tons per day and a stripping ratio of 2.0 BCY per ton, and production of 216,000 tons per day and a stripping ratio of 1.0 BCY per ton are included. These data are presented in Table 6-12, where the ‘x’s refer to a Coal Cost Guide cost estimate of a mine at the specified production level and stripping ratio combination.

Table 6-12. Coal Cost Guide Combination of Production and Stripping Ratio Cost Estimates

Daily Production (tons/ day)	Stripping Ratio (cubic yards/ton)				
	1	2	5	10	20
2,000			X	X	X
8,000			X	X	X
24,000			X	X	X
72,000		X	X	X	X
216,000	X	X	X	X	X

The cost models include all labor, material, supply, and equipment operating expenses, including supervision, administration, and onsite project management costs. Project area-specific costs (taxes, loadout, processing, insurance) are not included (InfoMine USA 2010). Figures 6-12 and 6-13 show a graphical summary of production cost estimates by annual production and production cost estimates by stripping ratio. These estimates aggregate the data in the Coal Cost Guide and apply a best-fit trendline to allow for interpolation. The figures exclude the 0.63 million tons per year or 2,000 tons per day production level estimates, because they are insignificant relative to production levels for the assumed Tongue River mines.

Figure 6-12. Coal Cost Guide New Mine Cost versus Production by Stripping Ratio Relationship

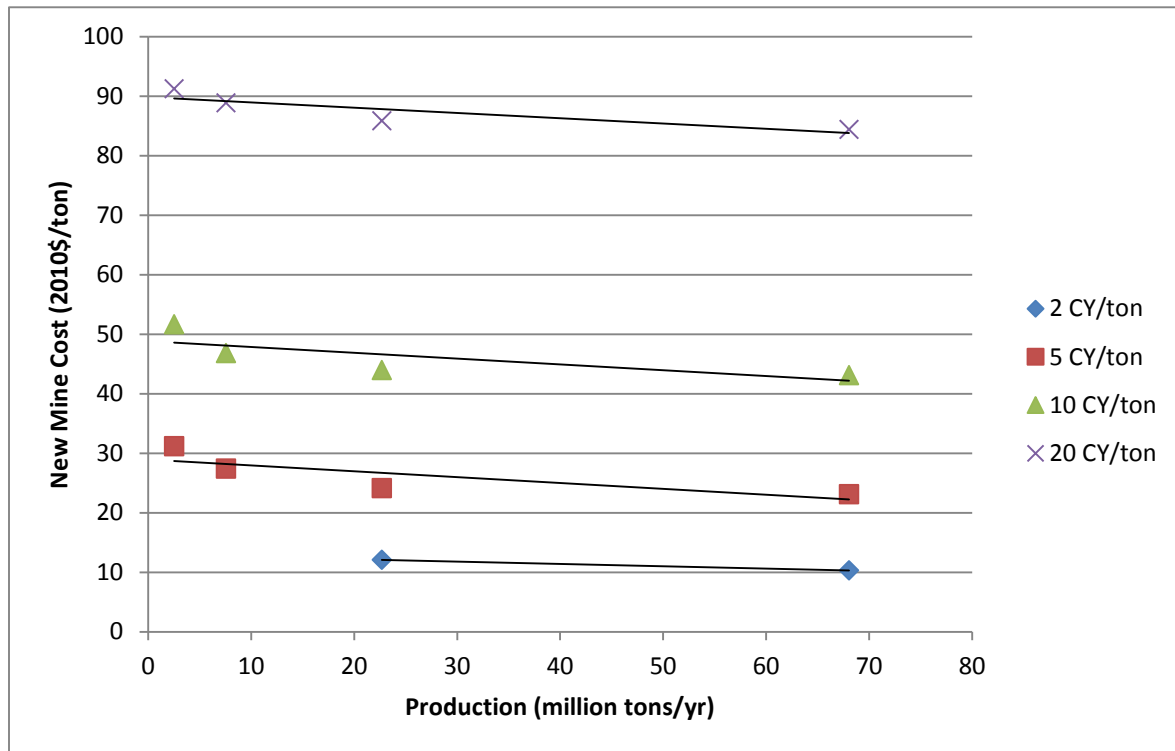
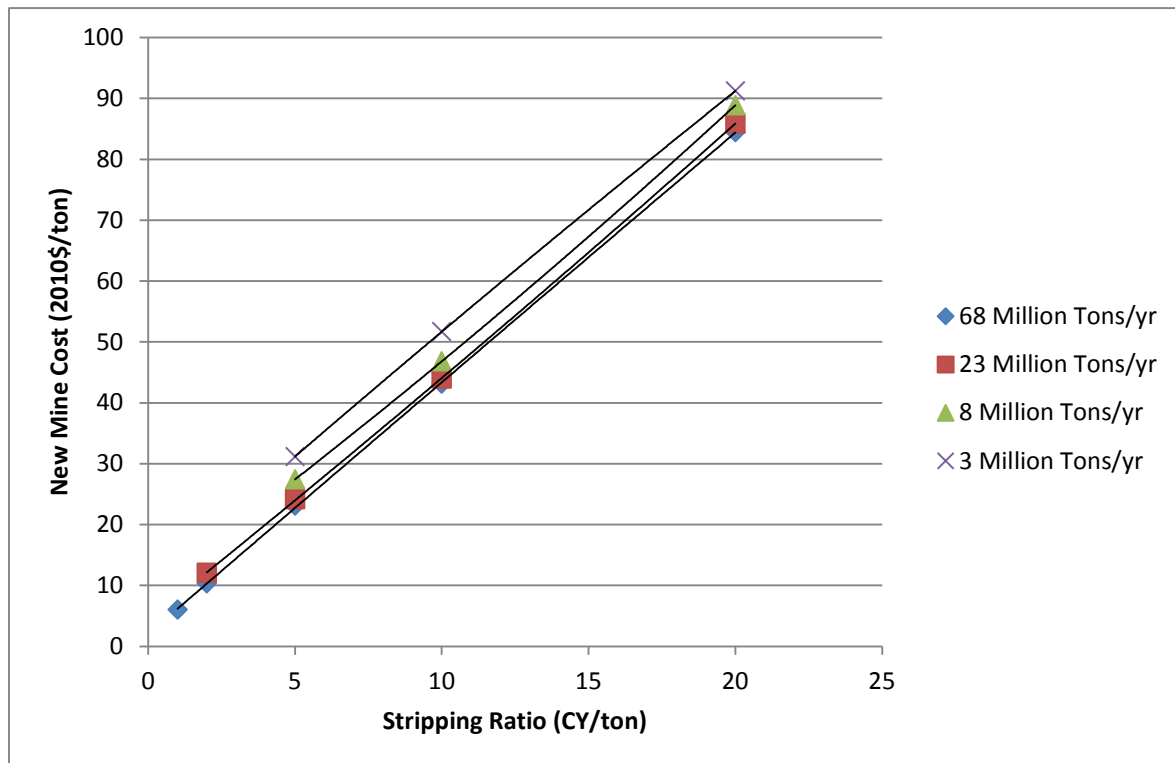


Figure 6-13. Coal Cost Guide New Mine Cost versus Stripping Ratio by Production Relationship



Operating costs in the Coal Cost Guide are categorized by supplies, labor, equipment operation, administration, and miscellaneous. Capital costs in the form of *equipment purchase* and *other* (likely fixed facilities) are estimated for each mine size and stripping ratio combination. To account for depreciation, treat income taxes, and include a return on the capital expenditure investment for consistency purposes, OEA applied a capital charge rate to the capital costs. The rate is expressed as the ratio of the yearly average capital recovery payments to the total capital cost, and may be estimated by averaging yearly gross margin (earnings) before interest, taxes, depreciation, and amortization (EBITDA) and dividing by the initial capital expenditure.

An average of yearly EBITDA per initial capital expenditures over the 20-year mine life assumed in OEA's Otter Creek discounted cash flow model yielded 15% as a capital charge rate. This rate was applied to the total capital costs in the Coal Cost Guide, then converted on a dollars-per-ton basis and added to the operating costs.⁹ Additional operating cost and capital cost data cannot be presented here as the Coal Cost Guide is a subscription cost data service with fees charged on a per-user basis.

Despite the lack of *ad valorem* taxes in the Coal Cost Guide, the primary purpose for determining Coal Cost Guide estimates is not for the absolute price estimate itself, but rather to provide a relative basis for comparison across various mine sizes and stripping ratios. This is because the other potential coal mines (i.e., Poker Jim Creek-O'Dell Creek and Canyon Creek) lack similarly detailed information on yearly stripping ratios, equipment lists, and other items, compared to what OEA used for Otter Creek.

OEA estimated production levels for all mines of interest, in addition to the Otter Creek Mine at a higher production level. The production levels at the other mines range from 12 to 34 million tons per year. The regressions in Figure 6-12 show a good linear fit over the production range of 8 to 70 million tons per year. When the production level drops below 8 million tons per year, the slope of the relationship between costs versus mine size changes. The relationships between mine cost and stripping ratio shown in Figure 6-13 are also linear. Thus, the linear relationships between production costs and production volume are reasonable over the range of production levels in the Tongue River area. Taken together, the two figures show that both production level and especially stripping ratio drive production costs.

Table 6-13 summarizes the key mine characteristics taken from Matson and Blumer (1973) and Norwest (2006). The stripping ratios and production levels for the mines obtained from these sources were substituted into the Coal Cost Guide regressions to arrive at a Coal Cost Guide production cost estimate for each mine. Production costs for the Otter Creek Mine at a production level of 20 million tons per year were also estimated using this method. Then all of the Coal Cost Guide estimates were normalized by dividing by the Otter Creek production cost at a production level of 20 million tons per year. The final estimated production costs

⁹ Additional operating cost and capital cost data cannot be presented since the Coal Cost Guide is a subscription cost data service with fees charged on a per-user basis.

for each mine were then determined by multiplying the mine-specific Coal Cost Guide ratios by the Otter Creek (at 20 million tons per year) discounted cash flow production cost estimates as described in Section 6.4, *Otter Creek Mine Production Costs*. The rising production costs over time are due to increased stripping ratios; the difference in costs between the mines is due to both differences in mine-specific stripping ratios, as well as differences in anticipated production levels. These final cost estimates represent the costs that were used in the modeling (Figure 6-14).

Table 6-13. Coal Cost Guide: Key Production and Stripping Ratio Characteristics

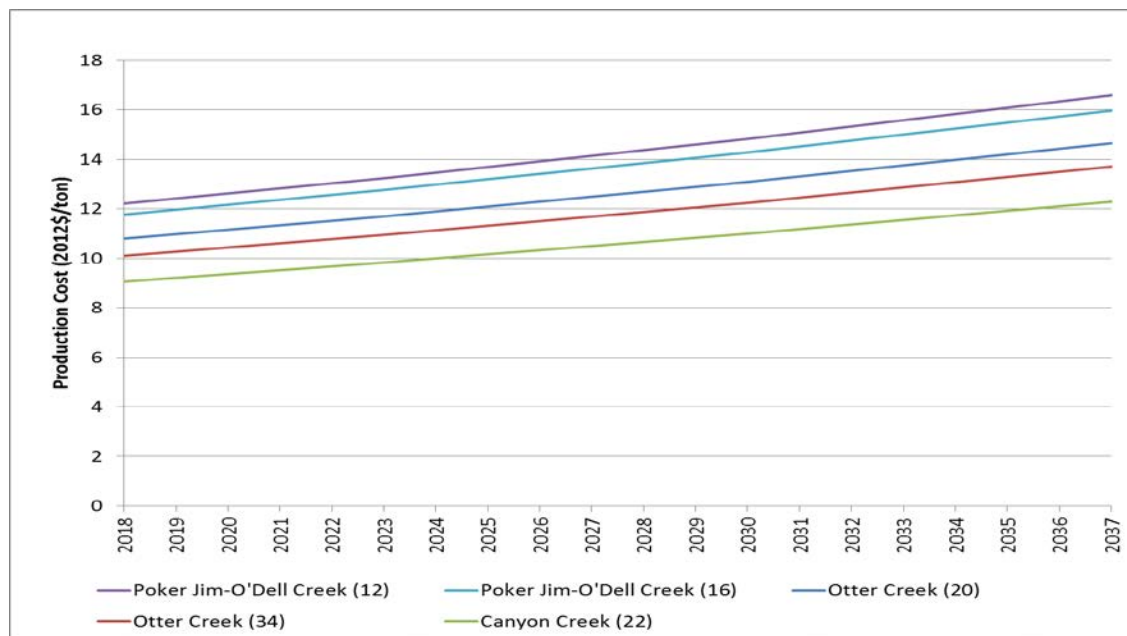
Mine of Interest	Production Level	Production (million tons per year)	Stripping Ratio (BCY/ton)	Heat Content (Btu/lb)
Poker Jim Creek–O’Dell Creek	Medium	12	3.20	8,758
Poker Jim Creek–O’Dell Creek	High	16	3.20	8,758
Canyon Creek	High	22	2.46	9,100
Otter Creek	Low/Medium	20	3.01	8,600
Otter Creek	High	34 ^a	3.01	8,600

Notes:

^a The overall stripping ratio for Otter Creek at 34 million tons per year is assumed to be the same as the overall stripping ratio at 20 million tons per year. Norwest (2006) shows Tracts 1 and 3 as having overall stripping ratio estimates at 3.0 and 2.9 BCY/ton. Tract 2’s overall stripping ratio is also estimated at 3.0 BCY/ton. If the overall stripping ratio for a larger Otter Creek Mine were indeed higher, this would place upward pressure on the production cost estimate.

BCY = bank cubic yard, Btu/lb = British thermal units per pound

Figure 6-14. Coal Cost Guide-Scaled Production Cost Estimates for all Mines of Interest



Note: The values in parentheses are the production level in million tons at each mine.

6.8 Tongue River Railroad Capital Costs

The capital costs for the northern alternatives are estimated to range from \$403.3 to \$908.7 million, as provided in the August 29, 2014 response from the Applicant to questions from OEA contained in the June 16, 2014 Sixth Information Request. Prior to the cost estimates submitted on August 29, 2014, the range of costs was estimated to be between \$416 and \$882 million. The northern alternatives include the following alternatives: Colstrip, Tongue River, Tongue River Road, and Moon Creek; each of those four alternatives has a “variant”, in the form of the Eastern Variation, comprising eight additional alternatives. Thus, the \$403.3 million figure represents the lowest estimated Tongue River Railroad capital cost for the northern alternatives and the \$908.7 represents the highest estimated Tongue River Railroad capital cost for the northern alternatives.

The capital costs of the proposed rail line for the two southern alternatives are estimated to be \$730.0 and \$762.2 million, as provided in the August 29, 2014 response from the Applicant to questions from OEA contained in the June 16, 2014 Sixth Information Request. Prior to the cost estimates submitted on August 29, 2014, OEA estimated the costs to be \$698 and \$832 million.

OEA annualized total capital costs using a capital charge rate. This was spread over the yearly production of maximum potentially induced coal production at each of the three production levels, and then converted to an adder in dollars per million Btu (MMBtu) for the rail costs for Tongue River Railroad movements (Table 6-14) using a weighted average heat rate. The capital charge rate calculation is described in Section 6.9, *Railroad Cost of Capital*.

OEA chose to use the lowest estimated northern and southern alternative cost as representative of all northern and southern alternatives. This provides a more conservative view of the amount of Tongue River coal that would be mined because it tends to overstate the potential coal production. A lower cost of the Tongue River Railroad construction tends to overstate the coal production because a portion of the cost is included in the selling price of the coal, and the lower the cost adder the more economical the Tongue River coal is compared to other coals.

The modeling results that follow in Chapters 8 through 10 assume a construction cost of \$416 million as representative for the northern alternatives and \$698 million as representative for the southern alternatives. For the northern alternatives, \$416 million is not the lowest cost; however, the difference between the northern alternatives’ cost estimate used in the analysis of \$416 million and the actual lowest-cost estimate of \$403 million is small and would have a minimal impact on the results. The only scenario that might change is scenario 9, which does not have full production of Tongue River coal in each year.

Table 6-14. Annualizing Tongue River Railroad Costs as a Transportation Adder

	Northern–Lowest Cost			Northern–Highest Cost		
	Production Level			Production Level		
	Low	Med	High	Low	Med	High
Total railroad cost (million \$)	\$416.2	\$416.2	\$416.2	\$882.0	\$882.0	\$882.0
Real levelized capital charge rate (%) ^a	12.3%	12.3%	12.3%	12.3%	12.3%	12.3%
Annualized railroad cost (million \$/year)	\$51.2	\$51.2	\$51.2	\$108.6	\$108.6	\$108.6
Otter Creek production (million tons)	20	20	34	20	20	34
Poker Jim Creek–O'Dell Creek production (million tons)	0	12	16	0	12	16
Canyon Creek production (million tons)	0	0	0	0	0	0
Otter Creek heat content (MMBtu/ton)	17.2	17.2	17.2	17.2	17.2	17.2
Poker Jim Creek–O'Dell Creek heat content (MMBtu/ton)	17.5	17.5	17.5	17.5	17.5	17.5
Canyon Creek heat content (MMBtu/ton)	18.2	18.2	18.2	18.2	18.2	18.2
Total max production (million tons)	20	32	50	20	32	50
Yearly adder (\$/ton)	\$2.56	\$1.60	\$1.02	\$5.43	\$3.39	\$2.17
Weighted heat content (MMBtu/ton)	17.2	17.3	17.3	17.2	17.3	17.3
Yearly Transportation Adder (\$/MMBtu)	\$0.15	\$0.09	\$0.06	\$0.32	\$0.20	\$0.13
	Southern–Lowest Cost			Southern–Highest Cost		
	Low	Med	High	Low	Med	High
Total railroad cost (million \$)	\$698.0	\$698.0	\$698.0	\$832.0	\$832.0	\$832.0
Real levelized capital charge rate (%) ^a	12.3%	12.3%	12.3%	12.3%	12.3%	12.3%
Annualized railroad cost (million \$/year)	\$85.9	\$85.9	\$85.9	\$102.4	\$102.4	\$102.4
Otter Creek production (million tons)	20	20	34	20	20	34
Poker Jim Creek–O'Dell Creek production (million tons)	0	12	16	0	12	16
Canyon Creek production (million tons)	0	0	22	0	0	22
Otter Creek heat content (MMBtu/ton)	17.2	17.2	17.2	17.2	17.2	17.2
Poker Jim Creek–O'Dell Creek heat content (MMBtu/ton)	17.5	17.5	17.5	17.5	17.5	17.5
Canyon Creek heat content (MMBtu/ton)	18.2	18.2	18.2	18.2	18.2	18.2
Total max production (million tons)	20	32	72	20	32	72
Yearly adder (\$/ton)	\$4.30	\$2.69	\$1.19	\$5.12	\$3.20	\$1.42
Weighted heat content (MMBtu/ton)	17.2	17.3	17.6	17.2	17.3	17.6
Yearly Transportation Adder (\$/MMBtu)	\$0.25	\$0.16	\$0.07	\$0.30	\$0.18	\$0.08

Notes:

^a Capital charge rate determined using STB's 2009-2011 average real post-tax weighted average cost of capital for the rail industry of 8.3% and a 30-year book life.

MMBtu = million British thermal units

For the southern alternatives, OEA used a value of \$698 million as the cost estimate, which is lower than the actual lowest-cost estimate of \$730.0 million. Thus, the cost estimate used in the analysis provides a more conservative result by potentially over-estimating the amount of coal production. The reasonableness of using the higher construction cost for the northern alternatives is supported by the finding of little to no decrease in overall potentially induced Tongue River coal production with the highest Tongue River Railroad capital costs, which is presented in Section 7.3.1, *Alternatives*.

6.9 Railroad Cost of Capital

OEA used public Surface Transportation Board cost of capital figures to estimate a capital charge rate to annualize the total Tongue River Railroad costs. OEA converted an average of 2009 to 2011 nominal weighted average cost of capital (WACC) was converted to real dollars assuming a 2.5% inflation rate. The 8.3% real WACC, in conjunction with a 30-year book life for the Tongue River Railroad asset, a 20-year private debt life, and a 30-year depreciation schedule implies a capital charge rate of 12.3%, which OEA used to annualize the total Tongue River Railroad cost. Table 6-15 shows the 2011 debt share, equity share, debt rate, and equity rate figures for illustrative purposes.

Table 6-15. Surface Transit Board Railroad Cost of Capital

2011 Surface Transportation Board Cost of Capital Figures	Percent (%)
2011 post-tax WACC (nominal)	11.57
2010 post-tax WACC (nominal)	11.03
2009 post-tax WACC (nominal)	10.43
2009-2011 average WACC (nominal)	11.01
2011 Surface Transportation Board debt share	20.83
2011 Surface Transportation Board equity share	79.17
2011 Surface Transportation Board debt rate (post-tax, nominal)	3.97
2011 Surface Transportation Board equity rate (nominal)	13.57
Assumed inflation	2.50
2009-2011 post-tax average WACC (real)	8.30
Capital Charge Rate	12.31
Notes:	
Source: Progressive Railroading 2012	
WACC = weighted average cost of capital	

6.10 Coal Mining Cost of Capital

OEA used the Capital Asset Pricing Model to estimate the cost of capital for coal companies, oil and gas companies, and regulated and unregulated electric companies. Coal companies have been found to have the highest relative cost of capital, at about a 7.7% real WACC. OEA nevertheless assumed a slightly more conservative and higher discount rate of 8.3%,

similar to the real 2009 to 2011 average discount rate that the Surface Transportation Board estimates for the railroad industry. The summary comparison is presented in Table 6-16 and relevant coal companies analyzed are presented in Table 6-17.

Table 6-16. Weighted Average Cost of Capital and Capital Charge Rate Comparison by Industry

	Regulated Electric Companies	Merchant Electric Companies	Oil and Gas Companies	Coal Companies
Debt-Equity Ratio^a				
Target Equity Ratio	45%	45%	60%	74%
Target Debt Ratio	55%	55%	40%	26%
Equity Rates				
Nominal after-tax equity rate ^b	8.8%	16.1%	13.5%	12.2%
Nominal pre-tax equity rate	14.4%	26.5%	22.1%	20.0%
Real after-tax equity rate	6.4%	13.5%	11.0%	9.7%
Real pre-tax equity rate	11.9%	23.7%	19.4%	17.3%
Debt Rates				
Nominal after-tax debt rate	3.5%	4.6%	3.4%	4.3%
Nominal pre-tax debt rate ^c	5.7%	7.6%	5.6%	7.1%
Real after-tax debt rate	1.2%	2.3%	1.1%	2.0%
Real pre-tax debt rate	3.4%	5.2%	3.3%	4.7%
Taxes, Inflation, Book and Debt Life				
Income tax rate ^d	39.1%	39.1%	39.1%	39.1%
Inflation ^e	2.3%	2.3%	2.3%	2.3%
Property tax and insurance	0.9%	0.9%	0.9%	0.9%
Book life (years)	30	30	30	30
Debt life (years)	20	20	20	20
Output				
Nominal after-tax weighted average cost of capital (%)	5.9%	9.8%	9.5%	10.1%
Nominal pre-tax WACC	9.6%	16.1%	15.5%	16.7%
Real after-tax weighted average cost of capital	3.5%	7.4%	7.0%	7.7%
Real pre-tax weighted average cost of capital	7.2%	13.5%	13.0%	14.1%
Real Capital Charge Rate	8.5%	13.8%	12.9%	13.2%

Notes:

- ^a The 2013 debt-to-equity ratio of 1.01 for coal companies has increased significantly from its 5-year average of 0.35. OEA assumes that the recent increase in the share of debt of these companies will decline and their debt-to-equity ratio will return to their historical 5-year average levels. Thus, OEA assume a 0.35 target debt-to-equity ratio when calculating cost of equity with Capital Asset Pricing Model.
- ^b The nominal after-tax equity rate was calculated with Capital Asset Pricing Model based on historical data from 2008–2012. During that time, the 20-year Risk Free Rate based on U.S. Treasuries averaged 3.73%. The expected equity risk premium or the difference between S&P 500 total returns and long-term government bond income returns was estimated to be 6.62% and was based on 1926–2011 equity risk premium average as reported in Ibbotson Associates' 2012 Yearbook. Company-specific size premiums were incorporated based Ibbotson 2011 Yearbook size premium estimates.
- ^c The nominal pre-tax debt rate is based on the historical 5-year average of coupon rates on outstanding long-term debt.
- ^d The income tax rate assumption represents a combination of federal corporate income tax rate of 32.8% and an average of state corporate income tax rates of 6.4%.
- ^e The inflation rate of 2.27% is based on a 10 year (2002–2012) average annual growth of GDP Deflator Index as reported by the U.S. Bureau of Economic Analysis.

Table 6-17. Coal Companies for Capital Asset Pricing Model Analysis

Company	Bloomberg Ticker
Alliance Resource Partners	ARLP Equity
Alpha Natural Resources	ANR Equity
Arch Coal, Inc.	ACI Equity
Cloud Peak Energy, Inc.	CLD Equity
Consol Energy, Inc.	CNX Equity
James River Coal Company	JRCC Equity
Peabody Energy Corp	BTU Equity
Walter Energy	WLT Equity

7.1 Introduction

This chapter describes the rail and coal production scenarios used in OEA's analysis. OEA analyzed 21 scenarios for the proposed rail line alternatives. OEA based these scenarios on three primary variables (route alternative, production level, and terminal capacity growth) plus two additional sensitivities: natural gas prices and national carbon dioxide (CO₂) emission regulations.

OEA compared the scenarios for the proposed rail line alternatives with six scenarios for the No-Action Alternative in which the proposed Tongue River Railroad would not be constructed and no Tongue River coal would be produced. This comparison is needed for two reasons, as follows.

First, the comparison assesses the incremental impact of the Tongue River Railroad. As noted in Chapter 2, *Historical Powder River Basin Production and Markets*, there are already large amounts of Powder River Basin rail traffic.

Second, the comparison assesses whether the Tongue River Railroad is necessary to support the feasibility of exporting coal through the proposed Pacific Northwest terminals. In other words, the comparison assesses whether there would still be coal exports to the Pacific Basin if the proposed terminals are constructed but the Tongue River Railroad is not.

OEA also examined sensitivity cases related to Tongue River coal production costs and Pacific Basin delivered coal prices. Chapter 8, *Coal Production and Transportation Modeling Results*, provides the model results based on these scenarios.

This chapter includes a description of the variables OEA considered in developing the scenarios, an overall description of the scenarios, and how OEA combined the variables. The chapter also provides an overview of the scenarios using the CO₂ control price and natural gas price sensitivities, and discusses how production costs could affect the economic viability of Tongue River coal production. Lastly, the chapter describes the potential effect of decreasing international coal production costs to achieve lower delivered coal costs.

7.2 Variables

7.2.1 Primary Variables

OEA developed the scenarios used for its analysis by combining three primary variables: production, terminal capacity growth, and route alternatives.

- **Production.** This variable addresses potential level of Tongue River coal production. For the two sets of route alternatives, northern and southern, OEA analyzed three variables: low, medium, and high.
- **Terminal capacity growth.** OEA analyzed three variables: zero, medium, and high.
- **Route alternatives.** OEA analyzed two sets of route alternatives: northern and southern.

7.2.2 Sensitivities

OEA also analyzed two sensitivities to alternative economic and regulatory conditions: CO₂ price and natural gas prices.

- **CO₂ price.** OEA assumed that there would be no national CO₂ emissions price in the scenarios, but also analyzed a case that included a national CO₂ price as a sensitivity case.
- **Natural gas prices.** OEA analyzed two natural gas price cases where low gas prices were paired with zero export terminal growth and high export terminal growth.¹

7.2.3 No-Action Alternative

OEA analyzed three scenarios under the No-Action Alternative, each varying the growth levels for terminal capacity. OEA also analyzed three additional No-Action Alternatives for the CO₂ and natural gas price sensitivities, for a total of six scenarios under the No-Action Alternative.

7.2.4 Other Variables

OEA analyzed uncertainty in two other parameters: Tongue River coal productions costs and Pacific Basin delivered coal prices.

- **Tongue River coal production costs.** OEA analyzed several cases to assess the impacts of higher production costs for Tongue River coal. OEA estimated the cost at which this coal might not be economically viable.
- **Pacific Basin delivered coal prices.** Although coal prices are expected to increase in the Pacific Basin, OEA assessed the effects of lower delivered coal prices on the economic viability of Tongue River coal.

7.3 Scenarios

By combining the variables described above, OEA modeled 27 different scenarios to explore the effects of these variables and, to a more limited extent, CO₂ controls and natural gas

¹ The terms *zero*, *medium*, and *high growth* are abbreviations for *zero*, *medium*, and *high terminal capacity growth*.

prices on Tongue River coal production and distribution (Table 7-1). OEA created the 27 scenarios—consisting of 21 scenarios for the proposed rail line and six scenarios for the No-Action Alternative—by combining the variables as follows.

- Scenarios that vary three production levels, three growth rates for terminal capacity, and two sets of route alternatives (**18** scenarios).
- Scenarios that vary two natural gas prices and one CO₂ price sensitivity, at a fixed production level (three additional scenarios for a total of **21** scenarios, referred to as the *primary sensitivity scenarios*).
- Scenarios under the No-Action Alternative varying three terminal capacity growth rates (three additional scenarios for a total of **24** scenarios).
- Scenarios under the No-Action Alternative that vary two natural gas prices and one CO₂ price sensitivity, assuming no production (three additional scenarios for a total of **27** scenarios).

Table 7-1. Scenarios Modeled^a

Alternatives	Coal Production	Terminal Capacity Growth			Low Natural Gas Price	Low Natural Gas Price	CO ₂ Policy
		Zero Terminal Capacity Growth	Medium	High Terminal Capacity Growth	Zero Terminal Capacity Growth	High Terminal Capacity Growth	High Terminal Capacity Growth
No-Action Alternative	N/A	X	X	X	X	X	X
Northern	Low/Applicant	X	X	X	X	X	X
	Medium	X	X	X			
	High	X	X	X			
Southern	Low/Applicant	X	X	X			
	Medium	X	X	X			
	High	X	X	X			

Notes:

^a The 21 primary sensitivity scenarios are based on the primary variables of route alternative, production level, and terminal capacity growth plus two scenarios based on natural gas prices and CO₂ constraints. The six No-Action Alternative scenarios are based on terminal capacity growth.

N/A = not applicable; CO₂ = carbon dioxide

To determine the effect of a national CO₂ program and lower natural gas prices on Tongue River coal production, OEA ran two sensitivities using the northern alternatives and high growth.² OEA ran a third sensitivity with lower natural gas prices and zero growth, also using the northern alternatives. OEA only modeled the northern alternatives because it knew that if the northern alternatives were economical with a CO₂ program, the southern alternatives would also be economical because of the larger volume of coal production under

² The terms *zero*, *medium*, and *high growth* are abbreviations for *zero*, *medium*, and *high terminal capacity growth*.

those alternatives. All three sensitivities were run assuming the permitted Otter Creek Mine produces 20 million tons per year (i.e., northern alternatives, low production). The analysis included a no-action case for each of the three sensitivities so that the only change between the sensitivity and the no-action case was the addition of the Tongue River Railroad. Thus, there are three sensitivities and three more no-action cases, for a total of six sensitivity scenarios. In addition to these 27 scenarios, the sensitivity of Tongue River coal distribution was tested as Tongue River coal production costs increased. The test was based on two scenarios: the northern alternatives, low production, zero growth (scenario 3) and the northern alternatives, high production, high growth (scenario 11). OEA modeled these scenarios with seven levels of increased production costs, yielding 14 additional scenarios for the production cost sensitivity only (Section 7.6, *Production Costs*).

Lastly, the northern alternatives, high production, high growth case (scenario 11) tested the sensitivity of Tongue River coal distribution as international coal production costs decreased. This scenario was modeled using four levels of decreased production costs (Section 7.6, *Production Costs*).

Table 7-2 presents each of the 27 primary scenarios. Each scenario is numbered and characterized by the alternative, the production level, the growth level, and sensitivity to either natural gas or CO₂, if relevant. Each scenario has an assigned chart label.

Table 7-2. Description of Scenarios

Scenario	Alternative	Coal Production	Terminal Capacity Growth	Natural Gas?	CO ₂ Price?	Chart Label
1	No-Action Alternative	N/A	Zero			No TRR, Zero growth
2	No-Action Alternative	N/A	High			No TRR, High growth
3	Northern	Low	Zero			N, Low, Zero
4	Northern	Low	Medium			N, Low, Med
5	Northern	Low	High			N, Low, High
6	Northern	Medium	Zero			N, Medium, Zero
7	Northern	Medium	Medium			N, Medium, Medium
8	Northern	Medium	High			N, Medium, High
9	Northern	High	Zero			N, High, Zero
10	Northern	High	Medium			N, High, Medium
11	Northern	High	High			N, High, High
12	Southern	Low	Zero			S, Low, Zero
13	Southern	Low	Medium			S, Low, Med
14	Southern	Low	High			S, Low, High
15	Southern	Medium	Zero			S, Medium, Zero
16	Southern	Medium	Medium			S, Medium, Med
17	Southern	Medium	High			S, Medium, High
18	Southern	High	Zero			S, High, Zero
19	Southern	High	Medium			S, High, Med
20	Southern	High	High			S, High, High
21	Northern	Low	Zero	Low Gas		N, Low, Zero, Low Gas
22	Northern	Low	High	Low Gas		N, Low, High, Low Gas
23	Northern	Low	High		Yes	N, Low, High, Yes CO ₂
24	No-Action Alternative	N/A	High		Yes	No TRR, High, Yes CO ₂
25	No-Action Alternative	N/A	Medium			No TRR, Medium Growth
26	No-Action Alternative	N/A	Zero	Low Gas		No TRR, Zero, Low Gas
27	No-Action Alternative	N/A	High	Low Gas		No TRR, High, Low Gas
Notes: N/A = not applicable; TRR = Tongue River Railroad						

7.3.1 Alternatives

OEA identified 10 alternatives that could meet the purpose and need for the proposed rail line and determined each to be reasonable, i.e., economically and technically reasonable and feasible for purposes of this analysis. These alternatives are described in Chapter 2, *Proposed Action and Alternatives*, of the Draft Environmental Impact Statement (EIS). The northern alternatives consist of a set of four primary routes (Tongue River, Colstrip, Tongue River Road, and Moon Creek) that each have an additional variation (the Eastern Variation).

The northern alternatives costs would range from \$403.3 million to \$908.7 million based on the August 29, 2014 Applicant response to the Sixth Information Request. The \$403.3 million figure represents the lowest estimated Tongue River Railroad capital cost for the northern alternatives, and the \$908.7 represents the highest estimated Tongue River Railroad capital cost for the northern alternatives. Prior cost estimates ranged from \$416 to \$882 million, OEA used these values because the difference between the cost estimate of \$416 million used in the analysis and the new estimate of \$403.3 million is small and is not expected to have an impact on the results.

The Colstrip Alternative would have the lowest cost at \$403.3 million, and the Tongue River Road East Alternative (Tongue River Road plus the Ashland East plus the Terminus 1 Variation; see Chapter 2, *Proposed Action and Alternatives*, of this Draft EIS) would have the highest cost at \$908.7 million. OEA found that there would be only small differences in the amount of Tongue River coal that would be transported using this range of costs. Specifically, a maximum Tongue River Railroad East Alternative cost compared to the minimum cost for the northern alternatives would result in decreased yearly transported coal production ranging from 0% (scenarios 3, 4, 5, 8, and 11) to 6.3% (scenario 10). The relatively small range of the impact, as well as the multiple scenarios with negligible impacts, suggest that coal production with the highest Tongue River Railroad construction cost would not be significantly less than the coal production with the lowest cost of the maximum alternative cost. OEA presents results in Chapter 8, *Coal Production and Transportation Modeling Results*, Chapter 9, *Rail Transportation Routes*, and Chapter 10, *Results of Emissions Forecasts*, using the lowest construction cost of \$416 million³ for the northern alternatives to provide a conservative estimate of the maximum amount of Tongue River coal that would be transported.

The southern alternatives consist of one primary route and one variation. The capital costs for the southern alternatives are estimated to be \$730.0 and \$762.2 million as provided in the August 29, 2014 response from the Applicant to questions from OEA contained in the June 16, 2014 Sixth Information Request. Prior to the cost estimates submitted on August 29, 2014, OEA estimated the costs to be \$698 and \$832 million. OEA used these values because

³ This analysis uses a northern alternative construction cost of \$416 million. The lowest-estimated northern alternative cost was later refined by TRRC to \$403.3 million. OEA reviewed the changes that would occur to the analyses if the \$403.3 million had been used and determined that the results would be materially the same.

the cost estimates submitted on August 29, 2014 represent a conservative over-estimate of coal production.

Similar to the northern alternative results, there would only be small differences in the amount of Tongue River coal that would be transported using this range of costs. Specifically, a maximum cost compared to the minimum cost for the southern alternatives would result in decreased yearly coal production ranging from 0% (scenarios 16, 17, and 20) to 33.9% (scenario 12). The range of the impact, as well as the multiple scenarios with negligible impacts, suggests that coal production with the highest Tongue River Railroad construction cost would not be significantly less than the coal production with the lowest cost of the maximum alternative cost. OEA presents results in Chapter 8, *Coal Production and Transportation Modeling Results*, Chapter 9, *Rail Transportation Routes*, and Chapter 10, *Results of Emissions Forecasts*, using the lowest construction cost of \$698 million for the same reason as in the northern alternatives.

There are two key differences between the northern and southern alternatives.

- The southern alternatives would have access to the Canyon Creek deposit. This is because the southern alternatives would intersect the eastern edge of the Canyon Creek deposit, which would have access to the proposed rail line through the development of a rail spur.
- The rail distances to potential end-use destinations would vary. The northern alternatives generally would have a distance advantage to regions northeast and northwest of the Tongue River region, as compared to Wyoming Powder River Basin coal mines and the southern alternatives. The southern alternatives generally would have a distance advantage to regions southeast and southwest of the Tongue River region. For example, the northern alternatives would have a rail advantage of 55 miles over the southern alternatives when comparing routes from the Tongue River region to the Pacific Northwest terminals. The northern alternatives would have a rail advantage of between 200 and 300 miles over the southern alternatives when comparing routes from the Tongue River region to the Upper Midwest, which includes plants in Michigan, Minnesota, and Wisconsin.

OEA analyzed the costs of constructing the northern and southern alternatives to determine if the assumed range of capital costs would affect the level of coal production.

The No-Action Alternative assumes that the proposed rail line would not be built and would not induce additional coal mining. The No-Action Alternative provides a basis for comparing scenarios where the only difference is in the inclusion of the Tongue River Railroad. This allows for the impact of the proposed rail line to be analyzed in isolation.

7.3.2 Production Level

OEA modeled coal production at low, medium, and high levels, as detailed in Section 3.3 *Marketable Coal Production Scenarios*. The low and medium production levels were the

same for the northern alternatives and the southern alternatives. The high production level was different for the southern alternatives and the northern alternatives. For the high production level, OEA included the Canyon Creek deposit in the southern alternatives and added the deposit's 22 million tons per year of potential production to the production potential of Otter Creek Mine and Poker Jim Creek–O'Dell Creek deposit. OEA assumed that Canyon Creek coal would be available in the southern alternatives in the high production case only.

One of the simplifying assumptions in the model was that the maximum production quantities for each of the Tongue River mines were modeled without a ramp-up period (as discussed in Chapter 3, *Additional Coal Mining*). For example, the proposed Otter Creek Mine in the low or medium production scenarios was modeled at a production level of 20 million tons in 2018 and all subsequent years of the analysis period (2018 to 2037). The mine permit application indicates that production would be 12 million tons in the first year of production, 16 million tons in the second year, and 20 million tons per year each year after that. This assumption is conservative because it tends to overestimate the Tongue River coal production. OEA selected the 2018 start year to reflect the potential for delays in the Otter Creek Mine permitting process.

Table 7-3 presents the coal production quantities by mine for all alternatives and production levels. Table 7-4 shows the combined coal production quantities for all mines by alternative.

Table 7-3. Production Quantity Specific to Mine or Deposit

Mine/Deposit	Alternatives	Production Level	Production Quantity (million tons per year)	Online Year
Otter Creek	Northern and southern	Low	20	2018
Otter Creek	Northern and southern	Medium	20	2018
Otter Creek	Northern and southern	High	34	2018
Poker Jim Creek–O'Dell Creek	Northern and southern	Low	0	2023
Poker Jim Creek–O'Dell Creek	Northern and southern	Medium	12	2023
Poker Jim Creek–O'Dell Creek	Northern and southern	High	16	2023
Canyon Creek	Southern	Low	0	2030
Canyon Creek	Southern	Medium	0	2030
Canyon Creek	Southern	High	22	2030

Table 7-4. Maximum Production for All Alternatives and Production-Level Combinations (million tons per year)

Year	No-Action Alternative	Northern Alternatives			Southern Alternatives		
		Low	Medium	High	Low	Medium	High
2016	0	0	0	0	0	0	0
2018	0	20	20	34	20	20	34
2023	0	20	32	50	20	32	50
2030	0	20	32	50	20	32	72
2037	0	20	32	50	20	32	72

7.3.3 Terminal Growth Capacity

OEA modeled Pacific Northwest export capability with three levels of terminal growth capacity: zero, medium, and high. The zero-growth case assumes no change to the current annual Powder River Basin coal exports of 8 million tons. As discussed in Chapter 4, *Proposed Coal Export Terminals and Expansions*, four Pacific Northwest terminals are proposed to be expanded or built (Table 7-5).

Table 7-5. Proposed Pacific Northwest Terminal, Coal Export Capacity (million tons per year)

Terminal	Location	Coal Export Capacity (million tons per year)
Gateway Pacific	Cherry Point, Washington	53
Millennium Bulk	Longview, Washington	48
Coyote Island	Boardman, Oregon	9
Fraser Surrey Docks	Vancouver, British Columbia	4
Total		114

The total proposed additional export capacity would be 114 million tons per year. Under the high growth case, OEA assumed that current export levels of 8 million tons per year in 2013 would increase to half of the maximum proposed capacity (65 million tons per year) by 2018 and would reach the full export capacity (122 million tons per year) by 2023. This gradual increase reflects the uncertainty of project construction, as none of the projects is fully permitted. The medium growth case assumed that some of these projects might be cancelled, and that half of the eventual 2018 and 2023 export capacity would be reached. Table 7-6 summarizes the Pacific Northwest terminal capacity under each of the growth cases.

Table 7-6. Projected Pacific Northwest Export Capacity (million tons per year)

Year	Zero Growth	Medium Growth	High Growth
2016	8	8	8
2018	8	32.5	65
2023	8	61	122
2030	8	61	122
2037	8	61	122

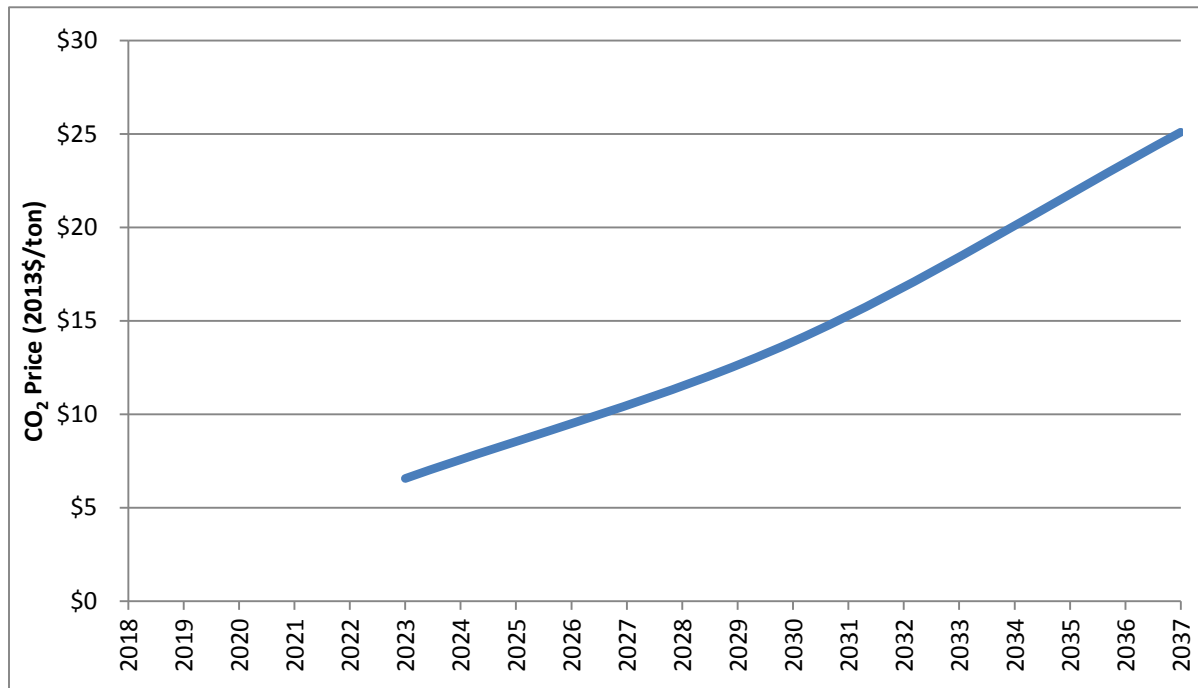
7.4 Carbon Dioxide Control Scenarios

OEA's CO₂ control scenarios examine whether coal from the Tongue River area could be produced economically under more adverse domestic market conditions. The costs of managing CO₂ emissions makes coal less economical than natural gas and tends to lower the demand for coal and suppress coal prices.

A CO₂ price for the power sector begins in 2023 in the scenarios OEA modeled. This relatively late date reflects the lack of political initiative, in early 2013 when the modeling was conducted, to implement a program for managing CO₂ emissions in the near future. The price is based on a probability-weighted forecast of a utility-only cap-and-trade program. The utility program is based on the reductions that would be required under the Kerry-Lieberman legislative proposal,⁴ prorated to the power sector emissions levels. OEA assumed that the probability of a national, utility-only greenhouse gas emissions program would increase over time with a CO₂ price rising from approximately \$7 per ton in 2023 to \$25 per ton in 2037 (2013 dollars) (Figure 7-1).

⁴ The Kerry-Lieberman initiative proposes a sector-wide approach to reductions in carbon emissions, targeting 17% below 2005 levels by 2020.

Figure 7-1. Carbon Dioxide Price (2013 dollars per ton)



7.4.1 Recent Carbon Dioxide Policy and Regulations

The probability of regulations limiting CO₂ has increased since OEA initiated the modeling for this analysis. On June 25, 2013, President Obama released his plan to reach his stated goal of a 17% reduction in U.S. greenhouse gas emissions below 2005 levels by 2020. The plan describes in broad terms how the Administration plans to reduce emissions across the economy.

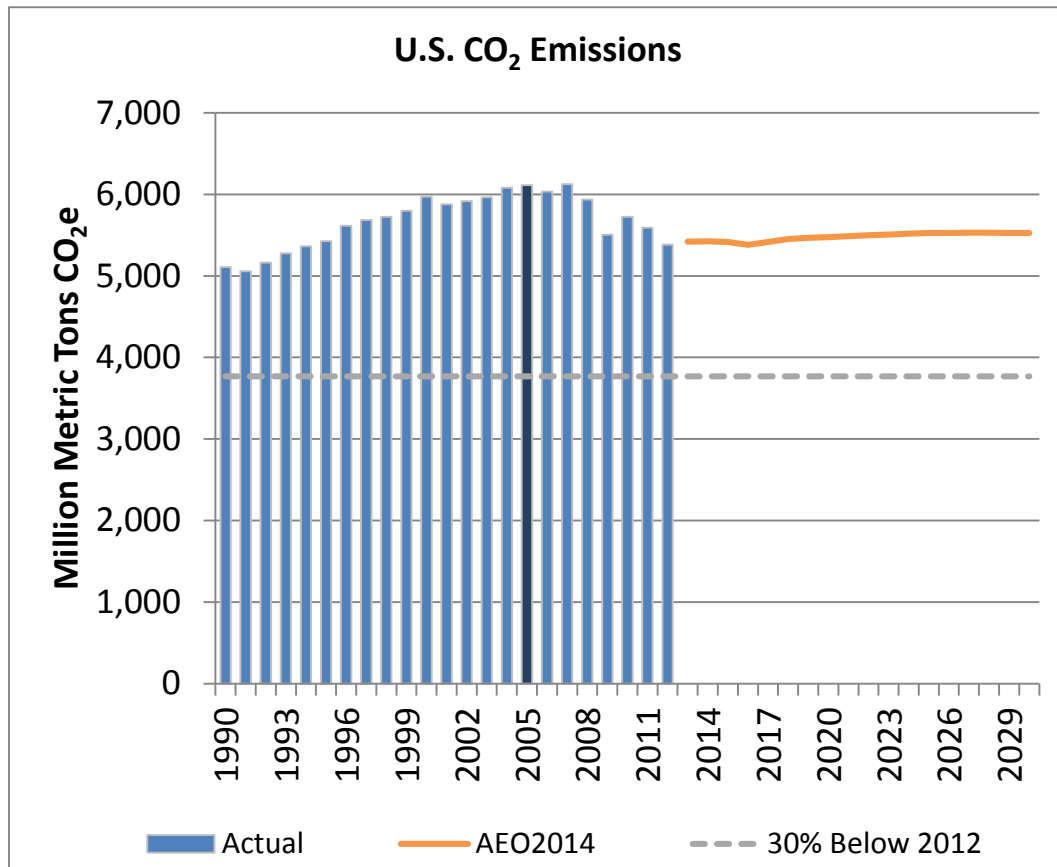
Most relevant to generators, the president intends to complete or initiate action on emissions from fossil-fired generators through U.S. Environmental Protection Agency (USEPA) regulation under the Clean Air Act. USEPA released a revised proposal to regulate new sources on September 20, 2013. USEPA released a proposed rule on June 2, 2014, to reduce emissions at existing sources, with the final rule due during the summer of 2015. The proposed rule is designed to reduce CO₂ emissions by 30% by 2030 from a 2012 baseline. The reductions will be obtained through a variety of measures that include reductions at and retirements of fossil-fired power plants.

Under USEPA's plan, it will set guidelines and the states will plan to achieve compliance through State Implementation Plans. USEPA will review the plans and approve or require changes (or impose a Federal Implementation Plan). USEPA has discussed options ranging from efficiency improvements by generating units to state-based trading programs.

Figure 7-2 shows only CO₂ emissions from energy consumption. The president's plan covers five other greenhouse gases, but CO₂ is the most dominant in terms of absolute quantity and drives the trend for total greenhouse gas emissions. The U.S. Energy Information

Administration (EIA) (2014) projects that CO₂ emissions will grow slowly through 2028, absent any federal CO₂ regulation, and will be about 3% above 2012 levels by 2030.

Figure 7-2. U.S. Carbon Dioxide Emissions



7.5 Natural Gas Price Scenarios

On an equivalent energy basis, minemouth coal has historically been cheaper than natural gas. Historical Henry Hub natural gas spot prices ranged from \$2.75 per million British thermal units (MMBtu) to \$10.29 per MMBtu in real 2012 dollars for the past decade (yearly average) (Bloomberg 2013) (Figure 7-3). Prices for Wyoming Powder River Basin coal with a heat content of 8,800 Btu per pound (17.6 MMBtu per ton) have ranged from \$7.56 per ton to \$14.93 per ton in real 2012 dollars. Converting the dollars-per-ton coal prices to dollars-per-MMBtu results in a price range of \$0.43 per MMBtu to \$0.85 per MMBtu in real 2012 dollars for the past decade (yearly average) (Bloomberg 2013) (Figure 7-4).

Because of high transportation costs, coal competes with natural gas regionally and across different situations (e.g., existing and new plant). Powder River Basin coal transportation costs are typically 40 to 67% of the final delivered coal cost. In most cases, delivered coal prices are still lower than delivered natural gas prices, and are preferred for existing generators. Generators typically make fuel choices based on the cost to generate power using

each fuel, which is calculated by multiplying the fuel cost (dollars per MMBtu) by the heat rate (Btu per kilowatt hour) of the plant in question. For example, if delivered coal costs are \$3.00 per MMBtu and the heat rate at a coal plant is 10,000 Btu per kilowatt hour, then the cost of generation is \$30 per megawatt hour. Continuing the example, if delivered natural gas costs are \$4.5 per MMBtu and the heat rate at a combined cycle plant is 7,000 Btu per kilowatt hour, and then the cost of generation is \$31.5 per megawatt hour. In this example, the coal plant is more economical; however, small changes in fuel costs or heat rate could swing the balance such that the combined cycle plant is more economical.

Figure 7-3. Historical Henry Hub Natural Gas Spot Prices, Yearly Average (\$/MMBtu)

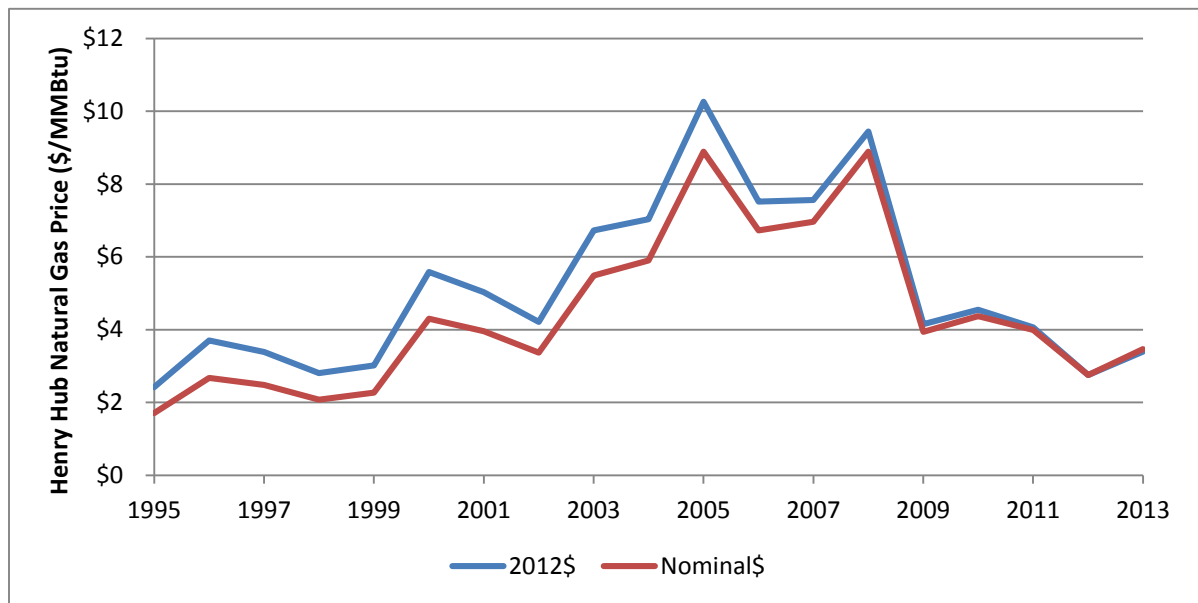
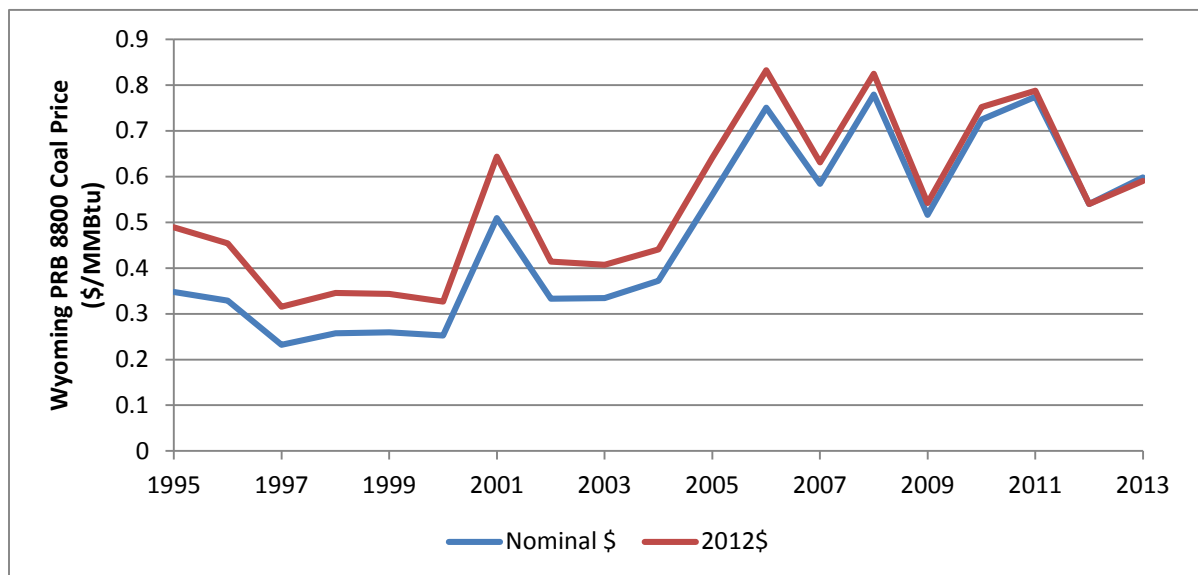


Figure 7-4. Historical Wyoming Powder River Basin 8800 Coal Prices, Yearly Average (\$/MMBtu)



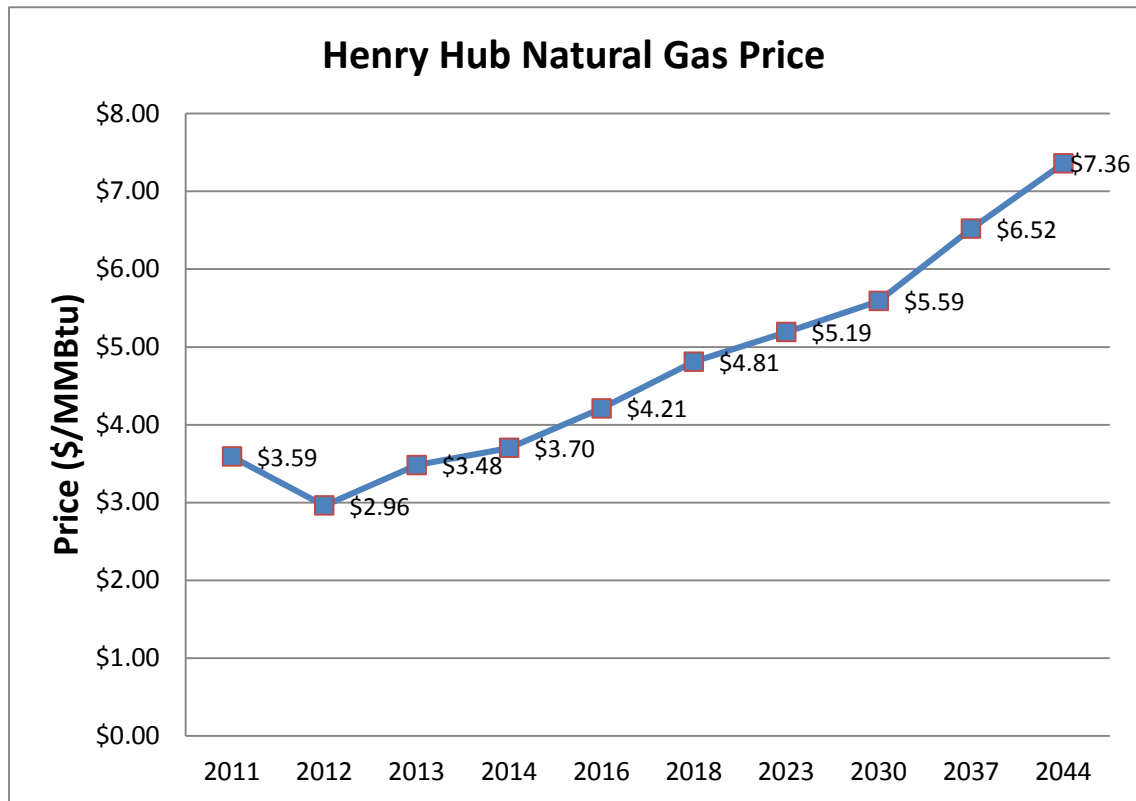
Historically, existing coal generation outcompeted existing natural gas generation. However, in 2012, natural gas prices were lower on a real and nominal basis than any time since 2000 (Table 7-7). In some markets, notably eastern U.S. markets, existing natural gas plants were outcompeting existing coal plants. This lowered coal demand and prices. The low natural gas prices reflected unusually warm winter conditions and increased shale gas production. These two factors reduced demand and increased supply, which resulted in low natural gas prices. Since then, natural gas prices have recovered somewhat (\$3.68 per MMBtu by September 2013) and coal plants are generally more economically viable than natural gas-fired combined cycle plants. Nonetheless, competition from natural gas is an important factor in the coal market.

Table 7-7. Historical Henry Hub Natural Gas Prices (\$/MMBtu)

Year	Real 2012 \$	Nominal \$
2000	5.61	4.30
2001	5.05	3.96
2002	4.23	3.37
2003	6.75	5.49
2004	7.06	5.90
2005	10.29	8.89
2006	7.54	6.73
2007	7.59	6.97
2008	9.48	8.89
2009	4.16	3.94
2010	4.56	4.37
2011	4.08	4.00
2012	2.74	2.75
Average	6.09	5.35
Notes:		
Source: Bloomberg 2013		

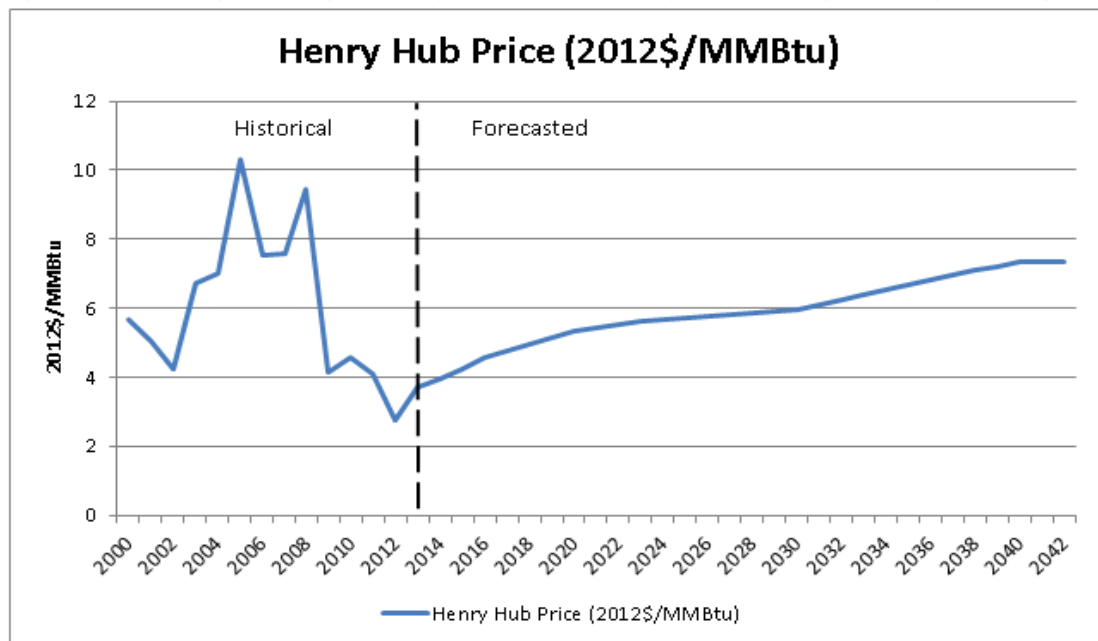
OEA used a projected natural gas forecast for most scenarios (Figures 7-5 and 7-6). The natural gas prices depend on the level of natural gas consumption. These prices also depend on whether there is a CO₂ price. A CO₂ price disadvantages coal relative to natural gas, as the CO₂ emission rate for coal is approximately double that of natural gas. Thus, a CO₂ price drives greater natural gas consumption, which results in higher natural gas prices.

Figure 7-5. Natural Gas Prices



Note: Natural gas prices projected to increase at 2.4% compound annual growth rate from 2013 to 2044 (OEA analysis).

Figure 7-6. Natural Gas Prices (Henry Hub) Historical and OEA Forecast

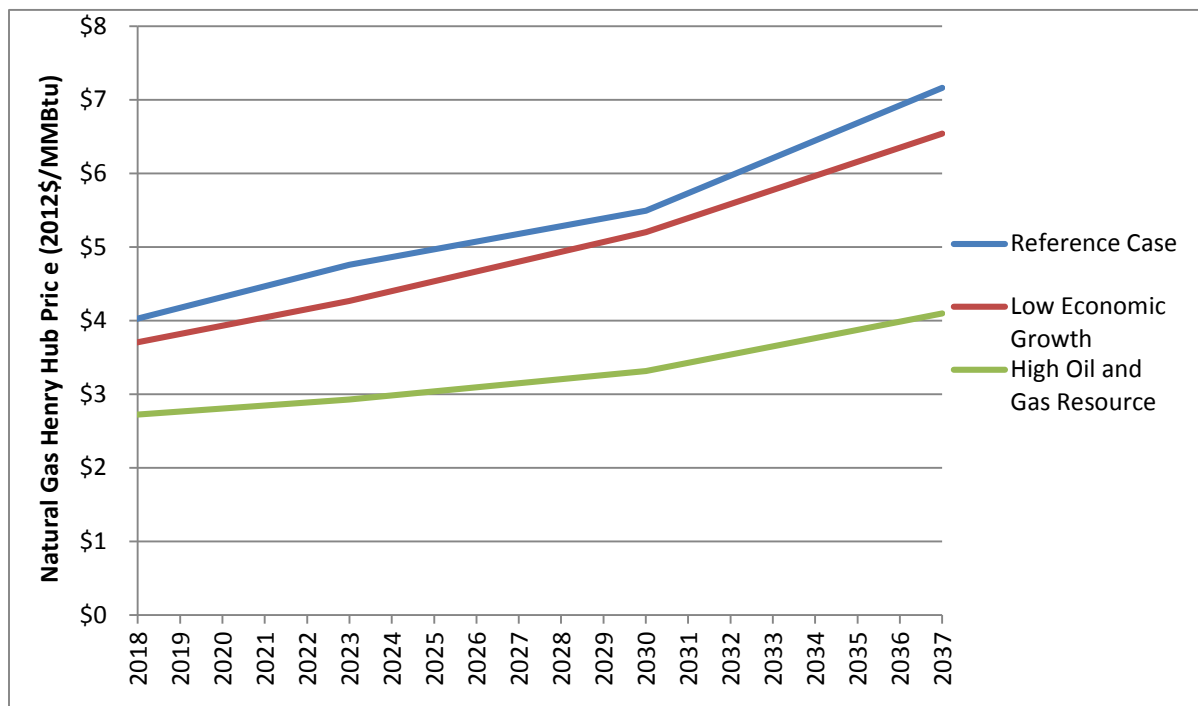


Source: Historical data- Bloomberg, Forecast Data - ICF

The sensitivity case with low natural gas prices is more informative than a case with high natural gas prices. This is because low natural gas prices increase competition with coal. If Tongue River coal is economically competitive in the case with projected natural gas prices, then it may or may not be competitive in the case with low natural gas prices, but it will certainly be more competitive in the case with high natural gas prices. As discussed in Chapter 8, *Coal Production and Transportation Modeling Results*, with projected natural gas prices, Tongue River coal appears economically competitive, with coal production developed at the maximum in the scenarios analyzed. Thus, a high natural gas price case was not explored.

OEA used the EIA *Annual Energy Outlook* (2013) to determine the natural gas prices for the low natural gas price scenarios. Specifically, OEA reviewed two low natural gas price cases plus the reference case from the EIA 2013 Annual Energy Outlook.⁵ The EIA prices and projections for future growth are industry benchmarks. Two cases used in EIA models, the Low Economic Growth and the High Oil and Gas Resource cases, have lower natural gas prices compared to the reference case. Figure 7-7 shows the natural gas prices for the two EIA low natural gas price cases and the EIA reference case.

Figure 7-7. U.S. Energy Information Administration *Annual Energy Outlook* 2013 Natural Gas Prices (\$/MMBtu)



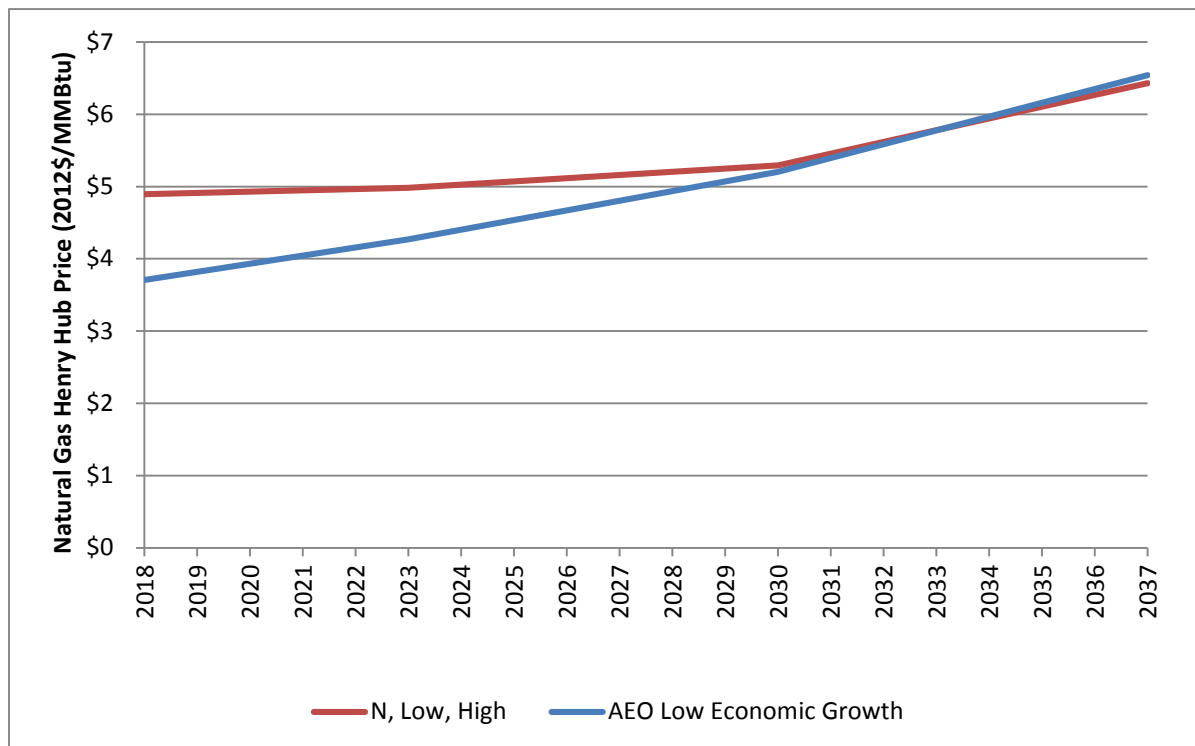
OEA rejected the high oil and gas resource case used by EIA, because it has unrealistically low gas prices, since current spot natural prices are already above the price projection

⁵ The reference case assumes the most likely scenario for natural gas prices going forward, according to the *Annual Energy Outlook* (U.S. Energy Information Administration 2013).

through 2035. Thus, the natural gas prices in the Low Economic Growth case have been adopted for the low gas price scenarios in this analysis.

Figure 7-8 provides a comparison of the natural gas prices for the northern alternatives, low production, high growth scenario (scenario 5) and the low EIA gas prices. While the low natural gas prices become slightly higher than the base-case natural gas prices in 2037, there is a significant gap in gas prices in the earlier years (2018 through 2030) that translates to an overall increase in gas consumption and an overall decrease in domestic coal consumption from 2018 to 2037.

Figure 7-8. Natural Gas Price Comparison with EIA Annual Energy Outlook Low Economic Growth Case (\$/MMBtu)



7.6 Production Costs

OEA selected two scenarios to test the effect of increases in Tongue River coal production costs on the economic viability of Tongue River coal production: northern alternatives, low production, zero growth (scenario 3) and northern alternatives, high production, high growth (scenario 11). OEA only analyzed northern alternatives under the higher production cost scenario to keep the number of scenarios analyzed manageable and since similar results are expected, and thus analyzing the southern alternatives would not provide new insights. Seven levels of increased production costs (10, 20, 35, 50, 65, 80, and 100% increases) yielded a set of 14 additional production cost sensitivity scenarios. If production costs are

underestimated (Chapter 6, *Coal Production Costs*), these increased production cost sensitivities show the effect of higher production costs on Tongue River coal production.

The low production level for the northern alternatives represents the Otter Creek Mine permit application with 20 million tons per year of production, while the high production level represents a higher level of production from the Otter Creek Mine plus production from the Poker Jim Creek–O’Dell Creek deposit starting in 2023. Cost sensitivity results for the northern alternatives, medium production scenarios can be interpolated from the low and high production results. Similarly, the two extremes for terminal capacity growth (zero and high) were selected for their range in the cost sensitivity model runs. Chapter 8, *Coal Production and Transportation Modeling Results*, provides the production cost sensitivity results.

7.7 Pacific Basin Delivered Coal Prices

OEA explored the competitiveness of Powder River Basin coal exports relative to international coals by decreasing international coal production costs to achieve lower delivered coal costs. Production costs for Pacific Basin coal suppliers were decreased by 20, 30, 40, and 50%. To observe the largest difference in Tongue River coal production and export levels, OEA used the northern alternatives, high production, high port growth scenario (scenario 11) as the test case. Chapter 8, *Coal Production and Transportation Modeling Results*, provides the results of this modeled test case.

Chapter 8

Coal Production and Transportation Modeling Results

8.1 Introduction

This chapter presents the coal production and transportation modeling results with an emphasis on Tongue River coal production levels, coal displacement, coal distribution patterns, and rail transportation volumes. Chapter 10, *Results of Emissions Forecasts*, presents results for potential air emissions.

The proposed rail line could cause changes at the following scales of coal production.

- Tongue River coal production
- Powder River Basin coal production
- U.S. coal production
- Worldwide coal production

The key questions related to coal mining and rail traffic that could take place with the development of the proposed rail line can be stated as follows.

- Would construction and operation of the proposed rail line induce additional coal production in the Tongue River area?
- Would Tongue River coal displace coal production elsewhere in the Powder River Basin, in the United States, or in the world?
- Would construction and operation of the proposed rail line affect the level of coal exports?
- Where would Tongue River coal be distributed to in the United States?
- How would Tongue River coal production affect rail traffic?
- How would the uncertainties of production costs, natural gas prices, and carbon dioxide (CO₂) prices affect Tongue River coal production and export?
- How would total Powder River Basin coal production and transport change across Tongue River coal production and export terminal capacity growth scenarios?

The following subsections address these, first by topic, and then by alternative and scenario, based on the modeling results.

- Tongue River Coal Production
- Displaced Coal Production

- Coal Distribution
- Model Results by Scenarios
- Natural Gas and Carbon Dioxide Price Sensitivities
- Production Cost Sensitivity
- Pacific Basin Coal Production Cost Sensitivity

8.2 Tongue River Coal Production

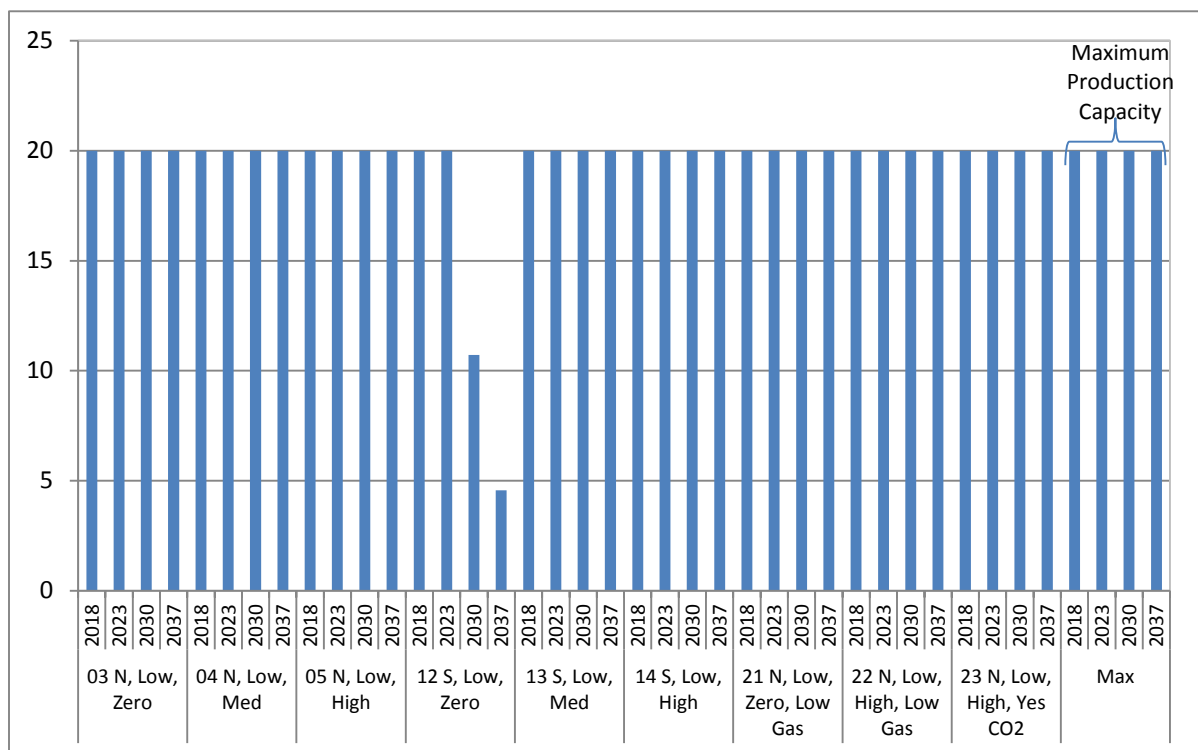
OEA concludes that there is a range of likely Tongue River coal production levels if the Tongue River Railroad is constructed. To provide perspective, it is useful to summarize the average annual Tongue River coal production for 2018 to 2037, which would be 30.6 million tons per year across all 21 mutually exclusive scenarios (e.g., both northern and southern alternatives), ranging from 13.8 million tons per year (scenario 12) to 57 million tons per year (scenarios 19 and 20). OEA also concludes that the range of a single year's production is 4.6 million tons per year (scenario 12, 2037) to 72.0 million tons per year (scenarios 19 and 20, 2030 and 2037), also across all 21 scenarios. Production would be highest in the scenarios of high potential production and high terminal capacity growth.

OEA concludes that annual production would vary according to the alternative. If a northern alternative is approved, annual production would range from 20 million tons of coal per year (scenarios 3, 4, and 5) to 50 million tons per year (scenarios 10 and 11), depending on the scenario. Under the northern alternatives, the proposed Otter Creek Mine and the Poker Creek–O'Dell Creek deposit could produce coal. If a southern alternative is approved, annual production would range from 4.6 million tons per year (scenario 12) to 72 million tons per year (scenarios 19 and 20), depending on the scenario. Under these alternatives, the proposed Otter Creek Mine and both the Poker Jim Creek–O'Dell Creek deposit and the Canyon Creek deposit could produce coal. Figures 8-1 through 8-3 present these annual production ranges.

These figures present model outputs of Tongue River coal production by scenario and by model year (Chapter 7, *Scenarios*, provides a description of scenarios and scenario labels and Chapter 5, *Model Framework, Methods, and Key Assumptions*, provides a discussion of model run years). The figures are grouped by production levels. The figures present all of the scenarios with low production, medium production, and high production in separate, respective groups. The figures also present the high production scenarios for the northern and southern alternatives separately. The maximum production level is different at the high production level between the northern and southern alternatives because of Canyon Creek's availability in the southern alternatives at high production levels only. The production level maximums are also presented for each of the four run years (2018, 2023, 2030, 2037), on the right side of the charts.

Figures 8-1 through 8-3 show Tongue River coal production over time for each of the scenarios.¹ The figures also show whether certain scenario-year combinations would result in production levels that are either completely uneconomical (i.e., a production level of zero, which is never the case in the scenarios analyzed) or only somewhat economical, such as in the case of scenario 12 in 2030 and 2037. Scenarios that are only somewhat economical have a production level greater than zero but less than the maximum yearly production level, which occurs in one northern alternative scenario (scenario 9) and five southern alternative scenarios (scenarios 12, 15, 16, 17, and 18). Figure 8-4 shows the average and maximum coal production for all scenarios.

Figure 8-1. Tongue River Coal Production and Maximum Production Capacity, by Run Year for Low Production Scenarios (million tons per year)



¹ The economic feasibility of coal production at a mine depends on variables such as increasing stripping ratios over time, competition with natural gas and other fuels, as well as short-term supply and demand shifts. These variables, in isolation or in combination, could result in the production capacity of a mine not reaching maximum capacity in any given year.

Figure 8-2. Tongue River Coal Production and Maximum Production Capacity, by Run Year for Medium Production Scenarios (million tons per year)

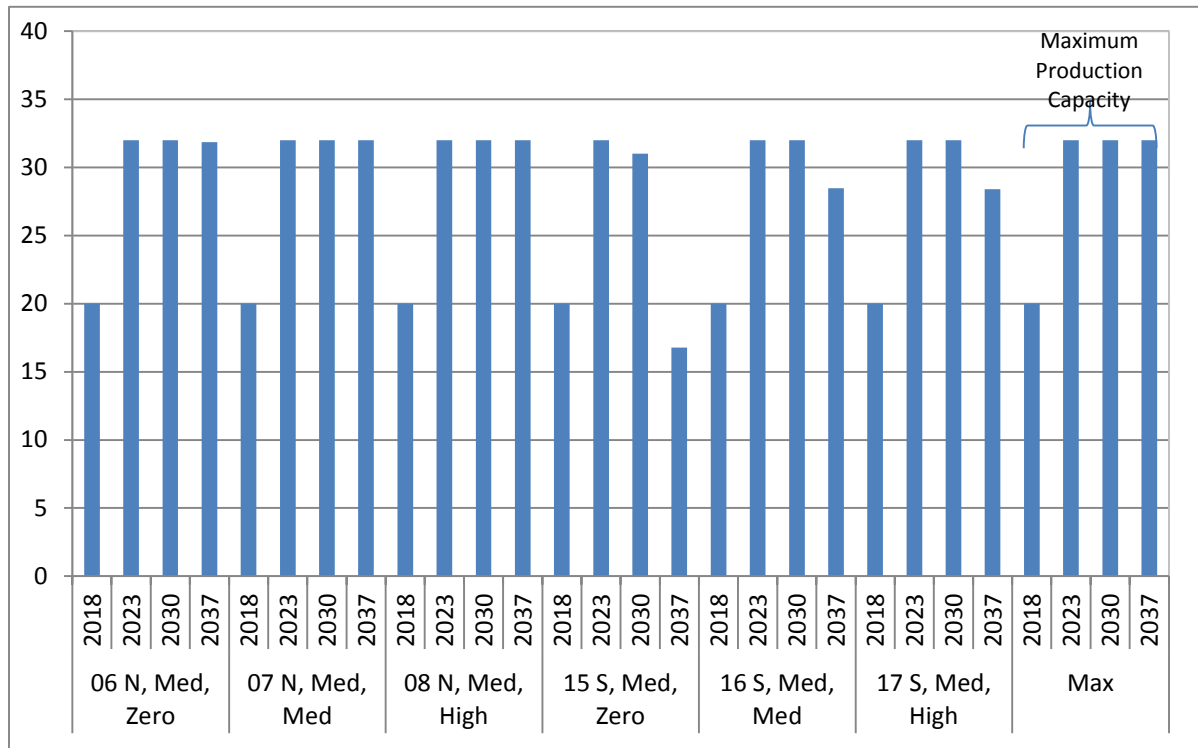


Figure 8-3. Tongue River Coal Production and Maximum Production Capacity, by Run Year for High Production Scenarios (million tons per year)

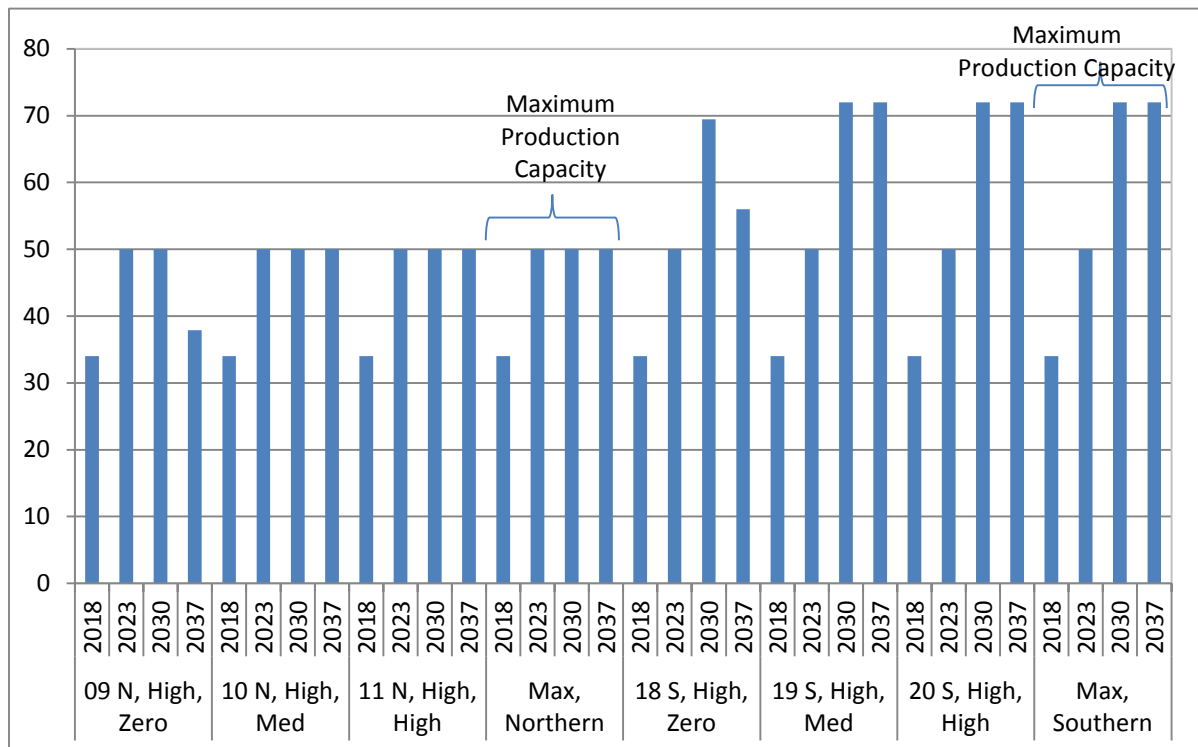
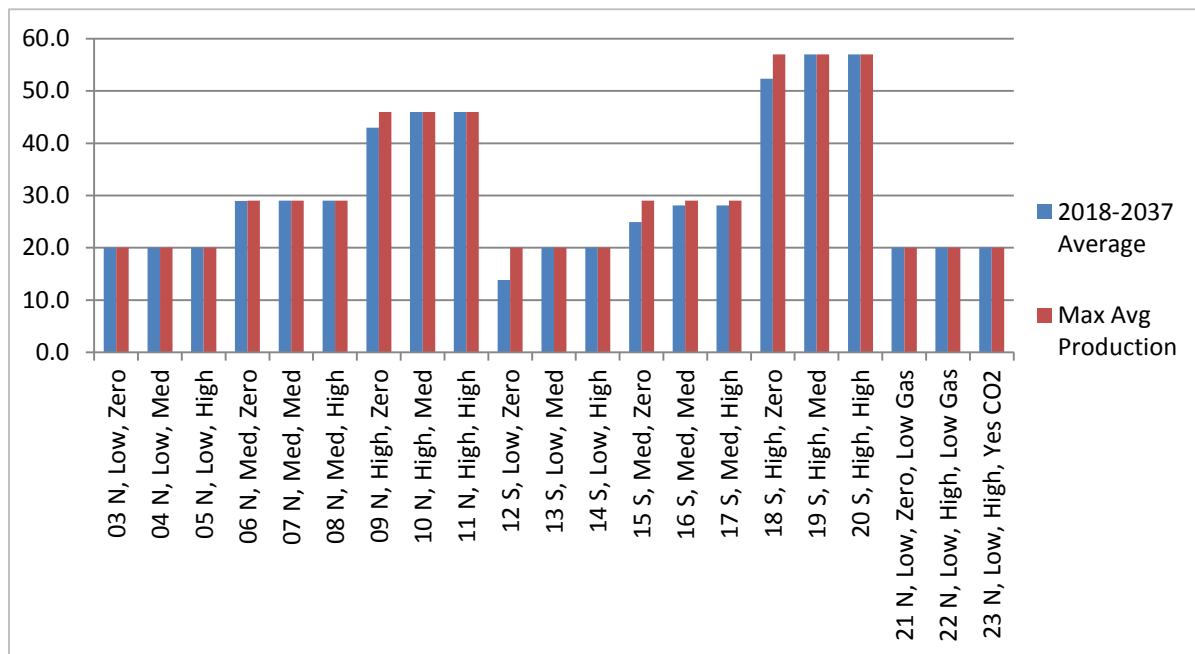


Figure 8-4. Tongue River Coal Production and Maximum Production Capacity (million tons/year)



The northern alternatives would be more economically viable in general because they would have shorter distances to several key markets. However, the southern alternatives would have access to an additional coal deposit at Canyon Creek, which would allow for a higher maximum yearly production. The 2018 to 2037 yearly annual average coal production would be 28.5 million tons per year for the northern alternative scenarios and 33.5 million tons per year for the southern alternative scenarios. Average annual production for the northern alternatives would range from 20 million tons per year (scenarios 3, 4, and 5) to 46 million tons per year (scenarios 10 and 11.) Average annual production for the southern alternatives would range from 13.8 million tons per year (scenario 12) to 57 million tons per year (scenarios 19 and 20.) The single-year production for the northern alternatives would range from 20 million tons per year (scenarios 3, 4, and 5, all years) to 57 million tons per year (scenarios 10 and 11, all years.) The single-year production for the southern alternatives would range from 4.6 million tons per year (scenario 12, 2037) to 72 million tons per year (scenarios 19 and 20, 2030 and 2037.)

A similar aggregate comparison shows that in all but seven of the 21 scenarios, the Tongue River coal production would be economically produced at the maximum production capacity. In the seven cases where maximum production was not economical in each year, total production over the 2018 to 2037 period would range from 70.6% (scenario 12) to 99.9% (scenario 6) of the maximum production capacity.² The cumulative production over the 20-year period varied between 400 million tons (scenarios 3, 4, 5, 12, 13, 14, 21, 22, and 23) and 1,140 million tons (scenario 18, 19, and 20), depending on the scenario. Accordingly,

² Maximum production was not economical in each year due to a combination of two factors, namely, higher railroad construction costs and medium to zero port growth, which makes for a tighter, more competitive marketplace.

OEA concludes that Tongue River coal would be economically competitive under a wide range of cases.

Tongue River coal would be less competitive in later years, especially in the zero terminal capacity growth cases, than in the earlier years. This is because the model forecasts that Tongue River coal production costs would increase faster than other domestic coal production costs as the initial lower stripping ratio deposits were depleted and deposits with higher stripping ratios are mined.

8.3 Displaced Coal Production

8.3.1 U.S. Coal Production

OEA concludes that Tongue River coal production would primarily displace other U.S. coal production. From 2018 to 2037, across all cases, on average, every ton of Tongue River coal produced would displace 0.76 ton of other Powder River Basin coal and 0.95 ton of all other U.S. coal (e.g., Powder River Basin, Appalachian and Illinois Basin coal). Thus, for each ton of Tongue River coal produced, production of other Powder River Basin coal would decline on average by 0.76 ton and total U.S. non-Tongue River coal production would decline on average by 0.95 ton. The range of displacement of other Powder River Basin coal would range from 0.57 ton for (scenario 14) to 0.88 ton (scenario 4), and the range of displacement of other U.S. coal would range from 0.90 ton (scenario 14) to 1.00 ton (scenario 3).

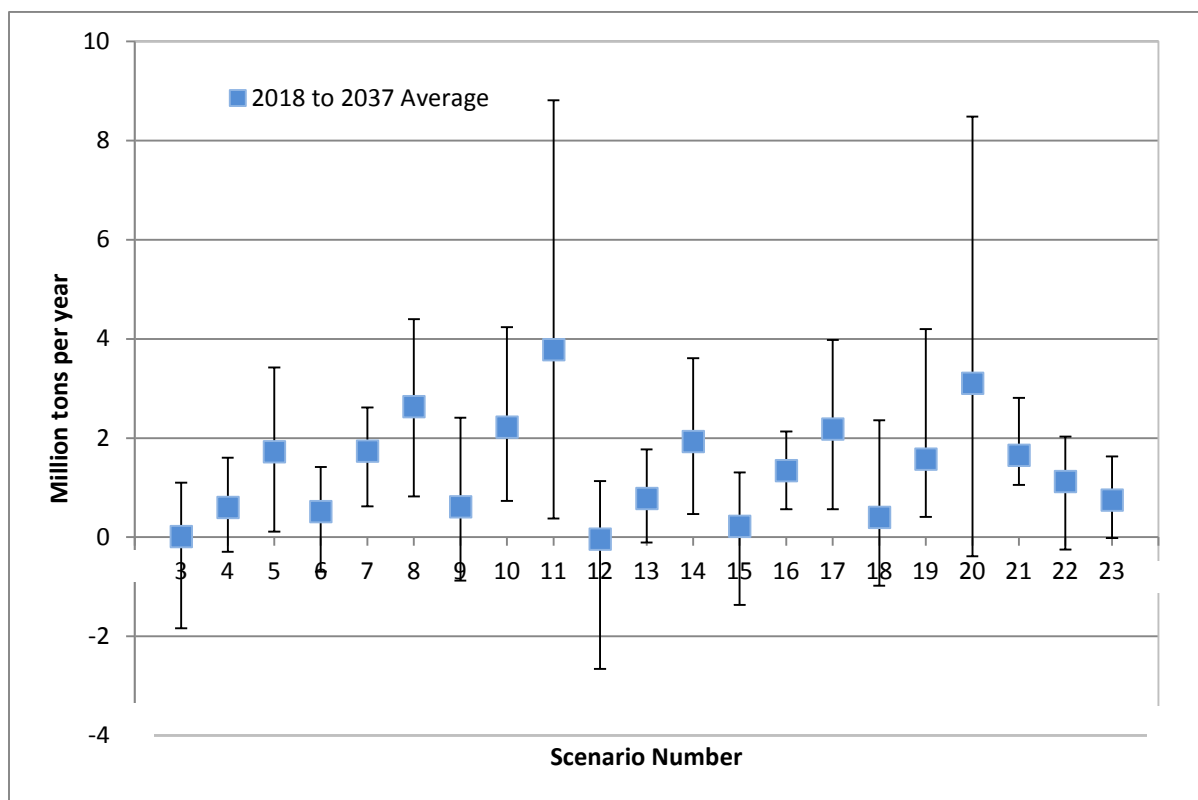
Therefore, production of Tongue River coal would cause total U.S. coal production to increase by 1.4 million tons per year, on average, from 2018 to 2037 (4.6% of 30.6 million tons per year). The range of increase of other Powder River Basin coal production would be from 2.4 million tons per year (scenario 4) to 14.8 million tons per year (scenario 20), and the range of increase of other U.S. coal production would range from 0.0 million tons per year (scenario 3) to 3.8 million tons per year (scenario 11).

OEA concludes that total U.S. coal production would increase between 0.0 (scenario 3) and 3.8 million tons per year (scenario 11) averaged from 2018 to 2037, if the proposed rail line is approved and built and that this range of increase would be small in comparison to U.S. and world coal consumption. From 2018 to 2037, across all six No-Action Alternative scenarios, on average, U.S. coal production would be approximately 1,044 million tons per year. Therefore, the average annual incremental increase in U.S. coal production of 1.4 million tons would equal 0.13% of total U.S. coal production. The incremental increase in U.S. coal production would range from 0.0% (scenario 3) to 0.36% (scenario 11). The maximum single-year increase in U.S. coal production would occur in 2018 (scenario 11) and would equal 0.84% of U.S. coal production for that year. Tongue River coal production would have an even smaller incremental effect on world coal production, in part, because the annual average of world coal production, of approximately 11.4 billion tons per year from 2018 to 2037, is much larger than the average U.S. coal production.

The small impact of the proposed rail line on U.S. and world coal production reflects two factors. First, the cost advantage of producing Tongue River coal would be significant enough to out-compete other coal, but would not be significant enough to noticeably lower delivered coal prices, and hence, would not significantly increase total demand for coal. This, in turn, is partly because the minemouth price of coal is often less than half the delivered cost. Second, the quantities involved would be small compared to the size of the total coal market, and hence, any impact on total incremental demand for coal would be small.

Tongue River coal production primarily would displace other U.S. coal, and would increase total U.S. average annual coal production by 0 to 3.8 million tons (2018 to 2038), depending on the scenario (Figure 8-5). Coal production from other domestic sources would decrease in response to increased Tongue River coal production. The increase in total U.S. coal production in the 21 scenarios would range from 0.0% (scenario 3) to 0.36% (scenario 11) of total U.S. coal production, an extremely small percentage.

Figure 8-5. Change in Total U.S. Coal Production Relative to No-Action Alternative Scenarios, Averaged 2018 to 2037 and Range of Annual Values (million tons/year)

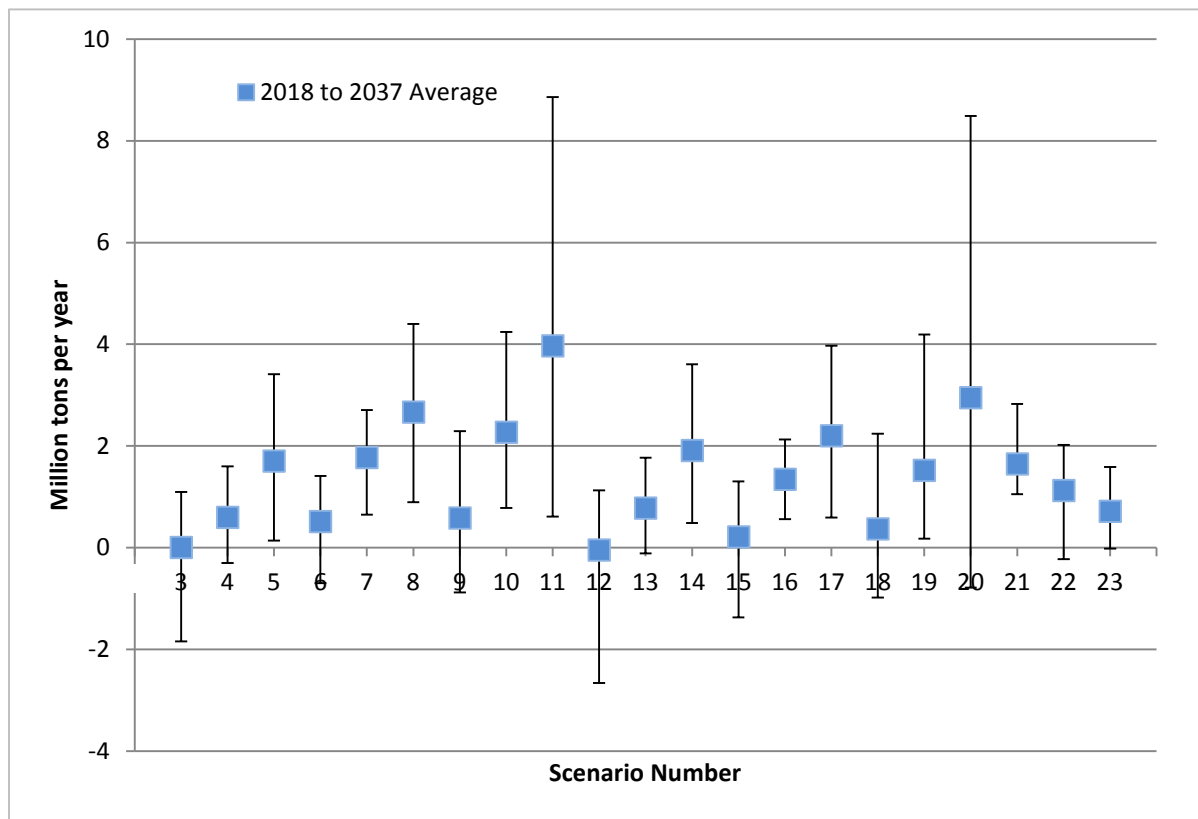


8.3.2 Worldwide Coal Production

OEA's modeling shows that Tongue River coal production would increase worldwide coal production by an average of 0 to 4.0 million tons per year depending on the scenario (Figure 8-6). Most of that maximum increase (3.8 million tons per year out of 4.0 million

tons per year) (scenario 11) would be consumed in the United States. For scenario 11, there would be a small increase (0.2 million tons per year out of 4.0 million tons per year) in international coal production to make up the difference in exported heating value, since the Tongue River coal has a lower heat content than other Powder River Basin coal that is exported.

Figure 8-6. Change in Worldwide Coal Production Relative to No-Action Alternative Scenarios, Averaged 2018 to 2037 and Range of Annual Values (million tons/year)



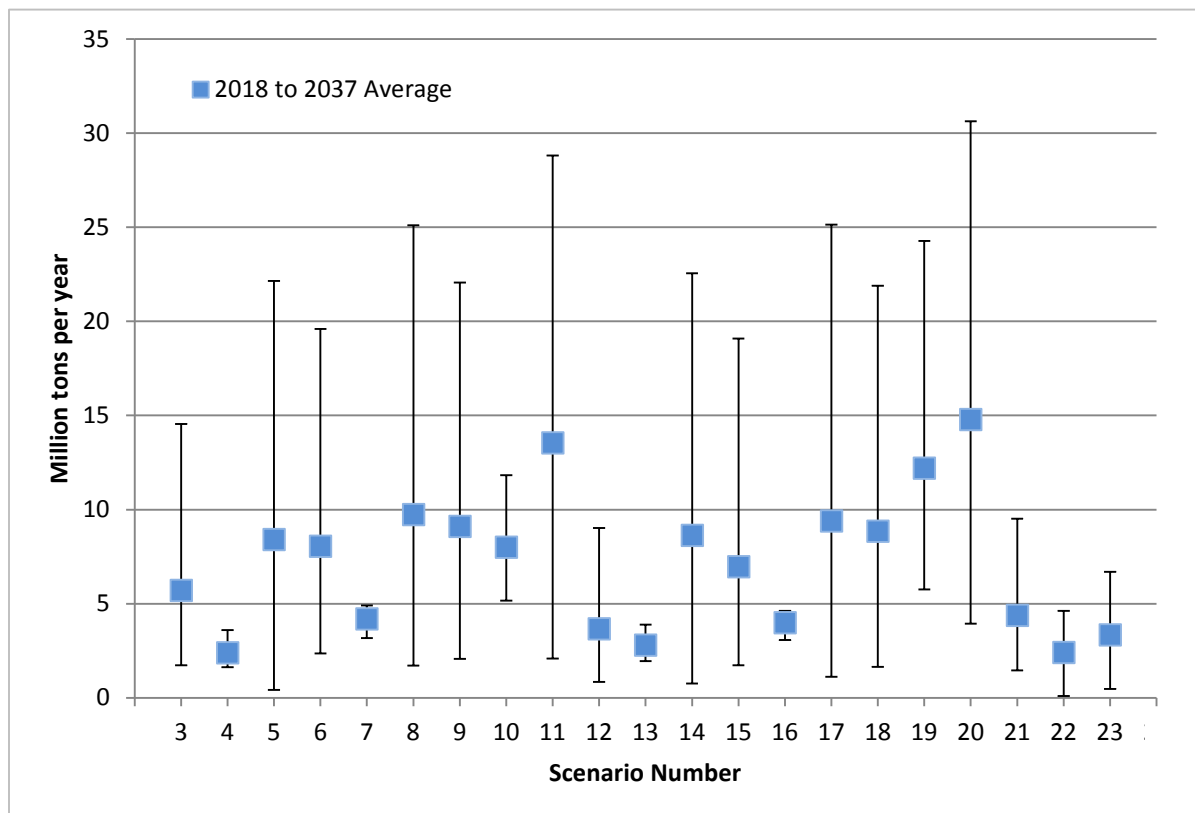
8.3.3 Powder River Basin Coal Production

OEA concludes that the potentially induced Tongue River coal production (on both a tonnage and energy basis) would only modestly increase total Powder River Basin coal production. Increases in overall Powder River Basin coal production would range from 2.4 million tons per year (scenario 4) to 14.8 million tons per year (scenario 20), averaging 7.2 million tons (Figure 8-7). This increase is well below the Tongue River production estimates because the Tongue River coal would displace production at other Montana and Wyoming coal from the Powder River Basin under all scenarios. The cost of Tongue River coal is competitive with other Powder River Basin coal, but is not low enough to induce new demand. Thus, Tongue River coal would compete with other Powder River Basin coal for a relatively fixed demand amount.

In contrast, in the No-Action Alternative scenario with zero terminal capacity growth would be scenario 1, average annual Powder River Basin coal production from 2018 to 2037 would be 478 million tons per year (8.3 trillion British thermal units [Btus]) and would range from 465 million tons per year to 497 million tons per year. On average across the 21 scenarios, for every ton of Tongue River coal produced, 0.76 ton of other Powder River Basin coal would be displaced. Alternately, for every Btu of Tongue River coal produced, 0.76 Btu of other Powder River Basin coal would be displaced. The displacement ranges from 0.57 ton (scenario 14) to 0.88 ton (scenario 4).

The average displacement of 0.76 ton was calculated by averaging the change in total Powder River Basin coal production divided by the Tongue River coal production and subtracting the average from one. For example, in scenario 19, which shows the highest Tongue River coal production at 57 million tons, the increase in total Powder River Basin coal would be 12.2 million tons, and the percent increase would be 21.4% of the Tongue River coal production. In this example, the increase in Tongue River coal production of 57 million tons would be matched by a decrease of 44.8 million tons of other Powder River Basin coal production, and thus 78.6% of the Tongue River coal production would displace other Powder River Basin coal.

Figure 8-7. Powder River Basin Coal Production Relative to No-Action Alternative Scenarios, Averaged 2018 to 2037 and Range of Annual Values (million tons/year)



In sum, Tongue River coal production would have a minor impact on the market for Powder River Basin coal for the following reasons.

- The coal market is very large compared to potential Tongue River coal production.
- Tongue River coal would not be materially less expensive to produce than other Powder River Basin coal.
- Fuel costs are only one component of a generating plant's overall costs, so it is difficult to stimulate more demand at existing power plants with fuel costs that are only slightly lower.

For Tongue River coal to have a greater impact on the market, the supply curve would have to shift enough to induce more coal use, and OEA's modeling shows that this would occur very modestly under the scenarios studied.

8.4 Coal Distribution

This section provides information on expected Tongue River coal distribution, i.e., domestic distribution, exports, and rail traffic.

8.4.1 Domestic Distribution

Tongue River coal would be distributed primarily to the Upper Midwest and secondarily to the Pacific Basin. The Upper Midwest includes the three modeling regions of Great Lakes, East; Great Lakes, West; and Midwest, North; as well as the states of Michigan, Ohio (one coal plant), Wisconsin, and Minnesota. In both the Upper Midwest and Pacific Basin markets, Tongue River coal would primarily displace other Powder River Basin coal, and other U.S. coal. Thus, the net U.S. incremental production change would be incremental to the corresponding No-Action Alternative for all scenarios. For example, on average, the increase in U.S. coal production from Tongue River coal would be 0.13% of the U.S. total coal production. The increase in U.S. coal production would range from 0.0% (scenario 3) to 0.36% (scenario 11).

Based on OEA's modeling, the Upper Midwest would be the primary market for Tongue River coal. Lower quantities of Tongue River coal would also be consumed in the Pacific Northwest. In other words, as Powder River Basin coal with a higher heat content is exported, Tongue River coal would serve domestic demand that would otherwise be filled by other Powder River Basin coal.

8.4.1.1 Deliveries by Region

Figures 8-8 through 8-14 show where Tongue River coal would be delivered, by region and by model year. The figures are presented in groups of three, one for each growth level. In sum, these figures show that Tongue River coal would be delivered primarily to the Upper

Midwest. Tongue River coal would travel from 200 to 300 fewer miles than other Powder River Basin coal to this market. Tongue River coal is also well suited to shorter hauls because its energy content is lower than some other Powder River Basin coal. Because transportation costs are a significant portion of the delivered cost of Powder River Basin coal, lower heat content would result in an overall higher cost per equivalent million Btu. Thus, lower heat content coal tends to be transported shorter distances, as higher heat content coal can be transported farther for the same cost per Btu. As discussed in Section 8.4.2, *Exports*, some Tongue River coal would also be exported to Asia in scenarios with high production levels and high growth.

Figure 8-8 shows the northern alternatives at low production levels for zero, medium, and high export growth (scenarios 3, 4, and 5). Figure 8-9 shows the northern alternatives at medium production levels for zero, medium, and high export growth (scenarios 6, 7, and 8). Figure 8-10 shows the northern alternatives at high production levels for zero, medium, and high export growth (scenarios 9, 10, and 11).

Figure 8-8. Distribution of Tongue River Coal for Northern Alternatives, Low Production: Zero (top chart), Medium (middle chart), and High Export Growth (bottom chart) in million tons/year (scenarios 3, 4, and 5)

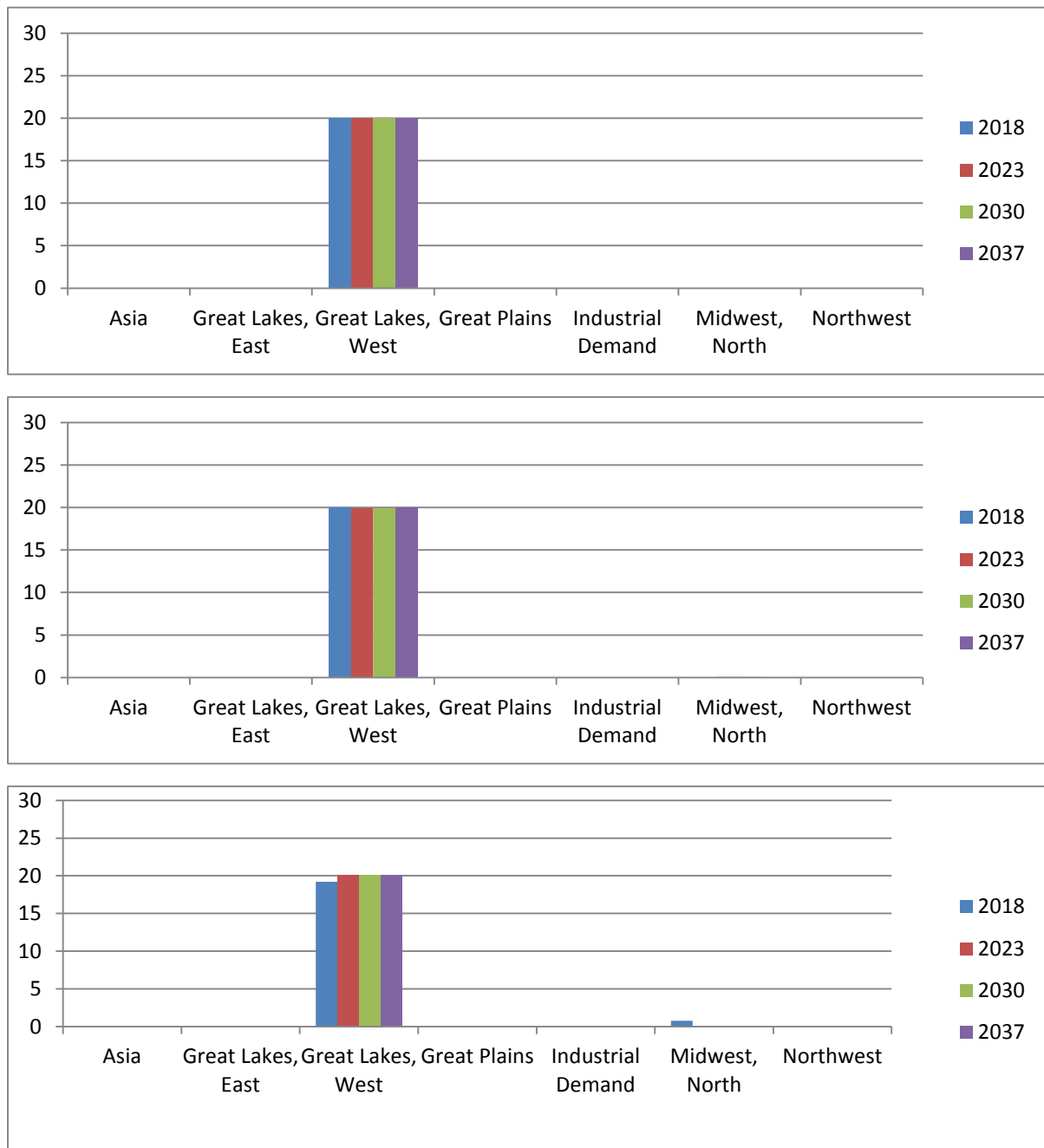


Figure 8-9. Distribution of Tongue River Coal for Northern Alternative, Medium Production: Zero (top chart), Medium (middle chart), and High Growth (bottom chart) in million tons/year (scenarios 6, 7, and 8)

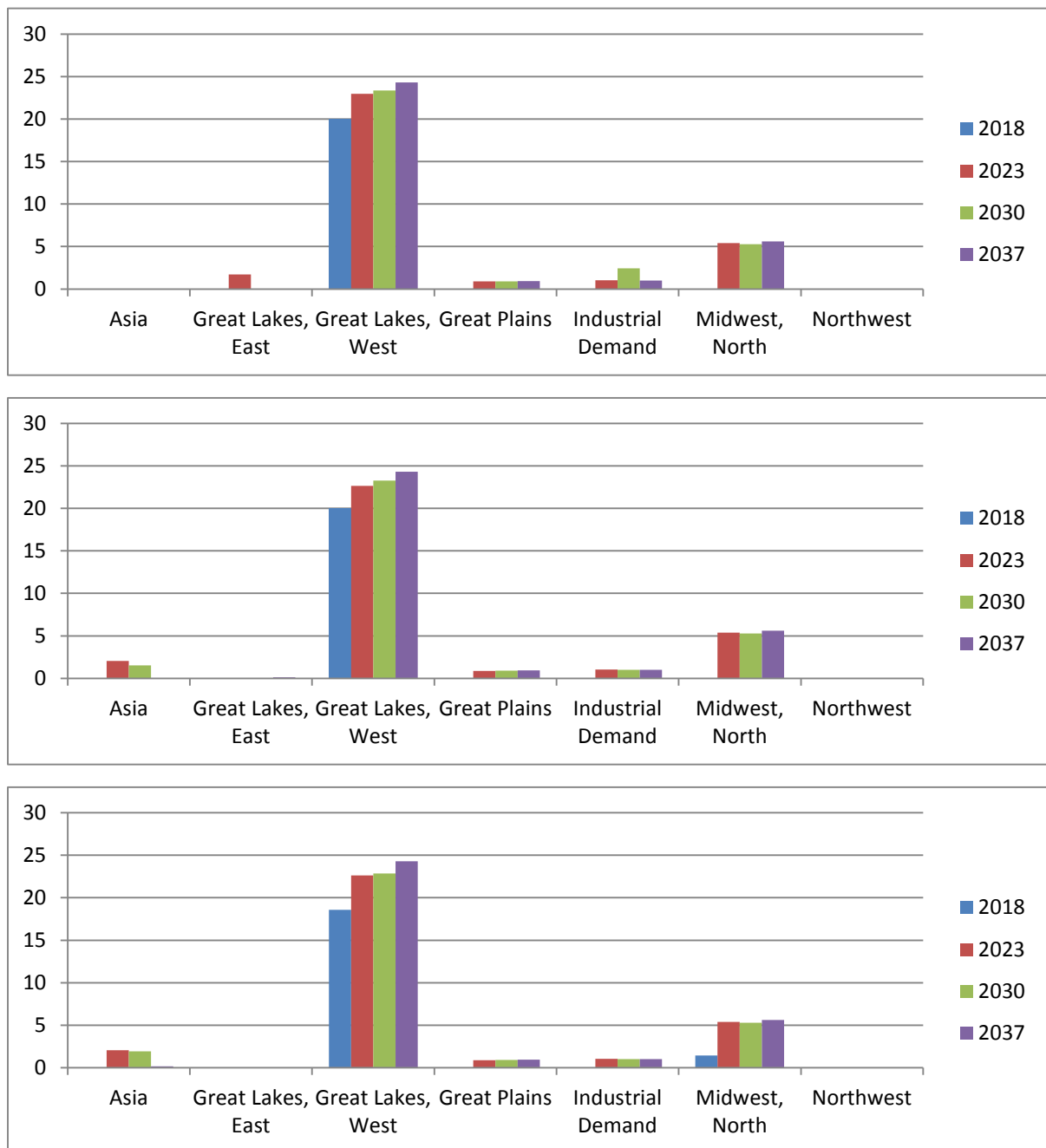


Figure 8-10. Distribution of Tongue River Coal for Northern Alternative, High Production: Zero (top chart), Medium (middle chart), and High Growth (bottom chart) in million tons/year (scenarios 9, 10, and 11)

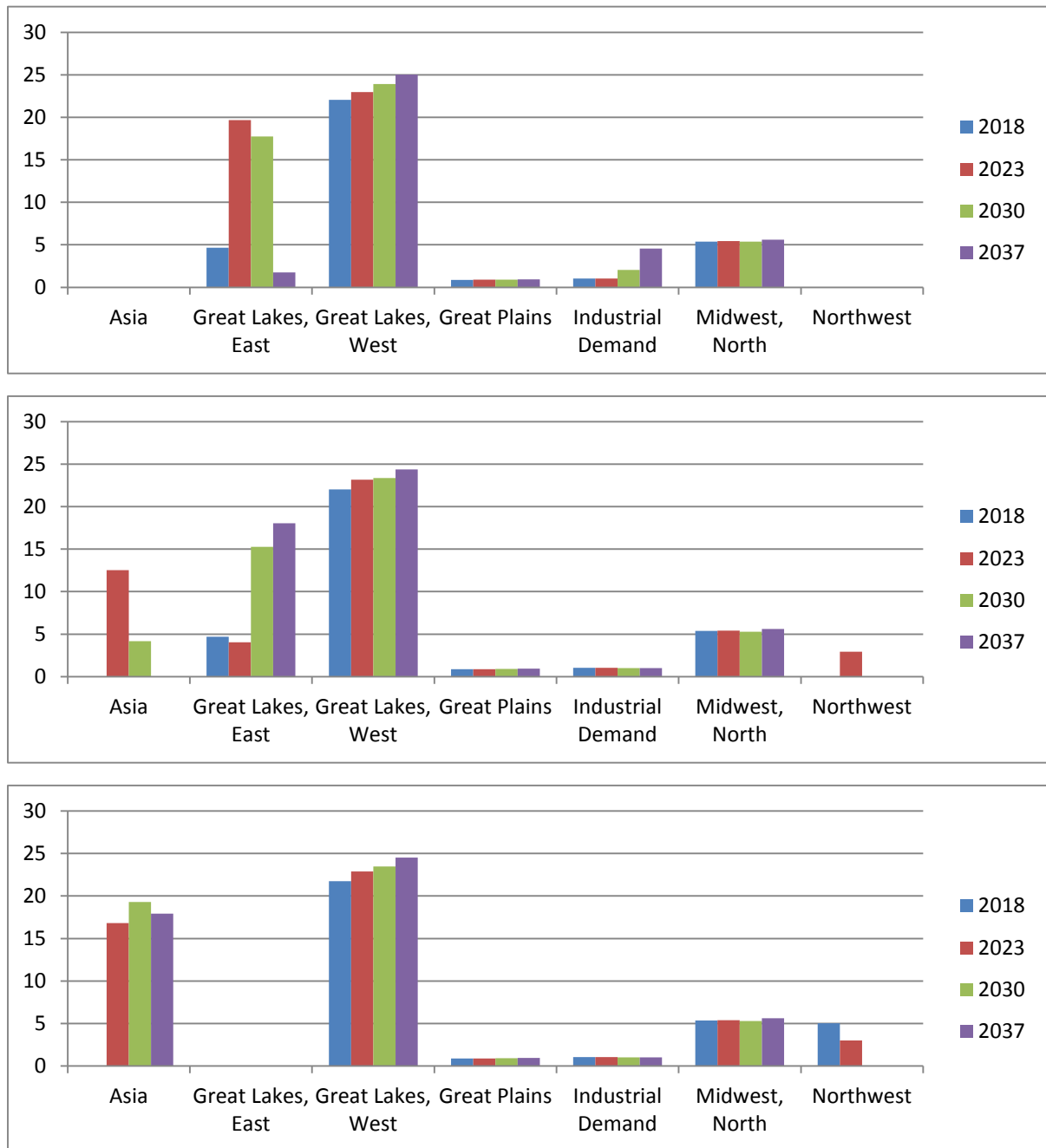


Figure 8-11. Distribution of Tongue River Coal for Northern Alternatives, Low Production: Zero Growth and Low Gas Prices (top chart); High Growth and Low Gas Prices (middle chart); and High Growth and a CO₂ Price (bottom chart) in million tons/year (scenarios 21, 22, and 23)

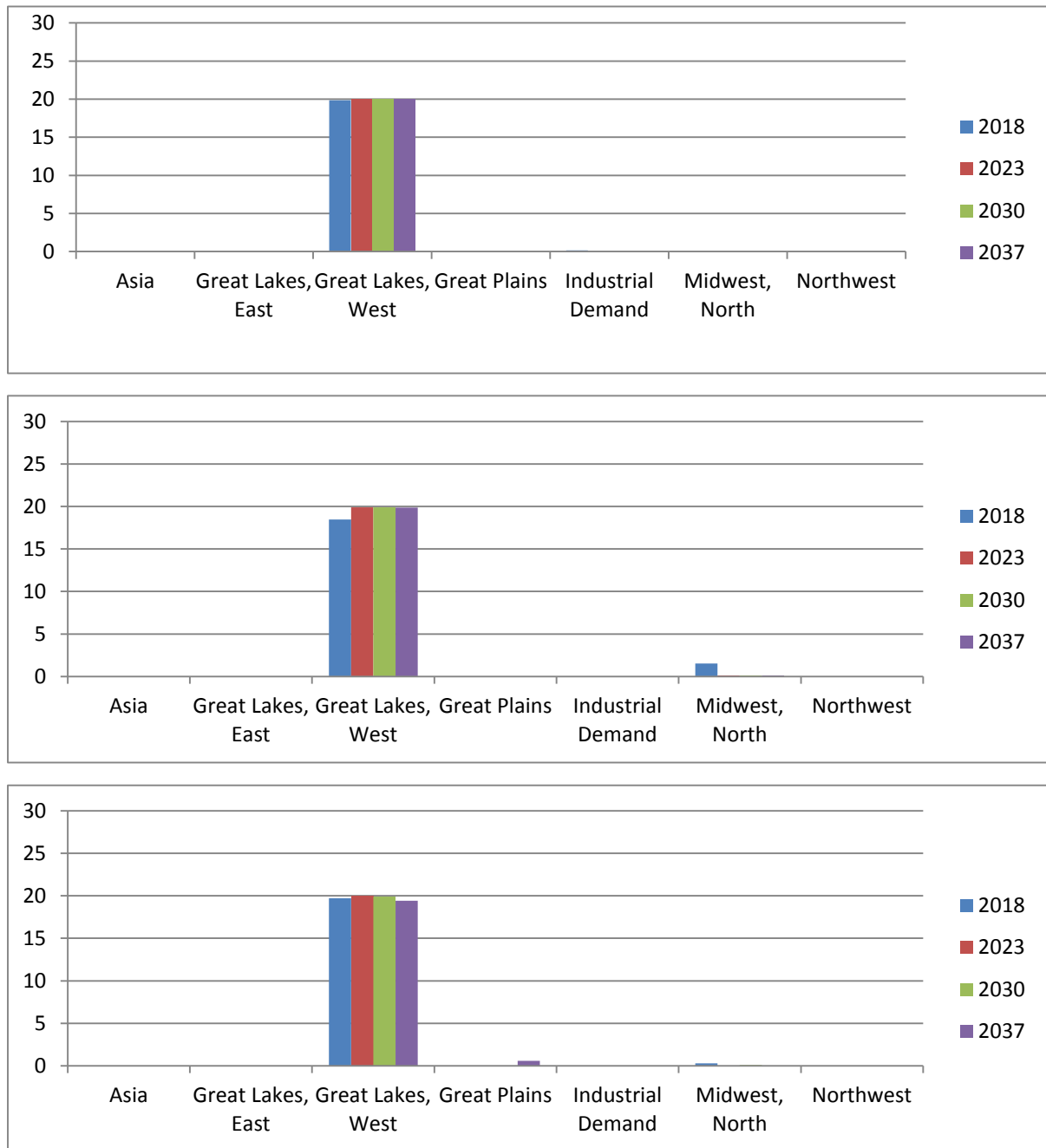


Figure 8-12. Distribution of Tongue River Coal for Southern Alternatives, Low Production: Zero (top chart), Medium (middle chart), and High Growth (bottom chart) in million tons/year (scenarios 12, 13, and 14)

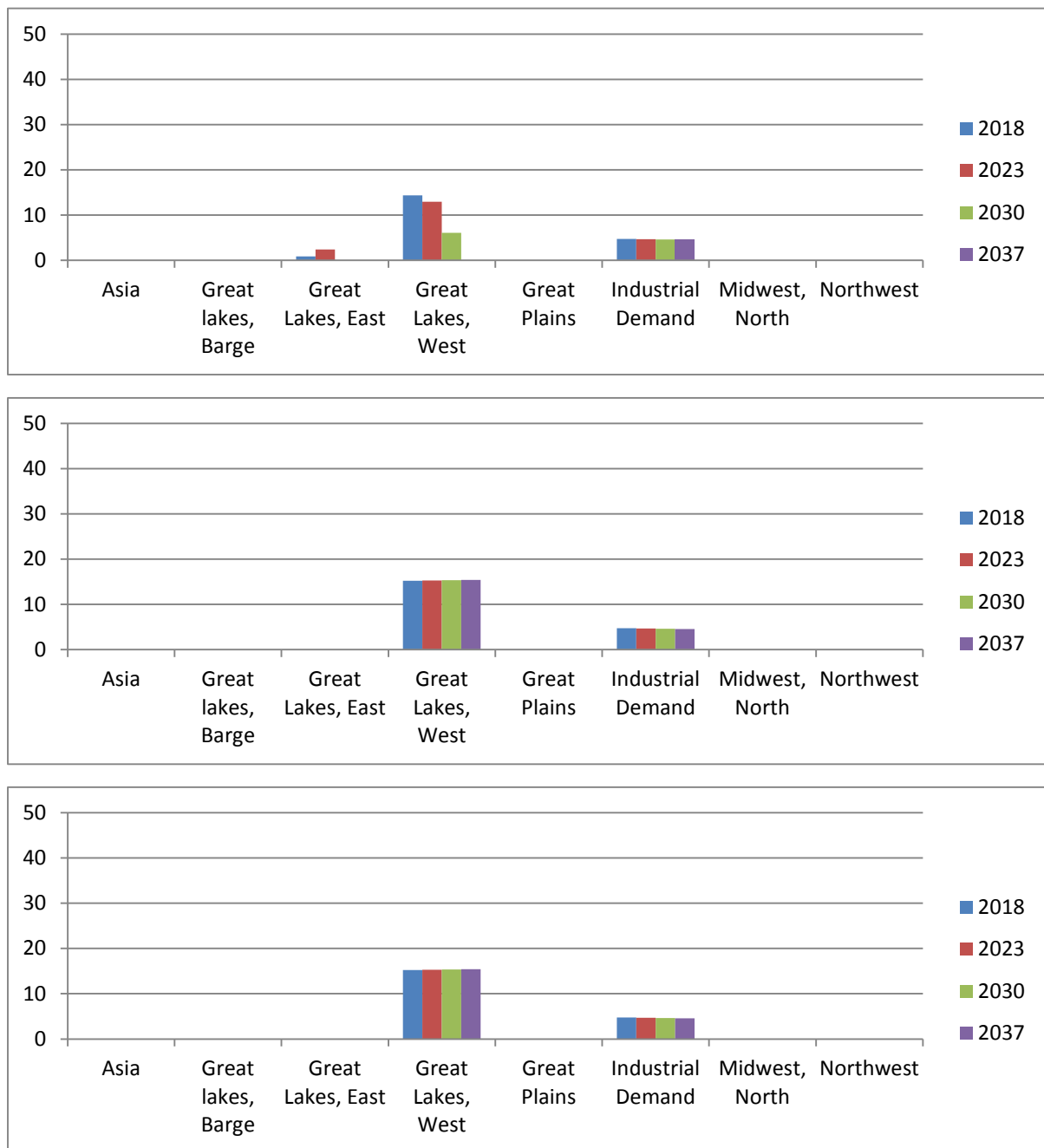


Figure 8-13. Distribution of Tongue River Coal for Southern Alternatives, Medium Production: Zero (top chart), Medium (middle chart), and High Growth (bottom chart) in million tons/year (scenarios 15, 16, and 17)

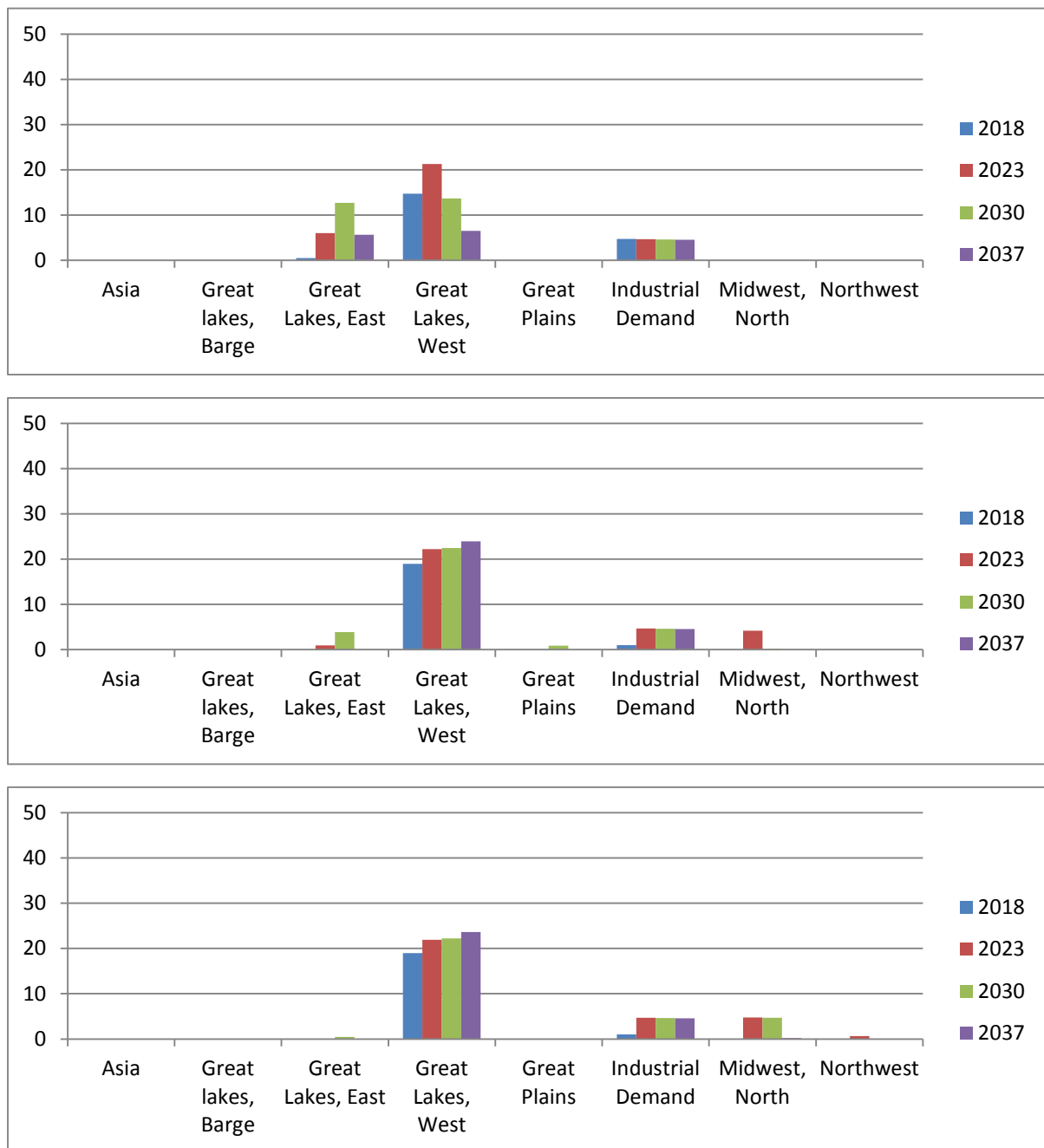
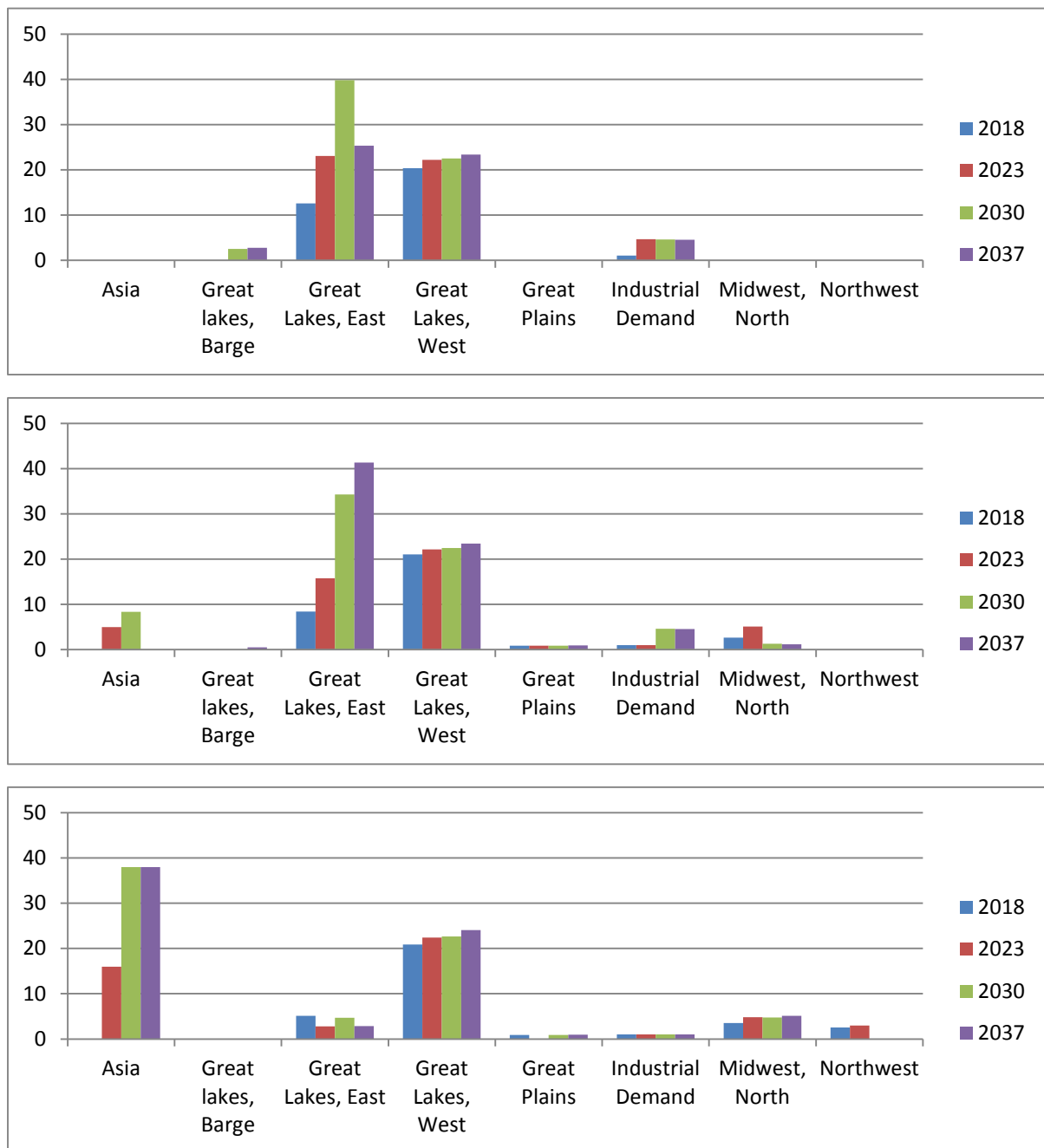


Figure 8-14. Distribution of Tongue River Coal for Southern Alternatives, High Production: Zero (top chart), Medium (middle chart), and High Growth (bottom chart) in million tons/year (scenarios 18, 19, and 20)



8.4.2 Exports

OEA concluded that average annual exports of Tongue River coal would be between 0 and 40% of total production, depending on the production level and the level of export capacity. On an annual basis, exports between 0 and 53% of Tongue River coal production in a single

year (i.e., without any averaging) would be expected. The 2018 to 2037 average across all 21 primary sensitivity scenarios shows an estimated 4% of Tongue River coal would be exported. The portion exported on average would be low across the scenarios because other Powder River Basin coal with higher heat content would be more competitive for export. However, coal distribution would be sensitive to terminal capacity growth for export terminals and the maximum amount and type of Tongue River coal production.

Under the two scenarios with high Tongue River coal production and high terminal capacity growth, (scenarios 11 and 20), the share of yearly Tongue River export would increase to 38 and 53%, respectively (19 million of 50 million tons per year [scenario 11], and 38 million tons of 72 million tons per year [scenario 20]). Scenario 20 assumes that, under the southern alternatives, exports would include the high-heat content coal from the Canyon Creek deposit. In many other scenarios (scenarios 3, 4, 5, 6, 9, 12, 13, 14, 15, 16, 17, 18, 21, 22, and 23), the export percentage of Tongue River coal would be zero. OEA's conclusions regarding the range expected are based on the range in the 21 primary sensitivity scenarios, and are bolstered by the uncertainties facing coal sellers that cannot be fully captured in a modeling framework. For example, OEA's forecasts assumed competitive economics and certainty within each scenario. Note, however, that Arch Coal is the co-developer of the TRRC railroad, the Otter Creek Mine, and one of the export terminals, the Millennium Bulk Terminal. Hence, Arch Coal might choose to export rather than sell domestically when there are opportunities to maximize profits over the suite of assets that include mines, railroads, and export terminals.

This chapter also reports the modeling results according to the scenarios described in Chapter 7, *Scenarios*. Figures 8-15 through 8-20 illustrate the possible distribution of Tongue River coal under different scenarios.

- **Figure 8-15.** This figure shows where coal would flow under the No-Action Alternative with zero export terminal growth (scenario 1). Exports of Powder River Basin coal to the Pacific Basin would be limited to 8 million tons based on existing export terminal capacity. Although Pacific Northwest terminal capacity would be fully used, exports would not exceed historical levels because there would be no increase in terminal capacity.
- **Figure 8-16.** This figure shows where coal would flow assuming the northern alternatives, low production, and zero growth scenario (scenario 3). Tongue River coal would be sold domestically to the Midwest.
- **Figure 8-17.** This figure shows the difference between the yearly average coal distribution patterns shown in Figures 8-15 and 8-16, or between a No-Action Alternative scenario and a low-growth scenario (scenarios 1 and 3). Tongue River coal shipments to the Midwest would primarily displace other Powder River Basin coal shipments to that region.
- **Figure 8-18.** This figure shows where coal would flow under the No-Action Alternative with high export terminal growth (scenario 2). Powder River Basin coal shipments

would increase and the increased Pacific Northwest terminal capacity would be fully used.

- **Figure 8-19.** This figure shows where coal would flow assuming the southern alternatives, high production, and high growth scenario (scenario 20). Tongue River coal would be exported to the Pacific Basin (40%), and delivered domestically (60%). The export figure of 40% is a yearly average across the 2018 to 2037 timeframe, whereas the previously mentioned maximum export figure of 53% is the maximum for a single year 2030 and 2037.
- **Figure 8-20.** This figure shows the difference between the coal distribution shown in Figures 8-18 and 8-19, or between the No-Action Alternative (scenario 2) and a high-production, high-growth scenario (scenario 20). Tongue River coal would be distributed to both export terminals and domestically, and other Powder River Basin coal exports and domestic sales would be displaced.

Figure 8-15. Coal Production and Regional Distribution, 2018 to 2037 Yearly Average Scenario 1: No-Action Alternative with Zero Growth

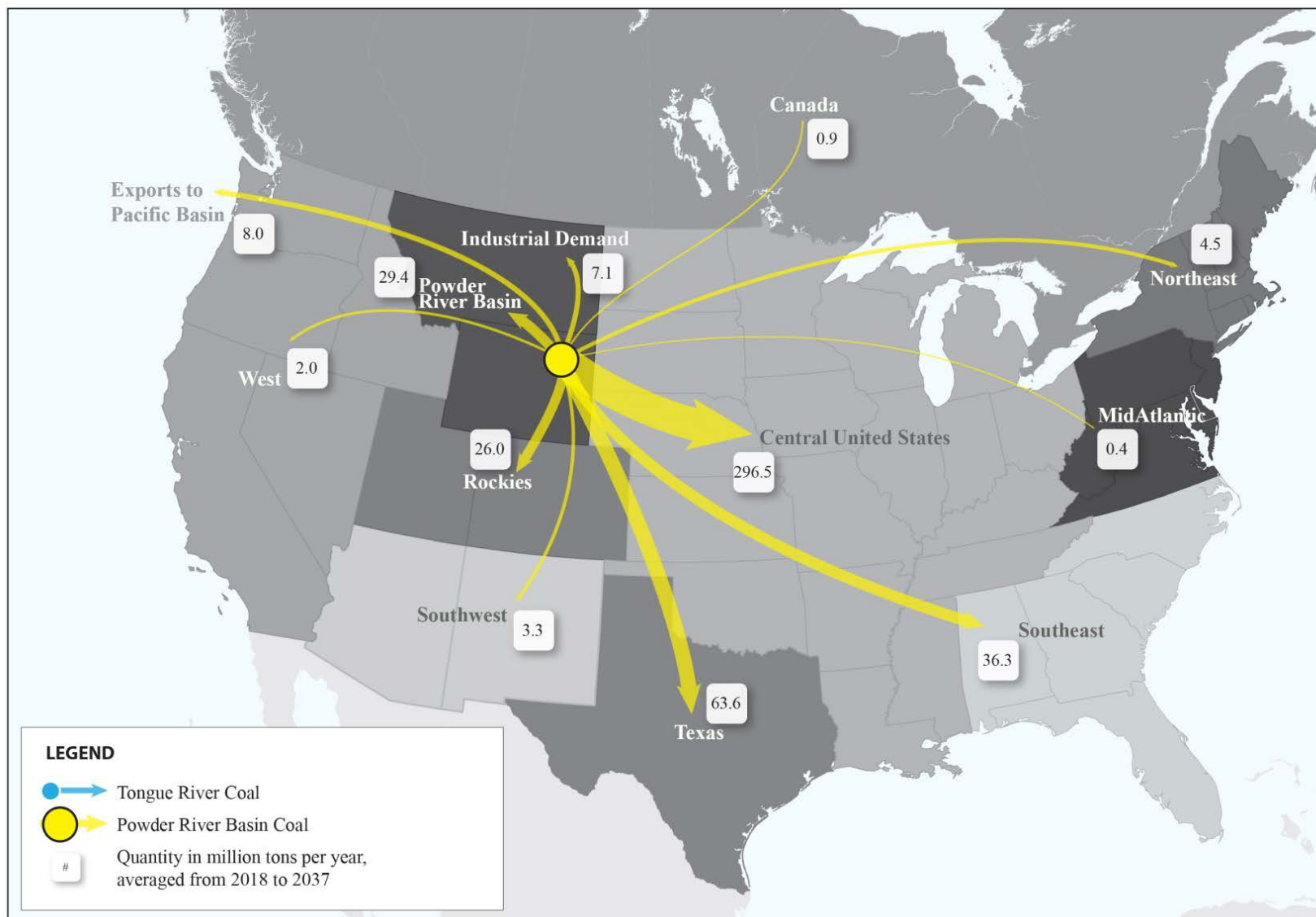


Figure 8-16. Coal Production and Regional Distribution, 2018 to 2037 Yearly Average, Scenario 3: Proposed Action (Northern Alternatives, Low Production, Zero Growth)

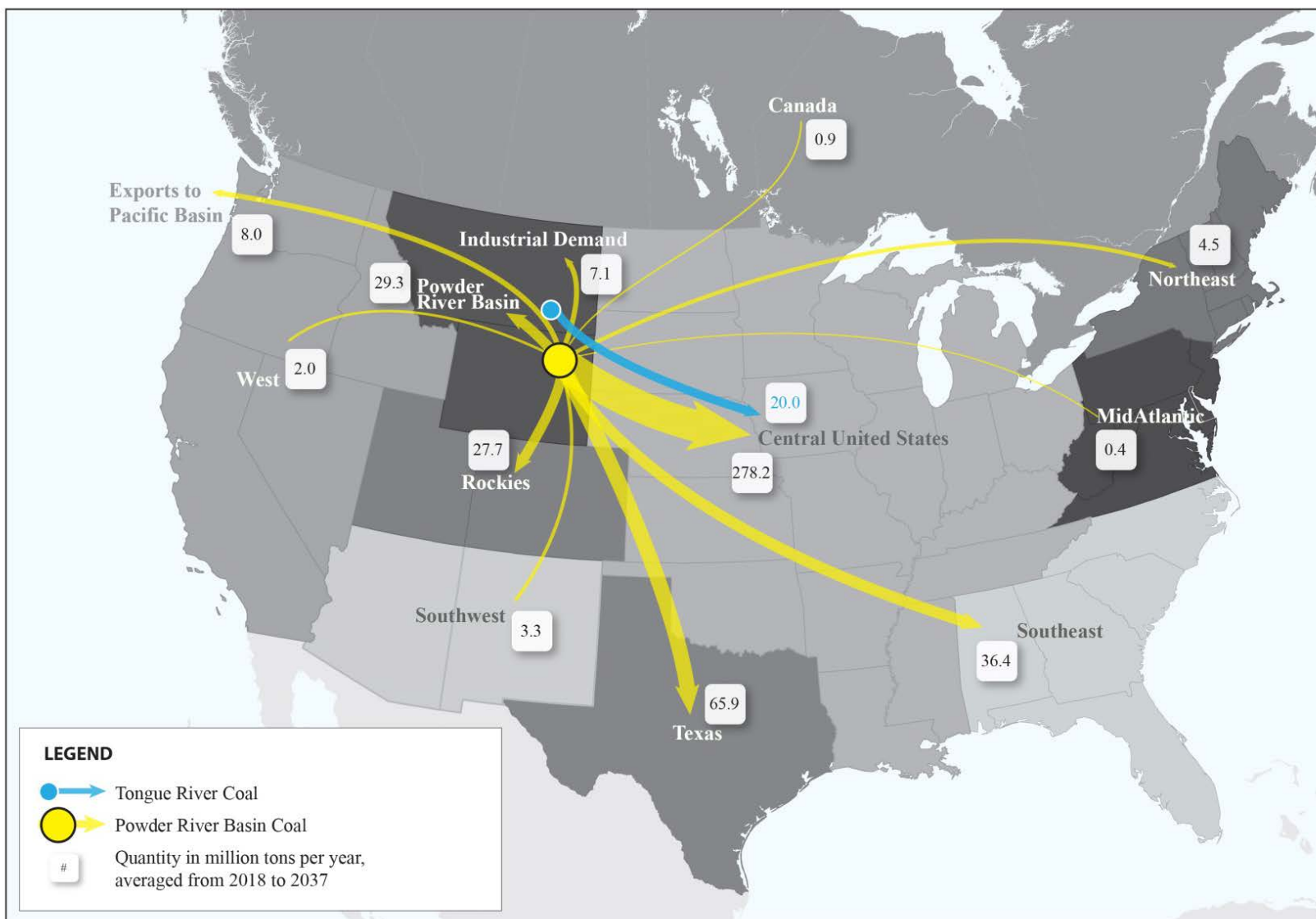


Figure 8-17. Coal Production and Regional Distribution, 2018 to 2037 Yearly Average, Delta between Scenarios 1 and 3

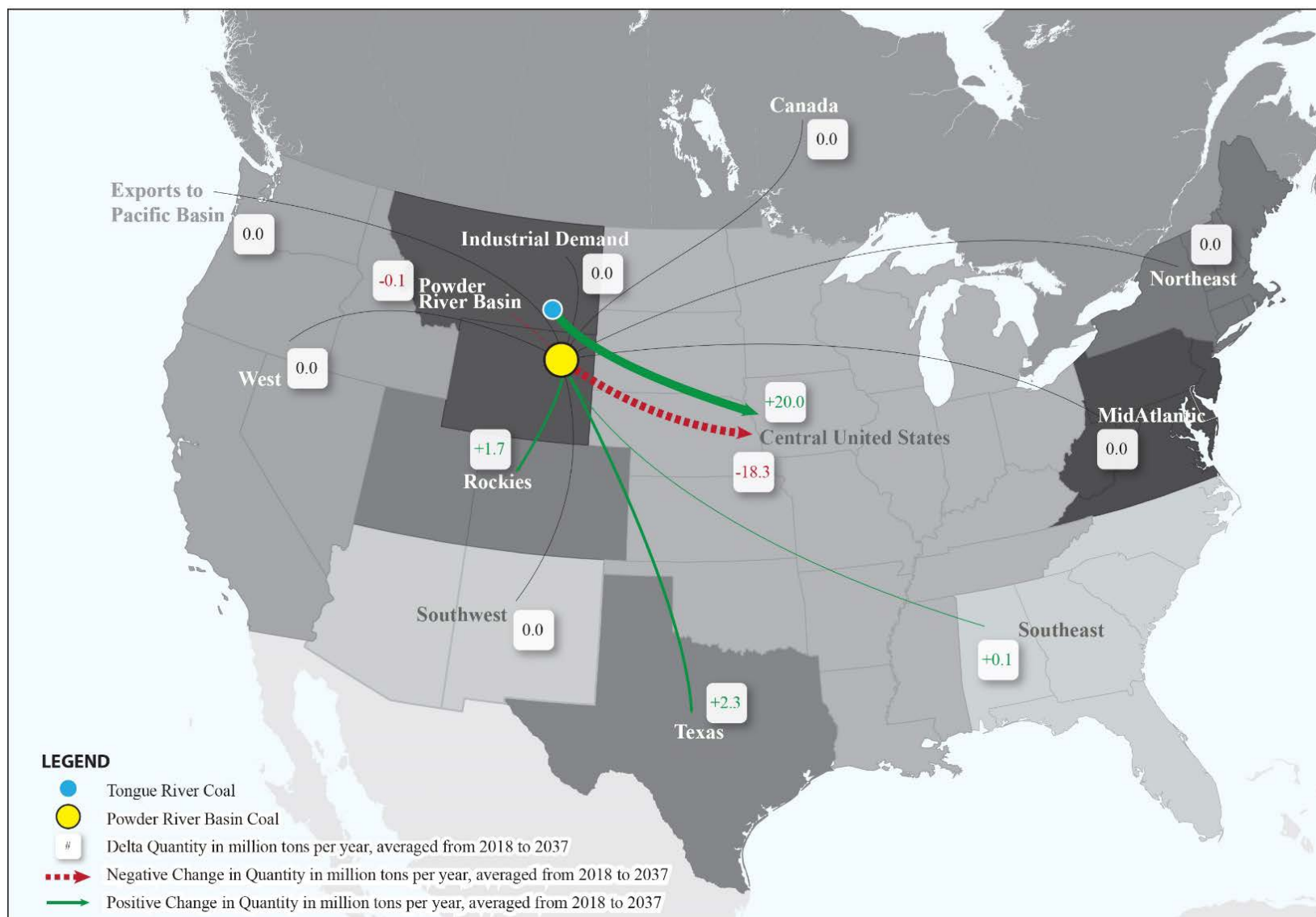


Figure 8-18. Coal Production and Regional Distribution, 2018 to 2037 Yearly Average, Scenario 2: No-Action Alternative with High Growth

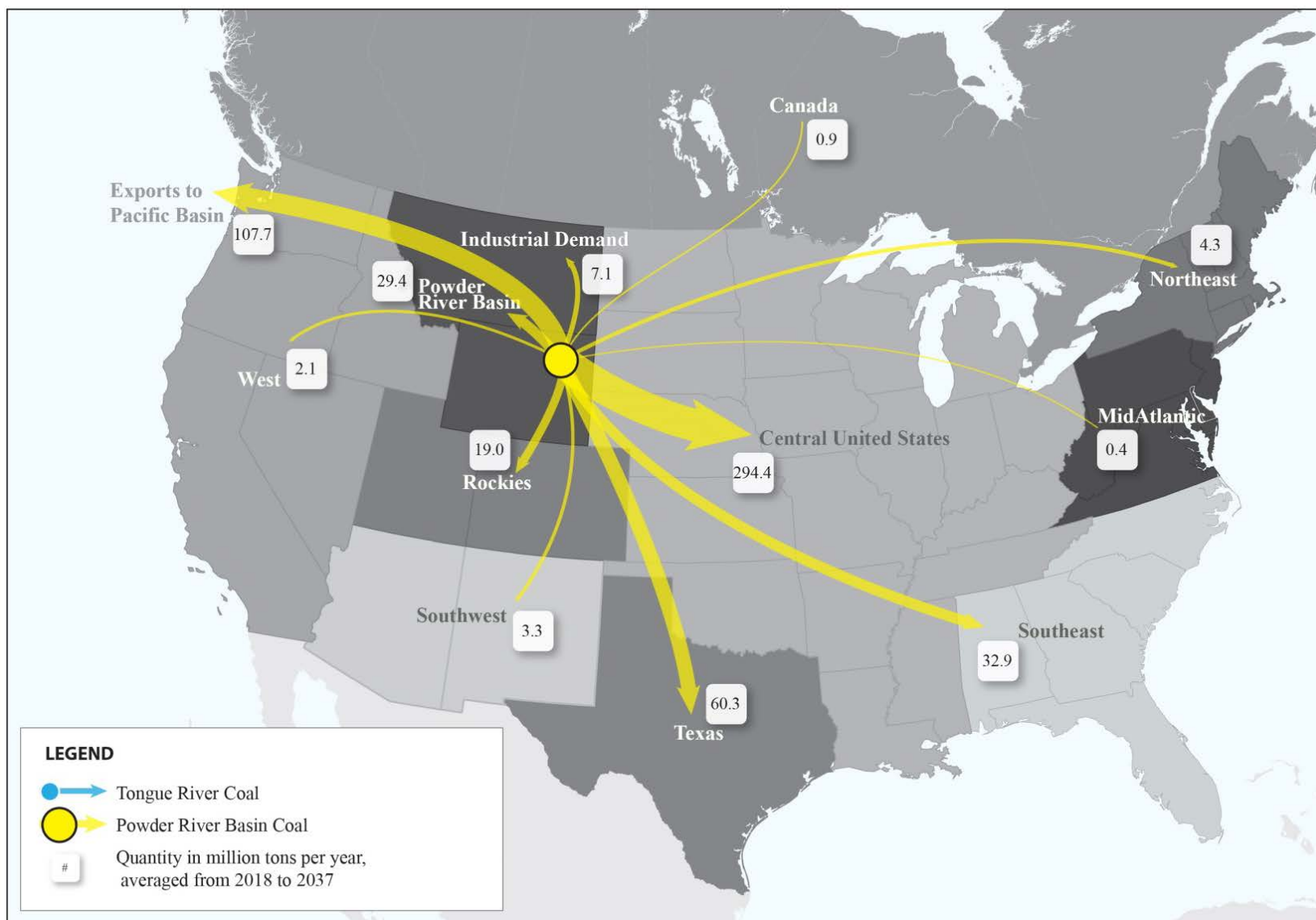


Figure 8-19. Coal Production and Regional Deliveries, 2018 to 2037 Yearly Average, Scenario 20: Proposed Action (Southern Alternatives, High Production, High Growth)

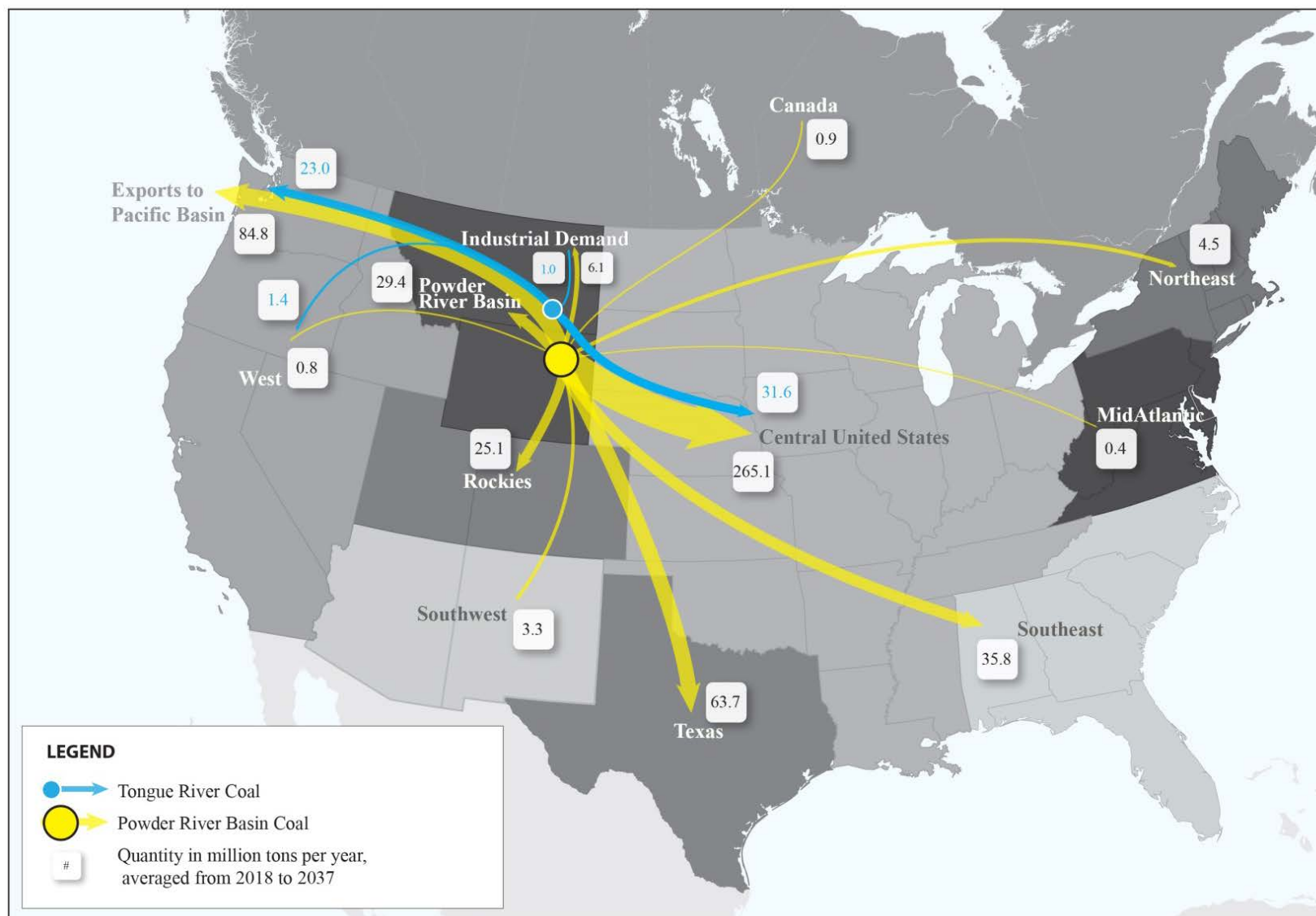
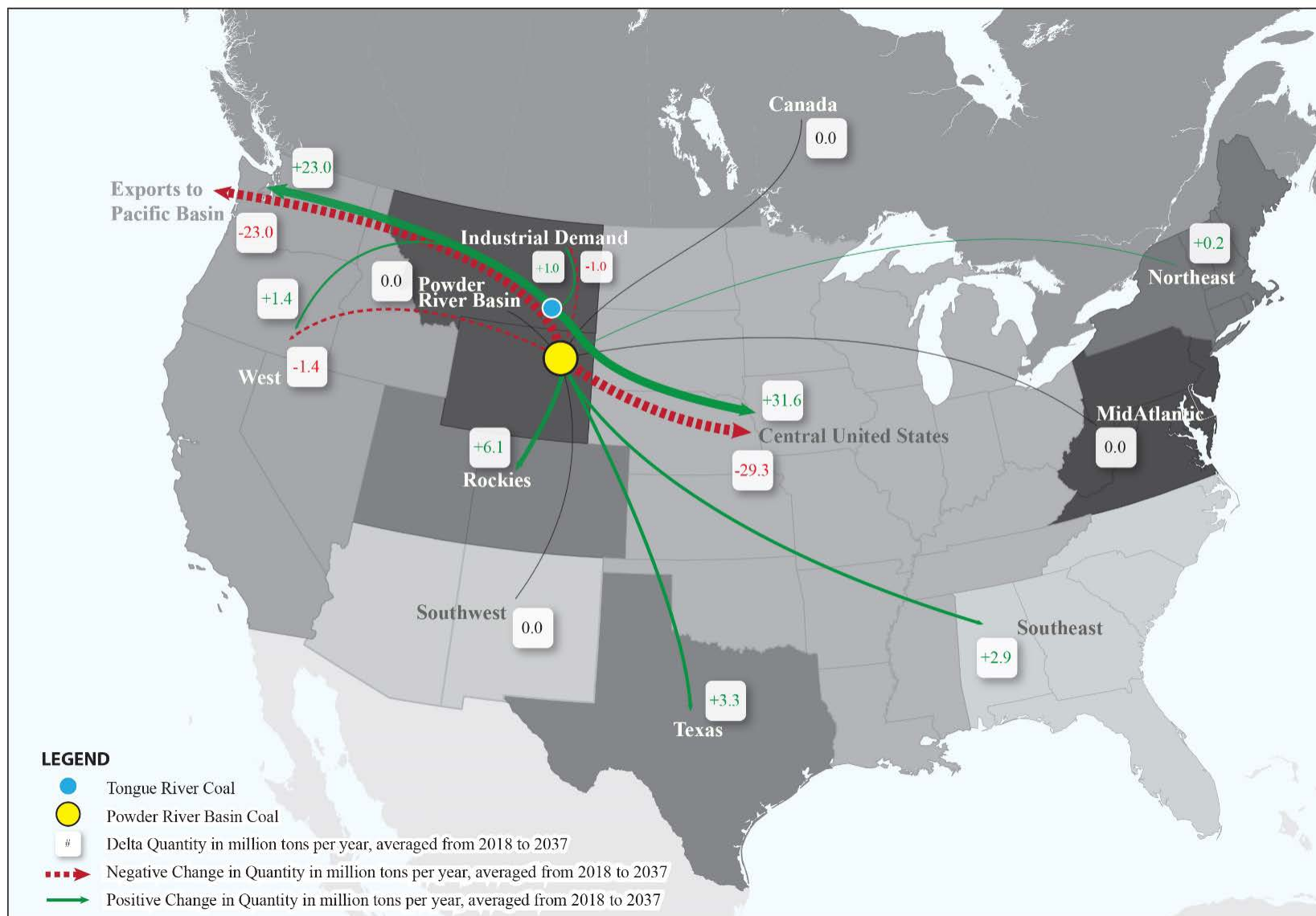
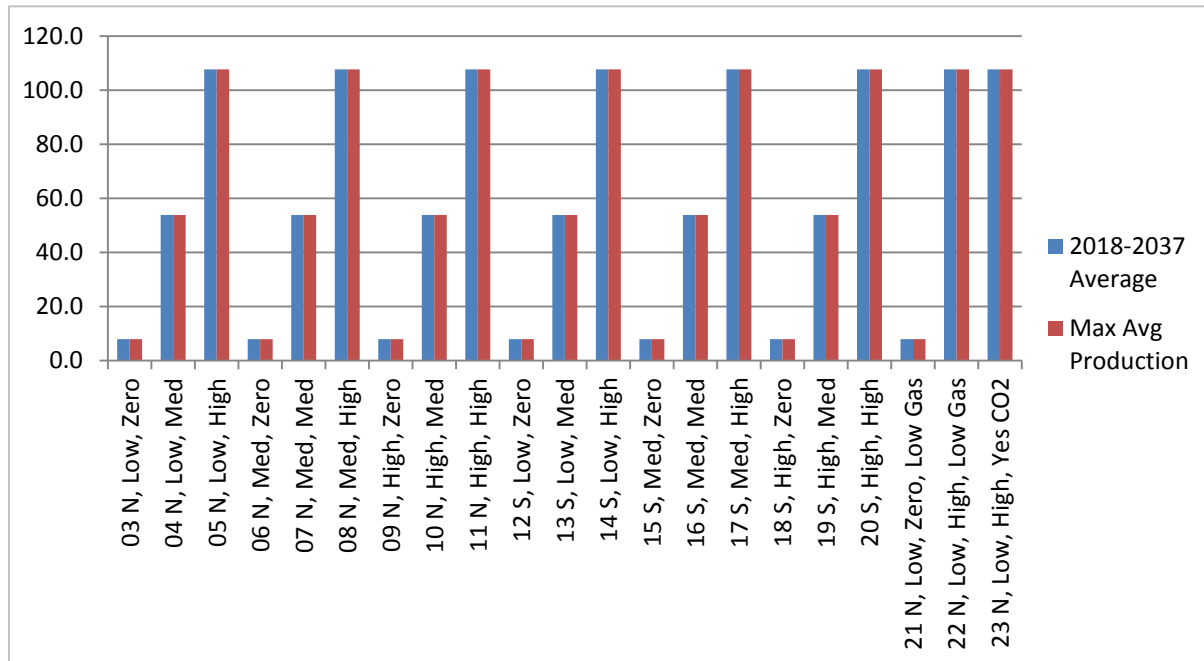


Figure 8-20. Coal Production and Regional Deliveries, 2018 to 2037 Yearly Average, Delta between Scenarios 2 and 20



The increase in export terminal capacity for Powder River Basin coal shipments to Asia would significantly increase the market for Powder River Basin coal (Figure 8-21).

Figure 8-21. Powder River Basin Coal Exports to Asia (million tons/year)



The two scenarios with the highest levels of Tongue River coal deliveries to the Pacific Northwest for exports to Asia are the northern alternatives with high production and high terminal capacity growth (scenario 11) and the southern alternatives with high maximum production and high terminal capacity growth (scenario 20). However, the corresponding scenario under the No-Action Alternative with high terminal capacity growth (scenario 2) would result in essentially the same amount of rail traffic flowing from the Powder River Basin to the Pacific Northwest, because the modeling shows that the export terminals would be fully used, both with and without the proposed rail line. Therefore, construction of the Tongue River Railroad would not affect the level of coal train traffic to the Pacific Northwest.

The maximum export capacity for each of the Pacific Northwest terminal capacity growth cases is reached under all 21 primary sensitivity scenarios studied by OEA. In some scenarios (e.g., scenarios 11 and 20), Tongue River coal would displace other Powder River Basin coal for shipments to the Pacific Northwest. Therefore, the number of trains per day carrying coal from the Powder River Basin to the Pacific Northwest export terminals would be the same under the No-Action Alternative and proposed rail line alternatives, with the exception of the rail line segments near the Tongue River mines and the rest of the Powder River Basin as described in Chapter 9, *Rail Transportation Routes*.

Tongue River coal exports would also be economically viable in cases with low natural gas prices or with CO₂ emission regulations.³ Asia has a strong demand for Powder River Basin coal. If the proposed rail line is not approved and built, other Powder River Basin mines would respond to market demand by increasing exports to Asia, assuming that additional export capacity is constructed; the proposed rail line is not a necessary development for increased exports to the Pacific Basin if additional export capacity is available. Thus, if export capacity were built, the export capacity would be fully used whether or not the proposed rail line is authorized and constructed. If no new coal export capacity were added, but the railroad is authorized and built, Tongue River coal would still be economically viable and sold domestically. The coal would be competitive given its low production costs and location advantages for some markets. Overall, from 2018 to 2037, Powder River Basin coal production would average 485, 527, and 573 million tons per year, under the cases of zero, medium, and high terminal capacity growth, respectively (scenarios 1, 2, and 25). Because the Asian market favors the economical Powder River Basin coal, production levels would be much more sensitive to export capacity available than to Tongue River coal production levels.

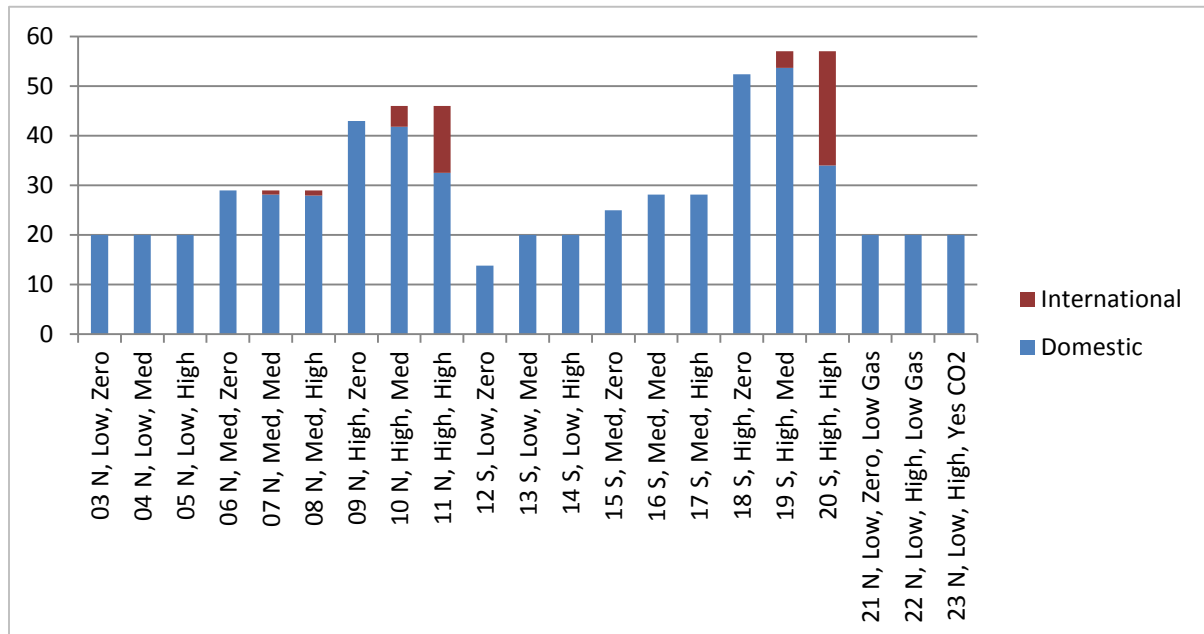
Tongue River coal would be exported in only six of 21 primary sensitivity scenarios: the northern alternatives with medium or high coal production, and medium or high terminal capacity growth (scenarios 7, 8, 10, and 11) and the southern alternatives with high coal production and medium or high terminal capacity growth (scenarios 19 and 20). On average, across the 21 primary sensitivity scenarios and from 2018 to 2037, 4% of Tongue River coal would be exported. Only in scenarios with high production and high terminal capacity growth (scenarios 11 and 20) would exports exceed 10% of production. One caveat worth mentioning is that of the 18 non-sensitivity scenarios (i.e., base natural gas prices, and no CO₂ costs), six have assumed zero terminal capacity growth, and therefore little export potential. On average, in the remaining 12 cases, 7.6% of Tongue River coal would be exported. In the six high terminal capacity growth cases, on average 12.2% of Tongue River coal would be exported. At higher levels of maximum production and export terminal capacity, larger quantities of Tongue River coal would be exported. The highest amount of coal exported would be 40% for the southern alternatives, high production, high growth scenario (scenario 20) (Figure 8-22).

Tongue River coal exports may be affected by circumstances and by economic considerations that cannot be fully reflected in the scenarios. One circumstance is the uncertainty about contracting options with domestic and export buyers. For example, Arch Coal is the owner of the proposed Otter Creek Mine, a one-third owner of the Tongue River Railroad, and partial owner of one of the proposed coal export facilities. Accordingly, Arch Coal could decide to maximize the value of its assets by exporting its Tongue River coal over other Powder River Basin coal, even if long-term competitive economics and modeling alone

³ President Obama announced his climate change action plan on June 25, 2013. This plan would affect U.S. CO₂ emissions and will increase the sensitivity of the market. However, prospects for CO₂ emissions control in the Pacific Basin are not immediate, and were not analyzed in the model.

indicate that Tongue River coal would most likely meet domestic demand if export capacity in the Pacific Northwest increases.

Figure 8-22. Tongue River Coal Deliveries, Domestic and International, Averaged 2018 to 2037 (million tons/year)



8.4.3 Rail Traffic

If the Board approves construction of the Tongue River Railroad, train traffic would increase on rail lines outside of the immediate project area. If a northern alternative is approved, Tongue River coal production would add between 7.4 train trips per day (eastbound and westbound) to 18.6 train trips per day (eastbound and westbound). If a southern alternative were approved, the increase would range from 1.7 train trips per day (eastbound and westbound) to 26.7 train trips per day (eastbound and westbound) (Table 8-1). This train traffic would be additional to traffic under the No-Action Alternative primarily in the immediate area around the Tongue River Railroad, as much of the Tongue River coal would displace coal produced in other parts of the Powder River Basin. Chapter 9, *Rail Transportation Routes* discusses rail traffic at a more detailed level. The following rail traffic discussion addresses the issues of displacement of other Powder River Basin coal train traffic with the addition of Tongue River coal train traffic.

OEA's modeling shows that the additional Tongue River coal trains that would result from the proposed rail line would displace some of the current Powder River Basin rail traffic. In the No-Action Alternative scenarios, the number of trains leaving or entering the Powder River Basin would range from 148.5 to 212.2 trains per day (Table 8-2). After displacement is considered, Tongue River coal production would increase train trips originating from or returning to the Powder River Basin by 0 to 11.4 trains per day (Table 8-3). The incremental addition of train traffic from the proposed rail line would be small when compared to the

total train traffic in the basin, especially considering that not all of the incremental train traffic would be traveling the same route.

Table 8-1. Tongue River Coal Trains per Day by Scenario and Year

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
1	No-Action Alternative	N/A	Zero	No TRR, Zero growth	N/A	N/A	N/A	N/A
2	No-Action Alternative	N/A	High	No TRR, High growth	N/A	N/A	N/A	N/A
3	Northern	Low	Zero	N, Low, Zero	7.4	7.4	7.4	7.4
4	Northern	Low	Medium	N, Low, Med	7.4	7.4	7.4	7.4
5	Northern	Low	High	N, Low, High	7.4	7.4	7.4	7.4
6	Northern	Medium	Zero	N, Medium, Zero	7.4	11.9	11.9	11.8
7	Northern	Medium	Medium	N, Medium, Medium	7.4	11.9	11.9	11.9
8	Northern	Medium	High	N, Medium, High	7.4	11.9	11.9	11.9
9	Northern	High	Zero	N, High, Zero	12.6	18.6	18.6	14.1
10	Northern	High	Medium	N, High, Medium	12.6	18.6	18.6	18.6
11	Northern	High	High	N, High, High	12.6	18.6	18.6	18.6
12	Southern	Low	Zero	S, Low, Zero	7.4	7.4	4.0	1.7
13	Southern	Low	Medium	S, Low, Med	7.4	7.4	7.4	7.4
14	Southern	Low	High	S, Low, High	7.4	7.4	7.4	7.4
15	Southern	Medium	Zero	S, Medium, Zero	7.4	11.9	11.5	6.2
16	Southern	Medium	Medium	S, Medium, Med	7.4	11.9	11.9	10.6
17	Southern	Medium	High	S, Medium, High	7.4	11.9	11.9	10.6
18	Southern	High	Zero	S, High, Zero	12.6	18.6	25.8	20.8
19	Southern	High	Medium	S, High, Med	12.6	18.6	26.7	26.7
20	Southern	High	High	S, High, High	12.6	18.6	26.7	26.7
21	Northern	Low	Zero	N, Low, Zero, Low Gas	7.4	7.4	7.4	7.4
22	Northern	Low	High	N, Low, High, Low Gas	7.4	7.4	7.4	7.4
23	Northern	Low	High	N, Low, High, Yes CO ₂	7.4	7.4	7.4	7.4
24	No-Action Alternative	N/A	High	No TRR, High, Yes CO ₂	N/A	N/A	N/A	N/A
25	No-Action Alternative	N/A	Medium	No TRR, Medium	N/A	N/A	N/A	N/A
26	No-Action Alternative	N/A	Zero	No TRR, Zero, Low Gas	N/A	N/A	N/A	N/A
27	No-Action Alternative	N/A	High	No TRR, High, Low Gas	N/A	N/A	N/A	N/A

Table 8-2. Total Coal Trains Leaving or Entering the Powder River Basin per Day

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
1	No-Action Alternative	N/A	Zero	No TRR, Zero	171.1	179.1	167.1	170.7
2	No-Action Alternative	N/A	High	No TRR, High	184.9	210.0	205.7	212.2
3	Northern	Low	Zero	N, Low, Zero	172.2	179.7	172.5	172.1
4	Northern	Low	Medium	N, Low, Med	179.7	198.8	186.3	190.7
5	Northern	Low	High	N, Low, High	187.8	218.2	206.9	212.3
6	Northern	Medium	Zero	N, Medium, Zero	172.4	180.0	174.4	173.3
7	Northern	Medium	Medium	N, Medium, Medium	180.1	199.3	187.5	191.3
8	Northern	Medium	High	N, Medium, High	187.7	219.3	207.4	212.8
9	Northern	High	Zero	N, High, Zero	173.2	179.9	175.3	173.3
10	Northern	High	Medium	N, High, Medium	181.7	200.2	190.0	192.0
11	Northern	High	High	N, High, High	191.0	220.7	208.3	212.9
12	Southern	Low	Zero	S, Low, Zero	172.2	179.8	170.5	171.1
13	Southern	Low	Medium	S, Low, Med	179.8	199.0	186.6	190.8
14	Southern	Low	High	S, Low, High	187.8	218.3	206.9	212.4
15	Southern	Medium	Zero	S, Medium, Zero	172.3	179.7	174.2	172.1
16	Southern	Medium	Medium	S, Medium, Med	180.1	199.3	187.3	191.2
17	Southern	Medium	High	S, Medium, High	187.7	219.3	207.1	212.6
18	Southern	High	Zero	S, High, Zero	173.1	179.7	175.3	173.2
19	Southern	High	Medium	S, High, Med	181.9	200.0	194.7	193.5
20	Southern	High	High	S, High, High	190.9	221.3	208.8	213.6
21	Northern	Low	Zero	N, Low, Zero, Low Gas	149.6	166.9	174.3	171.6
22	Northern	Low	High	N, Low, High, Low Gas	168.6	207.3	206.6	211.8
23	Northern	Low	High	N, Low, High, Yes CO ₂	184.4	205.5	186.2	180.2
24	No-Action Alternative	N/A	High	No TRR, High, Yes CO ₂	181.9	203.5	186.0	179.9
25	No-Action Alternative	N/A	Medium	No TRR, Medium	178.4	197.9	185.6	190.1
26	No-Action Alternative	N/A	Zero	No TRR, Zero, Low Gas	148.5	166.3	170.7	170.3
27	No-Action Alternative	N/A	High	No TRR, High, Low Gas	167.3	205.6	206.0	211.7

Table 8-3. Change in the Number of Coal Trains Leaving or Entering the Powder River Basin per Day Relative to No-Action Alternative

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
3	Northern	Low	Zero	N, Low, Zero	1.1	0.6	5.4	1.3
4	Northern	Low	Medium	N, Low, Med	1.3	0.9	0.7	0.6
5	Northern	Low	High	N, Low, High	2.9	8.2	1.2	0.2
6	Northern	Medium	Zero	N, Medium, Zero	1.3	0.9	7.3	2.5
7	Northern	Medium	Medium	N, Medium, Medium	1.8	1.5	1.8	1.2
8	Northern	Medium	High	N, Medium, High	2.8	9.3	1.7	0.6
9	Northern	High	Zero	N, High, Zero	2.0	0.8	8.2	2.5
10	Northern	High	Medium	N, High, Medium	3.3	2.3	4.4	1.9
11	Northern	High	High	N, High, High	6.1	10.7	2.6	0.8
12	Southern	Low	Zero	S, Low, Zero	1.1	0.7	3.4	0.3
13	Southern	Low	Medium	S, Low, Med	1.4	1.1	0.9	0.7
14	Southern	Low	High	S, Low, High	2.9	8.4	1.3	0.3
15	Southern	Medium	Zero	S, Medium, Zero	1.2	0.6	7.1	1.4
16	Southern	Medium	Medium	S, Medium, Med	1.7	1.4	1.7	1.1
17	Southern	Medium	High	S, Medium, High	2.8	9.3	1.4	0.4
18	Southern	High	Zero	S, High, Zero	2.0	0.6	8.1	2.4
19	Southern	High	Medium	S, High, Med	3.5	2.1	9.0	3.4
20	Southern	High	High	S, High, High	6.0	11.4	3.2	1.5
21	Northern	Low	Zero	N, Low, Zero, Low Gas	1.1	0.5	3.5	1.3
22	Northern	Low	High	N, Low, High, Low Gas	1.3	1.7	0.5	0.0
23	Northern	Low	High	N, Low, High, Yes CO2	2.5	2.0	0.2	0.3

8.5 Model Results by Scenarios

This section presents the modeling results per each scenario starting with the No-Action Alternative scenarios followed by the proposed rail line alternatives.

8.5.1 No-Action Alternative

Under the No-Action Alternative, the Board would not license construction and operation of the Tongue River Railroad. For the purposes of comparing the No-Action Alternative to the action alternatives, OEA identified six scenarios for study for the following reasons.

- Construction and expansion of the export terminals would affect total Powder River Basin coal production, including Tongue River coal production.

- Only some (or none) of the export terminals may be built.
- The export terminal capacity is held constant between Action and No-Action Alternative scenarios. This allows the effects related to Tongue River coal production and transport to be treated in isolation across all scenarios. In other words, the only variable that is changing between the Action and No-Action scenarios is the development, construction, and operation of the Tongue River Railroad. Changes in coal production, consumption, or export resulting from export terminal development or coal production levels that could confound the effect of the proposed rail line are held constant between the proposed rail line and No-Action scenario pairs.

These three No-Action Alternative scenarios assume no Tongue River coal production with zero, medium, and high terminal growth capacity. Three additional No-Action Alternative scenarios are used to compare these results with natural gas and CO₂ emission price sensitivities. The latter three No-Action Alternative scenarios are as follows.

- No Tongue River coal, zero growth, and low natural gas prices.
- No Tongue River coal, high growth, and low natural gas prices.
- No Tongue River coal, high growth, and a price on CO₂.

The mapping between the proposed rail line scenarios and No-Action Alternative scenarios is presented in Table 8-4.

Table 8-4. Comparison of Coal Production and Export Scenarios and the Corresponding No-Action Alternative Scenario

Tongue River Coal Scenario				Corresponding No-Action Alternative Scenario	
Scenario Number	Alternative	Tongue River Production Level	Export Growth Level	No-Action Alternative	Export Growth Level
3	N	Low	Zero	1	Zero
4	N	Low	Medium	25	Medium
5	N	Low	High	2	High
6	N	Medium	Zero	1	Zero
7	N	Medium	Medium	25	Medium
8	N	Medium	High	2	High
9	N	High	Zero	1	Zero
10	N	High	Medium	25	Medium
11	N	High	High	2	High
12	S	Low	Zero	1	Zero
13	S	Low	Medium	25	Medium
14	S	Low	High	2	High
15	S	Medium	Zero	1	Zero
16	S	Medium	Medium	25	Medium
17	S	Medium	High	2	High
18	S	High	Zero	1	Zero
19	S	High	Medium	25	Medium
20	S	High	High	2	High
21	N	Low	Zero	26, Low Gas	Zero
22	N	Low	High	27, Low Gas	High
23	N	Low	High	24, Yes CO ₂	High

N = northern alternative; S = southern alternative; CO₂ = carbon dioxide

Total Powder River Basin coal production, U.S. coal production, and global coal production across all six No-Action Alternative scenarios are presented in Tables 8-5 through 8-7. In addition, Figures 8-23 through 8-25 summarize the production data found in OEA's modeling by showing the annual production level averaged over 2018 to 2037.

Table 8-5. Powder River Basin Annual Coal Production by Scenario and Year for the No- Action Alternative (million tons per year)

Scenario	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
1	N/A	Zero	No TRR, Zero growth	475.7	497.1	464.9	474.6
25	N/A	Medium	No TRR, Medium Growth	495.2	547.6	514.7	526.7
2	N/A	High	No TRR, High growth	512.7	580.2	568.7	586.1
26	N/A	Zero	No TRR, Zero growth, Low Gas	414.7	462.7	474.6	473.3
27	N/A	High	No TRR, High growth, Low Gas	465.2	568.4	569.6	584.9
24	N/A	High	No TRR, High growth, Yes CO ₂	504.8	562.8	515.7	499.3

Table 8-6. U.S. Annual Coal Production by Scenario and Year for the No-Action Alternative (million tons per year)

Scenario	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
1	N/A	Zero	No TRR, Zero	990	1,022	1,008	1,053
25	N/A	Medium	No TRR, Medium	1,013	1,077	1,061	1,108
2	N/A	High	No TRR, High	1,039	1,135	1,122	1,170
26	N/A	Zero	No TRR, Zero growth, Low Gas	858	947	1,002	1,070
27	N/A	High	No TRR, High, Low Gas	913	1,058	1,115	1,186
24	N/A	High	No TRR, High, Yes CO ₂	1,024	1,076	1,014	985

Table 8-7. Global Annual Coal Production by Scenario and Year for the No-Action Alternative (million tons per year)

Scenario	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
1	N/A	Zero	No TRR, Zero	10,262	10,967	11,699	12,666
25	N/A	Medium	No TRR, Medium	10,262	10,972	11,702	12,669
2	N/A	High	No TRR, High	10,258	10,975	11,708	12,675
26	N/A	Zero	No TRR, Zero, Low Gas	10,126	10,891	11,693	12,683
27	N/A	High	No TRR, High, Low Gas	10,128	10,898	11,701	12,690
24	N/A	High	No TRR, High, Yes CO ₂	10,243	10,917	11,601	12,486

Figure 8-23. Total Powder River Basin Coal Production by No-Action Alternative, Averaged 2018 to 2037 in million tons/year (scenarios 1, 25, 2, 26, 27, 24)

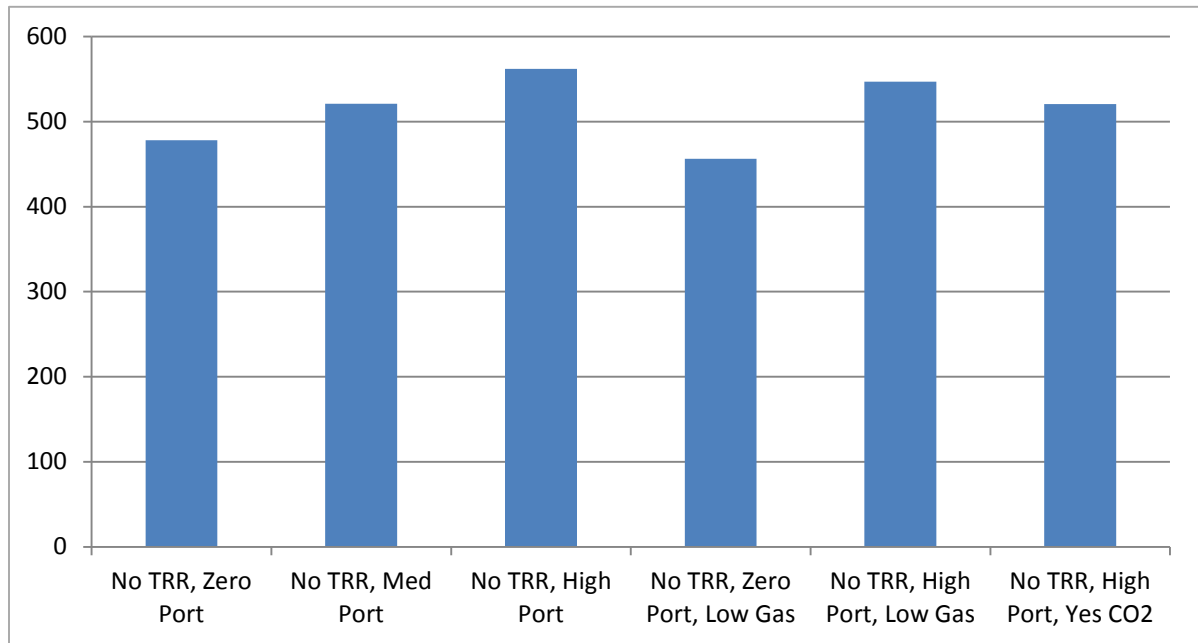


Figure 8-24. Total U.S. Coal Production by No-Action Alternative, Averaged 2018 to 2037 in million tons/year (scenarios 1, 25, 2, 26, 27, 24)

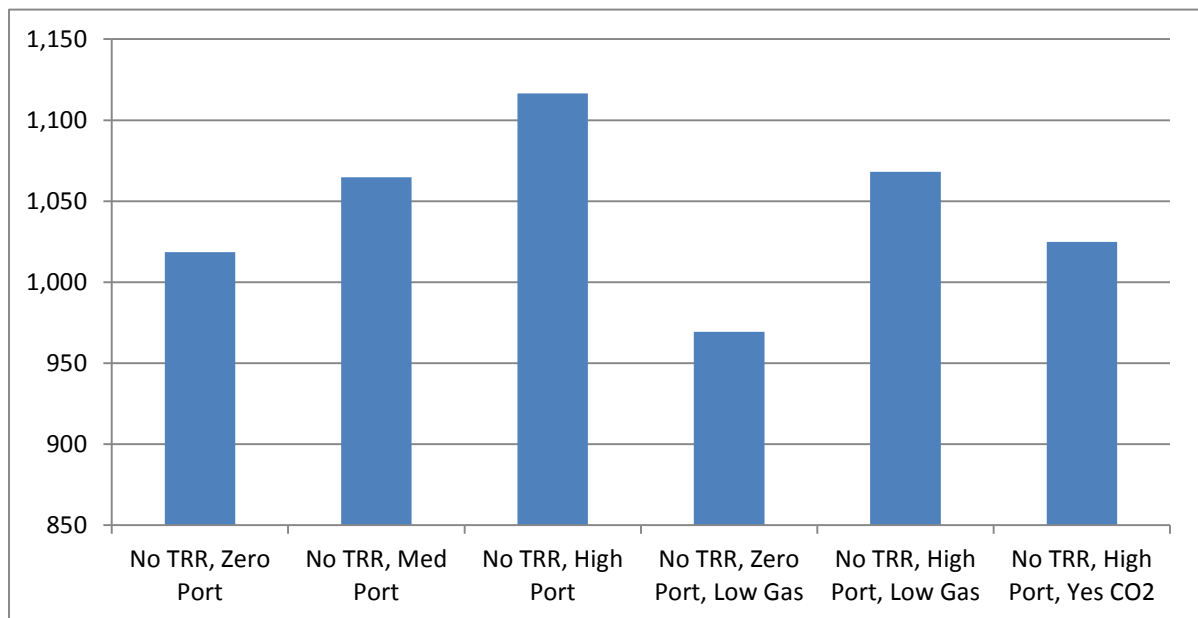
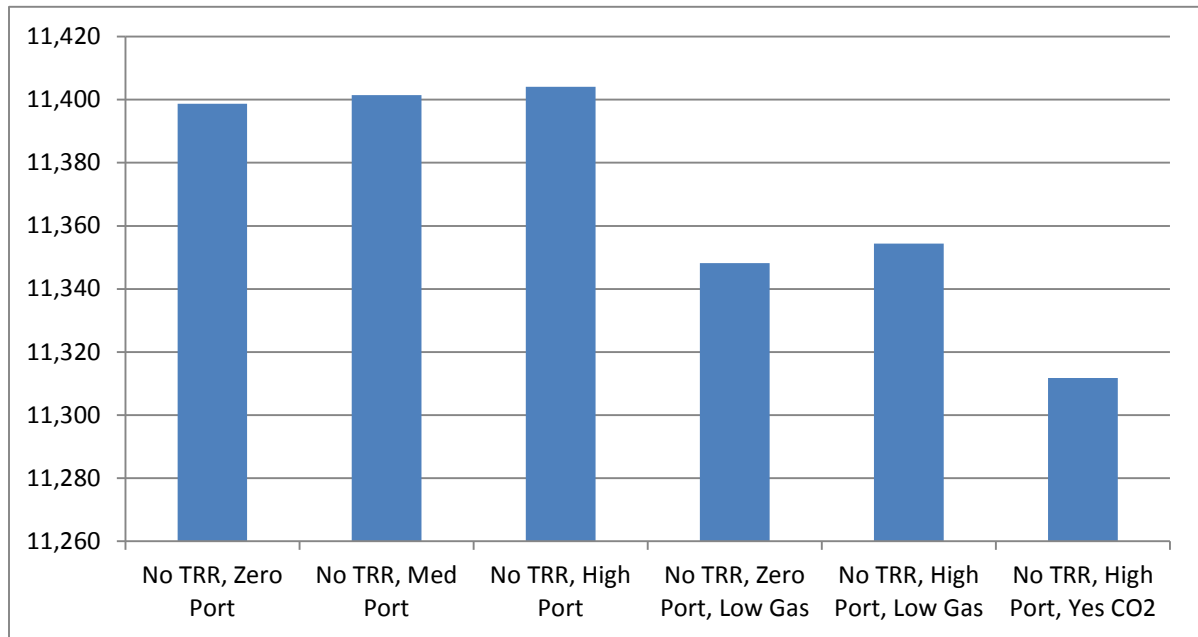


Figure 8-25. Total World Coal Production by No-Action Alternative, averaged 2018 to 2037 in million tons/year (scenarios 1, 25, 2, 26, 27, 24)



Under the No-Action Alternative scenarios, total Powder River Basin coal production and U.S. coal production would increase by about the same amount: 40 to 50 million tons per year from the zero to the medium export growth case and 40 to 50 million tons per year from the medium to the high export growth case. This suggests that the change in the overall U.S. coal production from the increase in export terminal capacity is due to increased Powder River Basin coal production to meet export demand. In other words, development of the proposed rail line is not necessary for Powder River Basin coal to be exported out of the Pacific Northwest. Overall world production levels are significantly less sensitive to increases in domestic export terminal capacity. This is because, as the U.S. export terminal capacities increase, the additional Powder River Basin coal shipped to Asia would displace coal production in China, Indonesia, and Australia, or would be used to meet the expected growing demand for coal in the Pacific Basin. Powder River Basin coal is cost-competitive with coal from China, Indonesia, and Australia because it has lower production costs, which offset the higher transportation costs. In addition, the Powder River Basin coal has a low sulfur content, which makes it more attractive than some higher sulfur coal from other countries, Indonesia in particular.

The natural gas and CO₂ price sensitivity cases show that lower domestic natural gas prices or domestic CO₂ regulations would affect coal production in the Powder River Basin. The CO₂ emissions regulations would have the greatest effect. This effect would be highest in the later years when the CO₂ price is highest. In 2037, Powder River Basin and U.S. coal production would decrease by 15 and 16% relative to a comparable no CO₂ emissions regulatory case (scenarios 2 and 24), respectively.

8.5.2 Proposed Rail Line Alternatives

The northern and southern alternatives would incur different construction and transportation costs related to the length of the alternative and distance from markets. In most scenarios (low or medium production at zero, medium, or high terminal growth), the southern alternatives would have, on average, lower production levels than the northern alternatives. This reflects the higher construction cost and longer routes to domestic markets for the southern alternatives, which makes them somewhat less competitive than the northern alternatives. On average, the production across alternatives for the low and medium production levels would be 8.2% lower in the southern alternatives.

Conversely, in just the high production, high growth scenarios, the southern alternatives would have higher production levels, on average, than the northern alternatives. This is because, at high production levels, potentially induced mining from Canyon Creek is included in the southern alternative production estimates. Canyon Creek has higher heat content coal, which can be more economically exported than the lower heat content coal.

The largest production difference between the northern and southern alternatives with the same production and growth levels would be 11 million tons per year, averaged between 2018 and 2037. This would occur in the high production, high terminal capacity growth scenario, with the southern alternatives, having an average annual production of 57 million tons per year (scenario 20) versus the northern alternatives having an average annual production of 46 million tons per year (scenario 11).

8.5.2.1 Northern Alternatives

Northern Alternatives, Low Production Scenarios

The northern alternatives, low production scenarios at zero, high, and medium terminal capacity growth (scenarios 3, 4, and 5) cover the range of export terminal outcomes and the possible expansion of the existing Pacific Northwest export terminals.

In each of these three scenarios, construction of the proposed rail line would result in production of 20 million tons per year from Otter Creek Mine, even though this low production level would offer the least economies of scale compared to higher production levels (Table 8-8). Under these scenarios, all of the produced coal would be consumed domestically, almost entirely within the Great Lakes region, with a small portion of coal consumed in the Midwest, North region.⁴ The rail distance advantage that Tongue River coal would have for domestic destinations makes it a primary choice for coal plants in these regions.

⁴ The Great Lakes region includes coal plants in Michigan and Wisconsin, as well as the Bay Shore plant in northern Ohio. The Midwest, North region includes coal plants in Minnesota.

**Table 8-8. Northern Alternatives Tongue River Annual Coal Production by Scenario and Year
(million tons per year)**

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
3	Northern	Low	Zero	N, Low, Zero	20.0	20.0	20.0	20.0
4	Northern	Low	Medium	N, Low, Med	20.0	20.0	20.0	20.0
5	Northern	Low	High	N, Low, High	20.0	20.0	20.0	20.0
6	Northern	Medium	Zero	N, Medium, Zero	20.0	32.0	32.0	31.9
7	Northern	Medium	Medium	N, Medium, Medium	20.0	32.0	32.0	32.0
8	Northern	Medium	High	N, Medium, High	20.0	32.0	32.0	32.0
9	Northern	High	Zero	N, High, Zero	34.0	50.0	50.0	37.9
10	Northern	High	Medium	N, High, Medium	34.0	50.0	50.0	50.0
11	Northern	High	High	N, High, High	34.0	50.0	50.0	50.0

Overall, Powder River Basin coal production, averaged over 2018 to 2037, would increase from 484 to 523 to 570 million tons per year with zero, medium, and high terminal capacity growth, respectively (Table 8-9). The lowest single-year Powder River Basin coal production would be 478 (in 2037), 499 (in 2018), and 521 (in 2018) million tons per year for the zero, medium, and high terminal capacity growth scenarios. The highest single-year coal production would be 499 (in 2023), 550 (in 2023), and 602 (in 2023) million tons per year for the zero, medium, and high terminal capacity growth scenarios (scenarios 3, 4, and 5). The growth in overall Powder River Basin production would be proportional to the growth in export terminal handling capability.

**Table 8-9. Northern Alternatives Powder River Basin Annual Coal Production by Scenario and Year
(million tons per year)**

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	478.6	498.8	479.5	478.2	483.8
4	Northern	Low	Medium	N, Low, Med	498.8	550.2	516.5	528.3	523.4
5	Northern	Low	High	N, Low, High	520.7	602.3	571.9	586.5	570.3
6	Northern	Medium	Zero	N, Med, Zero	479.2	499.5	484.5	481.4	486.2
7	Northern	Medium	Medium	N, Med, Med	499.9	551.5	519.7	529.9	525.3
8	Northern	Medium	High	N, Med, High	520.3	605.3	573.2	587.8	571.7
9	Northern	High	Zero	N, High, Zero	481.2	499.2	487.0	481.4	487.2
10	Northern	High	Medium	N, High, Med	504.0	553.8	526.6	531.9	529.1
11	Northern	High	High	N, High, High	529.0	609.0	575.6	588.2	575.5

In certain scenarios (scenarios 3, 4, 5, 6, 9, 12, 13, 14, 15, 16, 17, 18, 21, 22, and 23) where Tongue River coal would not be exported to Asia, export terminals for Powder River Basin

coal shipments to Asia would nonetheless be fully used at 100% of export capacity in all scenarios and in all years. Higher heat content Montana coal (i.e., 9,300 Btu/lb Spring Creek coal) and high heat content Wyoming coal (i.e., 8,800 Btu/lb Black Thunder, Antelope, and North Antelope/Rochelle coal) are preferred for export. Coal with a higher heat content is more competitive for the higher transportation distances to Asia, even if Tongue River coal is located closer to the terminals relative to the other Powder River Basin coal.

Northern Alternatives, High Production Scenarios

The northern alternatives, high production scenarios at zero, high, and medium terminal capacity growth (scenarios 9, 10, and 11) provide an upper bound on the potentially induced coal production from the northern alternatives. These scenarios have high production and include three terminal capacity scenarios.

In the zero terminal capacity growth scenario (scenario 9), the proposed rail line would not induce the maximum available tonnage of 34 million tons per year from Otter Creek Mine and 16 million tons from the Poker Jim Creek–O’Dell Creek deposit (Table 8-8). Instead, production in 2037 (a model run year—see Chapter 5, *Model Framework, Methods, and Key Assumptions*) would drop off as the Poker Jim Creek–O’Dell Creek deposit produces only 3.9 million tons per year (with Otter Creek Mine still producing 34 million tons per year). This decrease would reduce Tongue River coal production over the 20-year analysis period (2018 to 2037). In the medium and high terminal capacity growth scenarios (scenarios 10 and 11), the maximum available tonnage would be produced: 34 million tons per year for Otter Creek Mine in 2018 and 50 million tons per year combined for Otter Creek Mine and the Poker Jim Creek–O’Dell Creek deposit in 2023 and beyond.

Under these high production scenarios, Tongue River coal would be consumed both domestically and internationally. In the scenarios with no export growth (scenarios 3, 6, 9, 12, 15, 18, 21), Tongue River coal would be consumed primarily in the western Great Lakes region, and to a lesser extent in the eastern Great Lakes region, followed by the Midwest, North region, and to a lesser degree in the Great Plains.⁵ As the export terminal capacity increases (i.e., transitioning from zero to medium to high growth), the distribution of Tongue River coal would shift from deliveries to the eastern Great Lakes region to the Pacific Northwest. The coal would be consumed at coal plants in the Pacific Northwest (TransAlta’s Centralia Generating facility), as well as exported via Pacific Northwest terminals for consumption in Asia. Tongue River coal deliveries to the western Great Lakes region, the Midwest, North region, and the Great Plains would remain relatively unchanged with the expansion of the export terminals.

Overall, Powder River Basin coal production would increase from 487 to 529 to 576 million tons per year in the scenarios with zero, medium, and high terminal capacity growth, respectively (Table 8-9). The lowest single-year Powder River Basin coal production would

⁵ The eastern Great Lakes region includes coal plants in Michigan, and the Bay Shore plant in northern Ohio. The western Great Lakes region includes coal plants in Wisconsin. The Midwest, North region includes coal plants in Minnesota.

be 481 (in 2018), 504 (in 2018), and 529 (in 2018) million tons per year for the zero, medium, and high terminal capacity growth scenarios. The highest single-year coal production would be 499 (in 2023), 554 (in 2023), and 609 (in 2023) million tons per year for the zero, medium, and high terminal capacity growth scenarios. The growth in overall Powder River Basin coal production would be proportional to the growth in export terminal capacity. Powder River Basin coal production would be, on average, about 1% (4 to 6 million tons per year) higher than in the northern alternatives, low production scenarios.

8.5.2.2 Southern Alternatives

Southern Alternatives, Low Production Scenarios

The southern alternatives, low production scenarios at zero, high, and medium terminal capacity growth (scenarios 12, 13, and 14) reflect the effects of higher construction and transportation costs. While Otter Creek Mine, at 20 million tons per year of production, would be fully economically viable in all run years for the scenarios with medium and high terminal capacity growth (scenarios 13 and 14), with zero terminal capacity growth (scenario 12), Otter Creek would not be fully economically viable in all years (Table 8-10). This stands in contrast to the northern alternative, low production, zero terminal capacity growth scenario (scenario 3), where Otter Creek Mine would be fully economically viable in all years.

Table 8-10. Southern Alternatives Tongue River Annual Coal Production by Scenario and Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
12	Southern	Low	Zero	S, Low, Zero	20.0	20.0	10.7	4.6
13	Southern	Low	Medium	S, Low, Med	20.0	20.0	20.0	20.0
14	Southern	Low	High	S, Low, High	20.0	20.0	20.0	20.0
15	Southern	Medium	Zero	S, Medium, Zero	20.0	32.0	31.0	16.8
16	Southern	Medium	Medium	S, Medium, Med	20.0	32.0	32.0	28.5
17	Southern	Medium	High	S, Medium, High	20.0	32.0	32.0	28.4
18	Southern	High	Zero	S, High, Zero	34.0	50.0	69.4	56.0
19	Southern	High	Medium	S, High, Med	34.0	50.0	72.0	72.0
20	Southern	High	High	S, High, High	34.0	50.0	72.0	72.0

While the production costs for Otter Creek Mine would be the same under both the northern and southern alternatives, low production scenarios, two factors would likely lead to lower coal production in the southern alternatives.

- The total cost of construction of the proposed rail line would be higher under the southern alternatives.

- The rail distances to primary markets would be longer for the southern alternatives.

Constructing the southern alternatives would be more expensive than the northern alternatives. The total construction cost is annualized and spread over the total maximum production levels. It is then added to the minemouth and rail transportation costs to arrive at a final delivered price for the Tongue River coal. The Tongue River “cost adder” refers to the Tongue River construction costs being leveled into a yearly dollar-per-ton charge. The difference in the Tongue River cost adder between the northern and southern alternatives amounts to \$1.74 per ton (\$4.30 per ton for the southern alternatives at low production levels versus \$2.56 per ton for the northern alternatives at low production levels) or about \$0.10 per MMBtu. This increase is larger than in other production scenarios when the capital costs are amortized over more tons of coal sold. Put another way, there are economies of scale at the higher production levels. The southern alternatives would have a rail distance advantage to the central Midwest, the eastern Ohio River region, and the southwest region compared to the northern alternative, but would not have a rail distance advantage compared to Wyoming Powder River Basin coal, which is even closer. The northern alternatives would have a rail distance advantage over the southern alternatives and Wyoming Powder River Basin to the eastern and western Great Lakes region, the Midwest, North region, the Great Plains region, the western Ohio River region, the Northwest, and the Pacific Northwest export terminals. Some of these regions consume more coal than regions that would be accessed by the southern alternative.

Overall, Powder River Basin coal production would increase from 482 to 524 to 571 million tons per year in the scenarios with zero, medium, and high terminal capacity growth, respectively (Table 8-11). The lowest single-year Powder River Basin coal production would be 474 (in 2030), 499 (in 2018), and 521 (in 2018) million tons per year for the zero, medium, and high terminal capacity growth scenarios. The highest single-year coal production would be 499 (in 2023), 551 (in 2023), and 603 (in 2023) million tons per year for the zero, medium, and high terminal capacity growth scenarios. Powder River Basin coal production would be within 1 to 2 million tons per year of the production levels for the northern alternatives, low production scenario (scenarios 3, 4, and 5).

Table 8-11. Southern Alternatives Powder River Basin Annual Coal Production by Scenario and Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
12	Southern	Low	Zero	S, Low, Zero	478.5	499.1	474.0	475.5	481.8
13	Southern	Low	Medium	S, Low, Med	499.1	550.6	517.2	528.6	523.9
14	Southern	Low	High	S, Low, High	520.6	602.8	572.0	586.9	570.6
15	Southern	Medium	Zero	S, Med, Zero	478.9	498.9	484.0	478.4	485.1
16	Southern	Medium	Medium	S, Med, Med	499.8	551.4	519.3	529.7	525.0
17	Southern	Medium	High	S, Med, High	520.3	605.3	572.5	587.2	571.3
18	Southern	High	Zero	S, High, Zero	481.1	498.8	486.8	481.1	486.9
19	Southern	High	Medium	S, High, Med	504.7	553.4	539.0	535.9	533.3
20	Southern	High	High	S, High, High	528.8	610.8	577.2	590.0	576.7

In these southern alternatives, low production scenarios, Tongue River coal would be delivered primarily to the western Great Lakes region (similar to the northern alternatives, low production scenarios). A small amount of Tongue River coal would be delivered to the eastern Great Lakes region in the zero growth scenario (scenario 12).

Southern Alternatives, High Production Scenarios

The southern alternatives, high production scenarios at zero, high, and medium terminal capacity growth (scenarios 18, 19, and 20) would become more economically viable as production increases (Table 8-10). The Poker Jim Creek–O’Dell Creek deposit would not be fully economically viable in all years with zero terminal capacity growth. However, with high and medium terminal capacity growth, Otter Creek Mine, Poker Jim Creek–O’Dell Creek deposit, and Canyon Creek deposit would be economically viable in all run years. Minemouth production costs in the high production scenarios would be slightly less than in the low production scenarios because of higher equipment utilization rates. The overall cost of the proposed rail line was annualized in the same way as in the low production scenario, but would now be spread over a greater total production volume. Thus, its dollar-per-ton charge for the railroad would be \$1.19 per ton in the high production scenarios compared to the \$4.30 per ton charge in the low production scenarios. These production cost and overall cost differences translate to increased competitiveness for Tongue River coal in the high production scenario.

Overall, Powder River Basin coal production would increase from 487 to 533 to 577 million tons per year in the scenarios with zero, medium, and high terminal capacity growth, respectively (Table 8-11). The lowest single-year Powder River Basin coal production would be 481 (in 2018), 505 (in 2018), and 529 (in 2018) million tons per year for the zero, medium, and high terminal capacity growth scenarios. The highest single-year coal

production would be 499 (in 2023), 553 (in 2023), and 611 (in 2023) million tons per year for the zero, medium, and high terminal capacity growth scenarios. This production level is comparable to production in the northern alternative, high production scenarios.

The higher heat content (9,100 Btu/lb) Canyon Creek coal would become available in 2030, and a maximum output of 22 million tons per year would be exported to Asia in all years. Relative to Wyoming Powder River Basin coal with a heat content of 8,800 Btu/lb, Canyon Creek coal would be more competitive for export because it holds a rail distance advantage to the Pacific Northwest, has higher heat content, and would have low production costs compared to other mines, because it would have a stripping ratio of 2.5 bank cubic yards (BCY) per ton.⁶

For the southern alternatives, high production scenarios, as the export terminals expand in the Pacific Northwest, Tongue River coal deliveries would shift primarily from the eastern Great Lakes region to the Pacific Northwest terminals for export to Asia. Consumption in the western Great Lakes region would remain relatively unchanged at about 21 to 24 million tons per year, similar to the levels of consumption in the western Great Lakes region in the northern alternative, high production scenarios.

8.5.2.3 Northern and Southern Alternatives, Medium Production Scenarios

The results from the medium production scenarios for both the northern and southern alternatives are generally between the results from the low production and high production scenarios (Tables 8-8 through 8-11). Generally, Tongue River coal would be delivered to the same locations as in low and high production scenarios. Some portion of Tongue River coal would be exported to Asia under the northern alternatives for all growth scenarios.

8.6 Natural Gas and Carbon Dioxide Price Sensitivities

8.6.1 Natural Gas Price Sensitivity

The northern alternatives, low production, zero terminal capacity growth and low natural gas prices scenario (scenario 21) tests the sensitivity of coal production to natural gas prices. OEA's analysis shows that under this scenario, Otter Creek coal would still be produced economically at 20 million tons, despite increased competition from lower natural gas prices (Table 8-12). Overall Powder River Basin coal production would decrease by 4.8%, from 484 million tons per year to 461 million tons per year, averaged between 2018 and 2037,

⁶ *Bank cubic yards* refers to the cubic yards of earth not yet blasted or removed (still in place). Blasting the earth for removal causes it to swell, so that a bank cubic yard of earth would take up the same space as about 1.25 cubic yards of loose earth.

when comparing this scenario using low economic growth natural gas prices⁷ against the scenario with *expected case* natural gas prices (scenario 3) (Table 8-13). Between scenarios 3 and 21, the range of the change in Powder River Basin coal production would range from a decrease of 61 million tons, or 12.8% in 2018, to an increase of 4.6 million tons, or 1.0% in 2030. In 2018, the difference in natural gas prices between the two scenarios (scenario 3 and 21) is about \$1/MMBtu. However, by 2030 the natural gas prices between the two scenarios (scenario 3 and 21) are within \$0.1/MMBtu and remain that close through 2037, thus the larger production difference in the early years.

Table 8-12. Natural Gas Price Sensitivity: Tongue River Coal Production by Scenario and Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
21	Northern	Low	Zero	N, Low, Zero, Low Gas	20.0	20.0	20.0	20.0
22	Northern	Low	High	N, Low, High, Low Gas	20.0	20.0	20.0	20.0

Table 8-13. Natural Gas Price Sensitivity: Powder River Basin Coal Production by Scenario and Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
21	Northern	Low	Zero	N, Low, Zero, Low Gas	417.6	464.2	484.1	476.9	460.7
22	Northern	Low	High	N, Low, High, Low Gas	468.7	573.0	571.1	585.0	549.5

A second low natural gas sensitivity, the northern alternative, low production, high terminal capacity growth, and low natural gas prices scenario (scenario 22) shows that Otter Creek coal would still be produced economically at 20 million tons per year, despite increased competition from lower natural gas prices (Table 8-12). Overall Powder River Basin production would decrease by 3.6%, from 570 million tons per year to 550 million tons per year, averaged between 2018 and 2037, when comparing a scenario with *expected case* natural gas prices (scenario 5) against lower *low economic growth* natural gas prices (Table 8-13). Between scenarios 5 and 22, the range of the change in Powder River Basin coal production would range from a decrease of 52 million tons, or 10.0% in 2018, to a decrease of 0.8 million tons, or 0.1% in 2030. The effect of the lower natural gas prices is somewhat moderated by the higher export capacity. For example, a decrease in natural gas prices of \$1/MMBtu would result in a 10 million ton per year smaller reduction in Powder

⁷ The *low economic growth* natural gas price case is defined by the U.S. Energy Information Administration as a case with slightly lower natural gas prices compared to the *expected case* natural gas prices case.

River Basin coal production in the high terminal capacity growth scenario (scenario 22) than in the zero terminal capacity growth scenario (scenario 5). The export terminals with a capacity of 122 million tons per year would be fully used with exports to Asia of approximately 50% high heat content Montana coal and 50% Wyoming 8800 Btu/lb coal. Under this scenario, Tongue River coal production would continue to be primarily delivered to the western Great Lakes region with a small share to the Midwest, North region.

8.6.2 Carbon Dioxide Price Sensitivity

The northern alternatives, low production, high growth scenario with a CO₂ price included (scenario 23), shows that Otter Creek coal would still be produced economically at 20 million tons, despite higher dispatch costs for coal plants in the form of a rising price on CO₂ emissions starting in 2023 (Table 8-14). Overall Powder River Basin production would decrease by 8.1%, from 570 million tons per year to 524 million tons per year, averaged between 2018 and 2037, when comparing a scenario without a price on CO₂ against a scenario with a price on CO₂ (Table 8-15). The maximum Powder River Basin coal production decrease would be 14.7% in 2037 and the minimum Powder River Basin coal production decrease would be 1.8% in 2018.

Table 8-14. Carbon Dioxide Price Sensitivity: Tongue River Coal Production by Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037
23	Northern	Low	High	N, Low, High, Yes CO ₂	20.0	20.0	20.0	20.0

Table 8-15. Carbon Dioxide Price Sensitivity: Powder River Basin Coal Production by Year (million tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
23	Northern	Low	High	N, Low, High, Yes CO ₂	511.5	568.2	516.2	500.2	524.0

The reduction in Powder River Basin coal production would increase as the CO₂ price increases over time. By 2037, Powder River Basin coal production in scenario 23 would decrease by 14.7% from scenario 5. The export terminals with capacity of 122 million tons per year would be fully used with exports to Asia of approximately 40% high heat content Montana coal and 60% Wyoming 8800 Btu/lb coal. Tongue River coal production would continue to be primarily delivered to the western Great Lakes region with small shares to the Midwest, North region and the Great Plains.

8.7 Production Cost Sensitivity

8.7.1 Tongue River Production Cost Sensitivity

When production costs are increased by 20% relative to the original cost estimates, the Otter Creek Mine would continue to be fully economically viable in all years, for all growth scenarios. Thus, even if the original production cost estimates were underestimated by 20%, the same levels of Tongue River coal production could be expected. A 20% increase in production cost would represent an increase of approximately \$2 per ton or \$0.13 per million Btu. The distance advantage of Tongue River Coal over competing Powder River Basin coal (200 to 300 fewer miles to markets) would insulate Tongue River coal from a moderate cost increase. In addition, the production costs are typically less than 50% of the delivered costs of Powder River Basin coal; thus, a 20% increase in production costs would result in a delivered cost increase of only between 5 and 7%.

If production costs were to increase above 20%, the annual production and years of economically viable production would decline steadily until Otter Creek Mine would no longer be economically viable at any production level or year. This would occur if production costs increase by 80% for the northern alternative, low production, zero growth scenario and if production costs increased by 100% for the northern alternatives, high production, high growth scenario.

Poker Jim Creek–O’Dell Creek deposit’s higher production volume of 16 million tons would be economically viable in all years even at an increase of 10% in production costs. At a 20% increase, it would no longer be competitive in 2030 or 2037; at a 35% increase, it would no longer be competitive in 2030 or 2037; and at a 50% increase, it would no longer be economically viable in any year.

Tongue River coal production would be more economically viable with high production and high growth scenarios for two reasons.

- The mines that have higher production would enjoy economies of scale, which translate to cost savings.
- The expansion of the Pacific Northwest terminals that is reflected in these scenarios would significantly increase the market for all Powder River Basin coal.

These conclusions are evident in comparing the northern alternative, low production, zero terminal growth scenario and the northern alternative, high production, high growth case (Tables 8-16 and 8-17).

Table 8-16. Cost Sensitivity: Percent Increase from Base Case Prices for Northern Alternatives, Low Production, Zero Growth (million tons per year)

Year	0%	10%	20%	35%	50%	65%	80%	100%
2018	20.0	20.0	20.0	20.0	20.0	5.7	0	0
2023	20.0	20.0	20.0	20.0	6.8	0	0	0
2030	20.0	20.0	20.0	20.0	0	0	0	0
2037	20.0	20.0	20.0	0	0	0	0	0

Table 8-17. Cost Sensitivity: Percent Increase from Base Case Prices for Northern Alternatives, High Production, High Growth (million tons per year)

Year	0%	10%	20%	35%	50%	65%	80%	100%
2018	34.0	34.0	34.0	34.0	34.0	31.1	26.6	20.9
2023	50.0	50.0	50.0	50.0	33.1	28.2	21.8	0
2030	50.0	50.0	50.0	34.0	30.1	28.3	18.5	0
2037	50.0	50.0	34.0	31.8	25.8	0	0	0

8.8 Pacific Basin Coal Production Cost Sensitivity

If the production costs of international suppliers to the Pacific Basin decreased by 20%, Powder River Basin coal would remain competitive and would be exported at the maximum terminal capacity for the northern alternative, high production, high growth scenario. At a 40% reduction of international production costs, however, Powder River Basin coal exports would no longer compete with international coal. This would occur when delivered coal costs are at or below \$3.50 per million Btu (Table 8-18).

Table 8-18. Powder River Basin Export Sensitivity to International Production Costs (million tons per year)

Decrease in International Coal Production Costs (%)	Powder River Basin Exports			
	2018	2023	2030	2037
20	65.0	122.0	122.0	122.0
30	65.0	101.5	74.4	81.6
40	0	0	0	0
50	0	0	0	0

8.9 Summary

Based on modeling results, OEA provides the following responses to the questions posed at the beginning of this chapter.

- *Would construction and operation of the proposed rail line induce additional coal production in the Tongue River area?*

Construction and operation of the proposed rail line could induce additional coal production beyond production from the Otter Creek mine. Tongue River coal production would be economically viable in most of the scenarios that have been studied. Across all scenarios from 2018 to 2037, coal production would average 30.6 million tons per year, with a range from 13.8 million tons per year to 57 million tons per year.

- *Would Tongue River coal displace coal production in the Powder River Basin, in the United States, and in the world?*

Each ton of Tongue River coal produced, on average across all 21 primary sensitivity scenarios and averaged from 2018 to 2037, would reduce other Powder River Basin coal production by 0.76 ton, and other U.S. coal production by 0.95 ton. The displacement of other Powder River Basin coal would range from 0.57 ton to 0.88 ton, and the displacement of other U.S. coal would range from 0.90 ton to 1.00 ton.

- *Would construction and operation of the proposed rail line affect the level of coal exports?*

Assuming that the proposed new coal export capacity is constructed, Powder River Basin coal would be exported through the export terminals whether or not the proposed rail line were licensed and constructed. Tongue River coal would not affect the level of Pacific Northwest exports of Powder River Basin coal to the Pacific Basin. Under certain scenarios, however, some Tongue River coal would displace other Powder River Basin coal when exported out of the Pacific Northwest.

- *Where would Tongue River coal be distributed to in the United States?*

Tongue River coal would primarily be distributed to the Upper Midwest.

- *How would Tongue River coal production affect rail traffic?*

Tongue River coal production would primarily affect rail traffic near the proposed rail line. Much of the existing Powder River Basin rail traffic would experience little change because Tongue River coal would displace significant amounts of Powder River Basin coal.

- *How would the uncertainties of production costs, natural gas prices, and carbon dioxide (CO₂) prices affect Tongue River coal production and export?*

At moderate levels of production cost increases (20%), or lower natural gas prices, or a price on CO₂, Tongue River coal production and export would remain virtually unchanged. However, lower natural gas prices or a price on CO₂ would decrease the production of Powder River Basin coal and overall U.S. coal.

- *How would total Powder River Basin coal production and transport change across Tongue River coal production and export terminal capacity growth scenarios?*

Total Powder River Basin coal production and transport would experience small changes across different levels of Tongue River coal production. Total Powder River Basin coal production and transport would experience large changes across export terminal capacity growth scenarios.

In summary, coal production and associated rail traffic would be most likely to increase under high production levels and high export terminal capacity growth. However, this increase represents a relatively small increase over the No-Action Alternative, and incrementally smaller increases over current coal production in the United States and throughout the world.

9.1 Introduction

This chapter provides detail on the rail route segments and the projected net change in train volumes on each route segment for the 18 *primary sensitivity scenarios*, plus three No-Action Alternative scenarios.¹ For each of the scenarios and for each route segment, OEA estimates that Tongue River coal would either add to the projected volume of coal movements or displace projected movements of one or more of the following coals.

- Coal originating in the Montana Powder River Basin, not induced by the proposed Tongue River Railroad.
- Coal of 8,800 British thermal units per pound (Btu/lb) originating in the Wyoming Powder River Basin (Wyoming 8800).
- Coal of 8,400 Btu/lb originating in the Wyoming Powder River Basin (Wyoming 8400).

Each of the 18 action scenarios projects an annual coal production volume for the following representative years: 2018, 2023, 2030, and 2037. Chapter 5, *Modeling Framework, Methods, and Key Assumptions*, describes these model years. This analysis describes the changes in the train volume of the high, medium, and low production scenarios for those four representative years.² Nine of the scenarios assume a northern alternative would be built and nine assume a southern alternative would be built. Three scenarios assume no Tongue River Railroad would be built (No-Action Alternative scenarios).

This chapter includes a set of assumptions OEA made in its analysis of the proposed rail transportation routes, estimates of rail segment capacity, projected changes in train volume

¹ The 18 primary sensitivity scenarios include all possible combinations of the northern and southern alternatives, three coal production levels (low, medium, high), three terminal growth capacity levels (zero, medium, high). The three additional low natural gas or CO₂ scenarios (for a total of 21 primary sensitivity scenarios) have been excluded from this rail route analysis. In addition to these primary sensitivity scenarios, there are three No-Action Alternative scenarios for each of the three port capacity levels. There are an additional three No-Action Alternative scenarios (for a total of six No-Action Alternative scenarios) for low natural gas or a price on CO₂. All scenarios are described in Chapter 7, *Scenarios*. Each of the primary sensitivity scenarios, relative to a No-Action Alternative scenario, largely results in Tongue River-originated coal replacing other Powder River Basin coal from Montana or Wyoming to individual destinations. For some movements, Tongue River coal would likely move over different routes than those serving other Powder River Basin coal. The net impact on coal train volumes is generally to increase volumes on some parts of the BNSF system and reduce volumes on other sections of the system. The train volumes described in the text are always the *net change in train volume* resulting from each scenario.

² The terms *coal trains* and *coal volumes* referred to throughout this chapter refer only to coal volumes and proposed rail line coal trains for coal movements to destinations that the model projects would be affected by Tongue River coal. Other coal trains and coal volumes are not moving to proposed rail line-affected destinations and these coal volumes are not analyzed separately, but are included with total train traffic discussed throughout this chapter. Total train traffic levels are adjusted over time based on the forecast changes in traffic levels for a group of rail movements, and not specifically by the model results. The changes in net volumes for coal trains referred to throughout this chapter are changes in the coal trains on the BNSF system that are related to the proposed rail line as analyzed by the model.

by scenario, projected traffic volumes for the alternatives, and coal pricing based on origin areas. Note that these assumptions were made in 2013 and that BNSF planned to spend \$5.5 billion in 2014 and plans to spend \$6.0 billion in 2015 on system upgrades. Some of those upgrades may affect the rail segments being analyzed in this study.

9.2 Assumptions

This section addresses the assumptions OEA made in the analysis of proposed rail transportation routes, i.e., origins and destinations, traffic, train statistics, and rail routes.

9.2.1 Origins and Destinations

For each supply region, a representative coal mine was chosen for OEA's rail route and traffic modeling and analysis. For each destination demand region, a representative power plant or terminal was also chosen. OEA chose representative coal mines and power plants based on the coal supply region to demonstrate potential coal shipments and rail routes, as not all mines and power plant combinations can be efficiently modeled. These supply and demand regions are established by the model described in Chapter 7, *Scenarios*. OEA assumed that all of the coal shipments would originate on BNSF Railway Company (BNSF) routes or on the Tongue River Railroad connecting to BNSF routes.

Some of the representative destination plants or terminals are on railroads with which BNSF connects; however, those carriers would likely already be carrying Powder River Basin coal interchanged from BNSF at the same locations as Tongue River Railroad originated coal so the impact on carriers other than BNSF would be minimal. The analysis, therefore, is limited to changes on the BNSF routes. The coal origins and mines are defined in Table 9-1 and the destinations and rail routes in Table 9-2.

Table 9-1. Coal Origins

Coal Supply Region	Representative Mine	Rail Station
Tongue River coal	Otter Creek ^a	Ashland, MT ^a
Other MT Powder River Basin coal	Spring Creek	Nerco Jct., MT
WY Powder River Basin coal (8800 Btu)	Black Thunder	Thunder Jct, WY
WY Powder River Basin coal (8400 Btu)	Belle Ayr	Belle Ayr, WY
Notes:		
^a Otter Creek is not in operation and Ashland is the projected Tongue River Railroad station.		

Table 9-2. Coal Destinations

Destination Region^a	Destination Plant/Port	Destination Rail Station^b	Rail Route	BNSF Destination
Pacific Basin	Millennium Bulk Terminal	Longview, WA	BNSF	Longview, WA
Pacific Basin	Gateway Pacific Terminal	Cherry Point, WA	BNSF	Cherry Point, WA
Pacific Basin	Morrow Pacific	Boardman, OR	BNSF-WALUL-UP	Wallula, WA
Pacific Basin	Fraser Surrey Docks	Fraser Surrey Impex, BC	BNSF	Fraser Surrey Impex
Pacific Basin	Westshore Terminals	Roberts Bank, BC	BNSF	Roberts Bank, BC
Great Plains	Stanton, ND	Stanton, ND	BNSF	Stanton, ND
Great Lakes, East	Monroe, MI	Monroe, MI	BNSF-CHGO-NS	Chicago, IL
Great Lakes, West	Columbia, WI	Columbia, WI	BNSF-STPAU-CPRS	St. Paul, MN
Midwest, North	Clay Boswell	Cohasset, MN	BNSF	Cohasset, MN
Northwest	Centralia Complex	Centralia, WA	BNSF	Centralia, WA
Great Lakes, Barge	MERC Terminal	Superior, WI	BNSF	Superior, WI

Notes:

^a Pacific Basin incremental export volumes are divided among terminals based on their proposed annual coal capacity: Millennium 48 million tons, Gateway 53 million tons, Morrow 9 million tons, and Fraser Surrey Docks 4 million tons (total of 114 million incremental tons). The high export Scenario (122 million tons) includes 8 million tons to Westshore Terminals.

^b These destination rail stations represent an approximation of the closest rail station to a theoretical tonnage-weighted centroid of all coal-consuming power plants within a certain destination region.

9.2.2 Traffic Eliminated from the Analysis

Several of the modeling results show scenarios with a projected displacement of Illinois Basin coal. The amounts were small—approximately 0.33 million ton in 2030 and 0.82 million ton in 2037. In addition, the modeling showed no impact in 2018 or 2023. As a result, the displacement of Illinois Basin coal was eliminated from OEA’s analysis. See General modeling output results in Chapter 8, *Coal Production and Transportation Modeling Results*.

Several scenarios projected changes in an additional demand category, Industrial Demand, which includes coal consumption by industry for on-site power production, as well as projected future coal-to-liquids plants that would use Wyoming 8400 and 8800 Btu/lb coals. Because the industrial demand is small (less than 300,000 tons per year), and the coal-to-liquids plants do not exist today and any that are eventually built would likely be located close to mines, their impact on the national rail system would be minimal. Therefore, industrial demand was eliminated from OEA’s rail analysis.

9.2.3 Train Statistics

OEA estimated the number of coal trains based on the tons of coal shipped using the parameters in Table 9-3.

Table 9-3. Train Parameters

Parameter	Tongue River and Powder River Basin Trains
Locomotives/train ^a	4
Freight cars/train ^a	125
Lading tons per Tongue River or Powder River Basin car ^b	118
Lading tons per Tongue River or Powder River Basin train ^c	14,750
Empty return ratio for Tongue River or Powder River Basin trains ^d	100%
Notes:	
^a OEA estimated up to four locomotives and 125 cars on average based on the TRRC's response to the first information request (February 6, 2013). This is also consistent with current BNSF westbound coal unit train operation and provides an upper bound because eastbound trains have three locomotives and 118 cars on average.	
^b Estimate based on current operation	
^c Line 3 multiplied by Line 2	
^d Estimate based on current operation	

9.2.4 Rail Routes

OEA projected each movement of Powder River Basin coal consistent with current BNSF operations. However, in several cases BNSF has alternative routes for all or part of the movement. As volume increases on any one-line segment, BNSF may redistribute the traffic over existing tracks to increase capacity on a segment.

The coal movements involve virtually every mainline route in the northern half of the BNSF system (Figures 9-1 and 9-2). The proposed Tongue River Railroad routes to eastern and western destinations would differ, depending on whether a northern or southern alternative were licensed and constructed.

9.3 Rail Segment Capacity

OEA estimated the practical current capacity of each route segment in number of trains per day based on the method used in the Cambridge Systematics Study where capacity was measured based on three primary factors: number of main tracks, traffic control systems, and train types. The study compared existing rail corridor volumes against existing capacity, as well as future volumes, and examined potential infrastructure improvements necessary for line and facility expansions to accommodate these volumes (Cambridge Systematics 2007).

9.3.1 Number of Main Tracks

Most of the route segments in OEA's analysis have one main track with multiple sidings for trains to meet or pass, but there are several segments with two or three main tracks.

Figure 9-1. BNSF Routes Westbound to Pacific Northwest Terminals

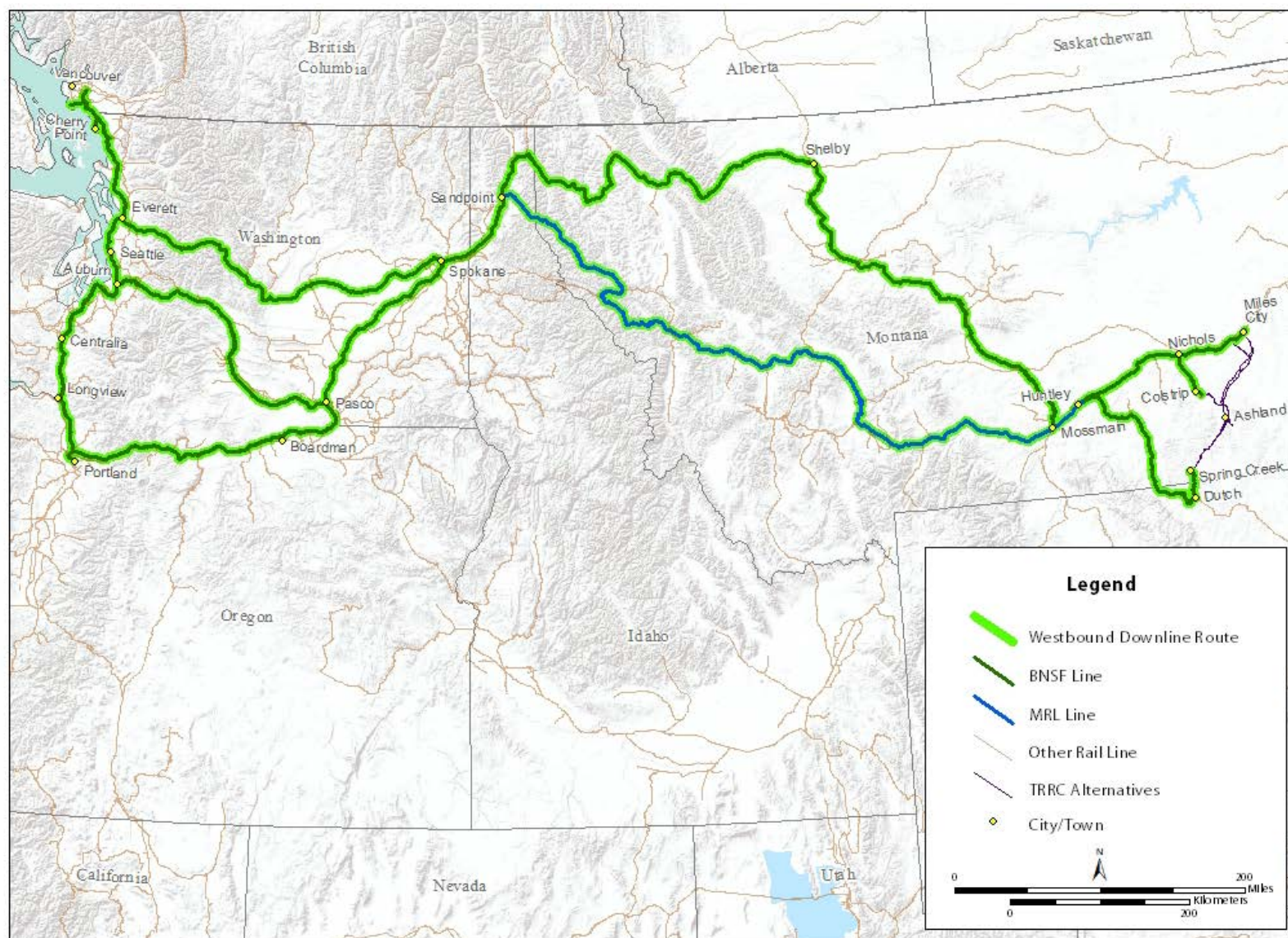
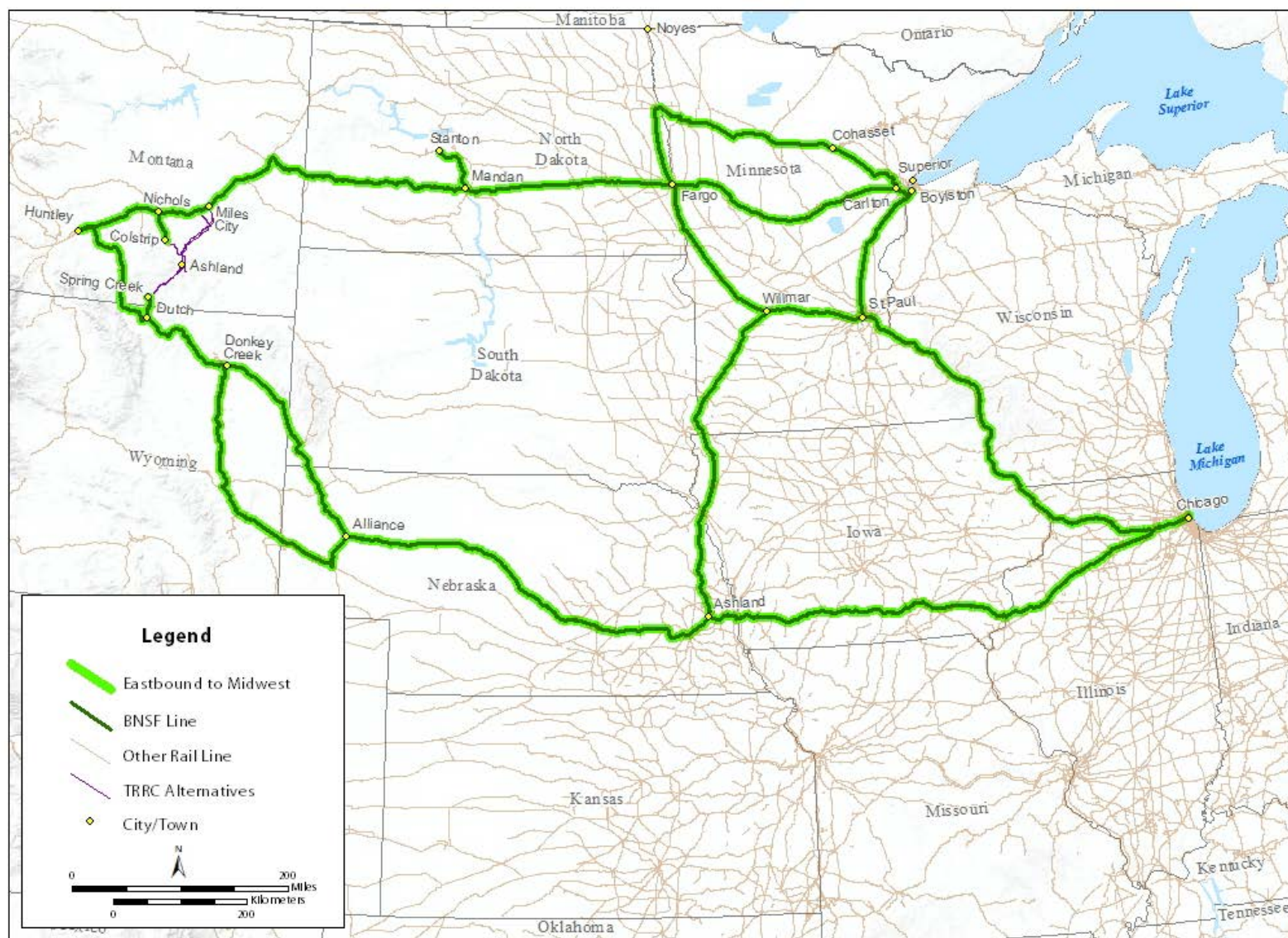


Figure 9-2. BNSF Routes Eastbound to Midwest Terminals



9.3.2 Traffic Control Systems

Traffic control systems help maintain a safe distance between trains passing or meeting on the same track. There are three basic types of systems.

- **Traffic Warrant Control (TWC) or No Signals.** Under these basic control systems, train crews obtain permission or a warrant from the dispatcher to occupy a given piece of railroad. Usually this is done by phone, radio, or electronic transmission to the locomotive. It is the least costly system and is generally used on the low-density track where capacity is generally not an issue.
- **Automatic Block Signals (ABS).** ABS is an electronic signal system that can control when a train can advance into the next block. A block is a section of track with signals at each end. Generally, only one train can occupy a block at one time. The signals provide information to the train crew about speed and they provide information about the occupancy of the blocks ahead. Trains can generally run faster and closer together than under TWC.
- **Centralized Traffic Control (CTC) and Traffic Control Systems (TCS).** With CTC, electrical circuits monitor the location of trains allowing dispatchers to control train movements from a remote location, usually a central dispatching office. The signals automatically prevent trains from entering sections of track occupied by other trains. The signals can be controlled by the dispatcher allowing trains to operate closer together than under ABS, thus increasing capacity.

9.3.3 Train Types

Different train types such as passenger, intermodal, automotive, coal unit, and general manifest trains operate at different speeds. The different train speeds require a larger separation on a route segment than if the segment were only occupied by trains of the same type. For the purpose of this analysis, multiple train types were assumed for OEA's capacity analysis.

Table 9-4 presents data on estimated capacity based on number of main tracks and traffic control systems. Where a segment had more than one traffic control system or more than one configuration of main tracks, the capacities of each type were averaged to estimate train capacity over the route segment.

Table 9-4. Average Capacities of Typical Rail Freight Corridors, Trains per Day^a

Number of Tracks	Type of Control	Trains per Day	
		Practical Maximum if Multiple Train Types use Corridor ^b	Practical Maximum if Single Train Type uses Corridor ^c
1	N/S or TWC	16	20
1	ABS	18	25
2	N/S or TWC	28	35
1	CTC or TCS	30	48
2	ABS	53	80
2	CTC or TCS	75	100
3	CTC or TCS	133	163
4	CTC or TCS	173	230
5	CTC or TCS	248	340
6	CTC or TCS	360	415

Notes:

^a The table presents average capacities for typical rail freight corridors. The actual capacities of the corridors were estimated using railroad-specific capacity tables. At the request of the railroads, these detailed capacity tables were not included in this report to protect confidential and railroad business information.

^b For example, a mix of merchandise, intermodal, and passenger trains

^c For example, all intermodal trains

Source: Class I railroad data aggregated by Cambridge Systematics, Inc.

N/S-TWC = No Signal/Track Warrant Control; ABS = Automatic Block Signaling; CTC-TCS = Centralized Traffic Control/Traffic Control System

9.4 Projected Traffic Volume by Scenario

This section summarizes the projected change in train volume by scenario, based on the results of the modeling. As discussed in Section 9.1, *Introduction*, projections were developed under each of the scenarios for the years 2018, 2023, 2030, and 2037. Because this analysis covers 53 track segments, 21 scenarios and 4 projection years, the output consists of over 5,000 traffic projections.

For each track segment, Tables 9-5 through 9-7 summarize the projected traffic volume for zero, medium and high terminal capacity growth, respectively. The following information is provided.

- Number of route miles, current number of main tracks, traffic control systems and estimated capacity as described in Section 9.3, *Rail Segment Capacity*.
- Total trains in the baseline traffic flow (year 2012). The baseline traffic flow is the average number of trains per day across all of the railroads as provided by the Federal Railroad Administration (2013).
- Baseline project-related coal traffic (2012 base year), which are trains going to destinations that would be potentially affected by Tongue River coal production, as determined by the modeling. These are included in the total baseline traffic flow.

- The change in coal traffic to these destinations resulting from the differences between the three No-Action Alternative scenarios and the 18 action scenarios. These projections were developed using the modeling results.
- The projected 2030 maximum and minimum number of trains over the rail segments based on the 3 No-Action Alternative scenarios and the 18 action scenarios. Projections were developed using the Freight Analysis Framework (Center for Information Analysis 2013) database estimates of growth in non-coal traffic volume. The compound annual growth rate in the framework projections was applied to the 2012 baseline traffic flow minus the coal traffic developed using the modeling results.
- Projections for year 2030. OEA used the year 2030 as a conservative estimate because this is when coal production is maximized across all scenarios.

The short narratives below in Section 9.4.1, *Eastbound Movements*, and Section 9.4.2, *Westbound Movements*, summarize at a high level the segment eastern and western characteristics and flows. The segment specific summaries are in Section 9.5.2, *Projections by Segment*. Other quantitative information about traffic impacts include the sensitivity analyses for natural gas and national carbon dioxide (CO₂) emission regulations, and analysis years 2018, 2023, and 2037.

In summary, the primary changes to rail traffic between the No-Action Alternative and action scenarios would occur in the Powder River Basin, as trains carrying Tongue River coal would displace trains carrying Powder River Basin coal from Wyoming (primarily from the regions associated with Belle Ayr, Wyoming and Thunder Junction, Wyoming). Eastbound and westbound movements are discussed in further detail below.

9.4.1 Eastbound Movements

The northern alternatives would move Tongue River coal over the Forsyth Subdivision to the east via Mandan and Fargo, North Dakota. The southern alternatives would move coal via Huntley, Montana and then east (except for shipments to Chicago, which would move through Alliance, Nebraska). Essentially, Tongue River coal would replace Powder River Basin coal shipments. Incremental volume to Midwest destinations would be very small. However, displacement of Powder River Basin coal by Tongue River coal would change traffic patterns on BNSF lines. The impact of the proposed Tongue River Railroad, regardless of the alternative chosen, would be to increase traffic on the Forsyth Subdivision and decrease it on the route from the Powder River Basin through Alliance, Nebraska.

Table 9-5. Traffic Volume by Scenario, Zero Terminal Capacity Growth

Segments	Segments	Miles	Base-line 2012 ^a	Base-line Study Coal Train Traffic 2012 ^a	No Action (TRRC not built and no Terminal Growth) 2030 -- Scenario 1	Average Change in Rail Traffic by Coal Production Scenario						Total 2030 Future Projections Other than Study Train Traffic
						Northern			Southern			
						Scenario 3	Scenario 6	Scenario 9	Scenario 12	Scenario 15	Scenario 18	
						20 mt/yr	32 mt/yr	50 mt/yr	20 mt/yr	32 mt/yr	72 mt/yr	
Eastbound												
Colstrip to Nichols, Montana	3	29.7	3.0	0.0	0.0	7.4	11.0	17.8	0.0	0.0	0.0	4.8
Nichols to Miles City, Montana	4	51.4	22.0	4.1	10.0	0.5	1.0	7.8	0.2	0.3	1.8	28.7
Spring Creek, Montana to Dutch, Wyoming	6	22.6	9.0	7.0	15.4	-0.9	-1.1	-4.4	2.4	9.3	14.4	3.1
Dutch Wyoming, to Huntley, Montana	7	135.6	15.5	7.0	13.0	-6.9	-10.0	-10.0	0.2	0.3	1.8	13.5
Huntley to Nichols, Montana	5	84.5	20.0	4.1	10.0	-6.9	-10.0	-10.0	0.2	0.3	1.8	25.5
Dutch, Wyoming, to Alliance, Nebraska	9, 10, 11, 12	327	39.0	1.4	3.6	4.5	7.4	4.1	1.0	7.4	11.0	60.0
Alliance, Nebraska, to Chicago, Illinois	15, 25, 30	928.9	34.3	9.3	15.4	-0.3	-0.3	-2.4	-0.1	-0.1	-0.3	40.1
Miles City, Montana to Fargo, North Dakota	16, 17, 18	561.8	18.3	3.9	9.8	0.5	1.0	7.8	0.2	0.3	1.8	23.0
Fargo, North Dakota, to Chicago, Illinois	20, 21, 23, 24, 25	679.3	20.0	1.8	5.6	0.4	0.6	7.2	0.1	0.2	0.1	22.6
Westbound												
Huntley to Mossmain, Montana	34	23.1	10.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	11.2
Mossmain, Montana, to Sandpoint, Idaho	35	562.1	14.5	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	18.4
Sandpoint, Idaho, to Spokane, Washington	38	66.6	36.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	52.8
Spokane to Everett, Washington via Stevens Pass	39	291.7	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.1
Spokane to Auburn, Washington, via Stampede Pass	40, 41	519.9	18.0	1.5	1.5	0.0	0.0	0.0	0.0	0.0	0.0	26.4
Spokane, Washington, to Portland, Oregon via the Columbia River Gorge	40, 43	389.1	35.8	2.9	2.0	0.0	0.0	0.0	0.0	0.0	0.0	52.7
BNSF North-South Line ^b	45, 46, 47, 48, 49, 50, 51, 52, 53	355.3	22.4	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	34.0

See Section 9.5.2, *Projections by Segment*, for further details on segments

^a Baseline traffic data is an average of 2012 FRA data over all subdivisions comprising segment

^b The BNSF North-South Line includes Canadian Routes as identified in Section 9.5.2.5, *Canadian Routes*

Table 9-6. Traffic Volume by Scenario, Medium Terminal Capacity Growth

Segments		Segments	Miles	Baseline 2012 ^a	Baseline Study Coal Train Traffic 2012 ^a	No Action (no Railroad and Medium Terminal Growth) 2018 -- Modeling Scenario 25 ^a	Average Change in Rail Traffic by Coal Production Scenario						Total 2030 Future Projections Other than Coal Train Traffic
							Northern			Southern			
							Scenario 4	Scenario 7	Scenario 10	Scenario 13	Scenario 16	Scenario 19	
							20 mt/yr	32 mt/yr	50 mt/yr	20 mt/yr	32 mt/yr	72 mt/yr	
Eastbound													
Colstrip to Nichols, Montana	3	29.7	3.0	0.0	0.0	7.4	11.5	18.2	0.0	0.0	0.0	4.8	
Nichols to Miles City, Montana	4	51.4	22.0	4.1	2.0	7.4	8.9	14.6	5.7	8.4	8.5	28.7	
Spring Creek, Montana to Dutch, Wyoming	6	22.6	9.0	7.0	21.9	0.0	-0.2	-0.7	6.1	10.0	24.1	3.1	
Dutch Wyoming, to Huntley, Montana	7	135.6	15.5	7.0	24.7	0.0	-2.6	-3.6	5.7	8.4	8.5	13.5	
Huntley to Nichols, Montana	5	84.5	20.0	4.1	2.0	0.0	-1.5	-0.5	5.7	8.4	8.5	25.5	
Dutch, Wyoming, to Alliance, Nebraska	9, 10, 11, 12	327	39.0	1.4	5.9	-0.3	-1.9	-2.8	-0.9	0.7	7.7	60.0	
Alliance, Nebraska, to Chicago, Illinois	15, 25, 30	928.9	34.3	9.3	19.7	-2.4	-2.7	-4.5	-1.9	-2.7	-2.8	40.1	
Miles City, Montana to Fargo, North Dakota	16, 17, 18	561.8	18.3	3.9	1.9	7.4	8.9	14.6	5.7	8.4	8.5	23.0	
Fargo, North Dakota, to Chicago, Illinois	20, 21, 23, 24, 25	679.3	20.0	1.8	3.0	2.5	3.1	8.8	1.9	2.9	2.9	22.6	
Westbound													
Huntley to Mossmain, Montana	34	23.1	10.0	3.0	22.7	0.0	0.0	0.0	0.0	0.0	0.0	11.2	
Mossmain, Montana, to Sandpoint, Idaho	35	562.1	14.5	3.0	22.7	0.0	0.0	0.0	0.0	0.0	0.0	18.4	
Sandpoint, Idaho, to Spokane, Washington	38	66.6	36.0	3.0	22.7	0.0	0.0	0.0	0.0	0.0	0.0	52.8	
Spokane to Everett, Washington via Stevens Pass	39	291.7	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.1	
Spokane to Auburn, Washington, via Stampede Pass	40, 41	519.9	18.0	1.5	11.3	0.0	0.0	0.0	0.0	0.0	0.0	26.4	
Spokane, Washington, to Portland, Oregon via the Columbia River Gorge	40, 43	389.1	35.8	2.9	22.1	0.0	0.0	0.0	0.0	0.0	0.0	52.7	
BNSF North-South Line ^b	45, 46, 47, 48, 49, 50, 51, 52, 53	355.3	22.4	1.2	9.2	0.0	0.0	0.0	0.0	0.0	0.0	34.0	

Notes:

^a Baseline traffic data is an average of 2012 FRA data over all subdivisions comprising segment

^b The BNSF North-South Line includes Canadian Routes as identified in Section 9.5.2.5, *Canadian Routes*

See Section 9.5.2, *Projections by Segment*, for further details on segments

Table 9-7. Traffic Volume by Scenario, High Terminal Capacity Growth

Segments	Segments	Miles	Baseline 2012 ^a	Baseline Study Coal Train Traffic 2012 ^a	No Action (no Railroad and High Terminal Growth) 2018 -- Modeling Scenario 2 ^a	Average Change in Rail Traffic by Coal Production Scenario						Total 2030 Future Projections Other than Coal Train Traffic
						Northern			Southern			
						Scenario 5	Scenario 8	Scenario 11	Scenario 14	Scenario 17	Scenario 20	
						20 mt/yr	32 mt/yr	50 mt/yr	20 mt/yr	32 mt/yr	72 mt/yr	
Eastbound												
Colstrip to Nichols, Montana	3	29.7	3.0	0.0	0.0	7.4	11.5	18.2	0.0	0.0	0.0	4.8
Nichols to Miles City, Montana	4	51.4	22.0	4.1	2.0	7.4	8.7	9.0	5.7	10.2	26.4	28.7
Spring Creek, Montana to Dutch, Wyoming	6	22.6	9.0	7.0	24.1	-2.2	-1.9	-1.9	3.9	8.3	24.5	3.1
Dutch Wyoming, to Huntley, Montana	7	135.6	15.5	7.0	47.4	0.0	-2.8	-9.2	5.7	8.3	8.5	13.5
Huntley to Nichols, Montana	5	84.5	20.0	4.1	2.0	0.0	-1.3	5.1	5.7	8.3	8.5	25.5
Dutch, Wyoming, to Alliance, Nebraska	9, 10, 11, 12	327	39.0	1.4	10.6	-0.5	-3.4	-8.0	0.2	-2.4	-10.7	60.0
Alliance, Nebraska, to Chicago, Illinois	15, 25, 30	928.9	34.3	9.3	19.6	-2.3	-2.6	-2.7	-1.7	-2.6	-2.6	40.1
Miles City, Montana to Fargo, North Dakota	16, 17, 18	561.8	18.3	3.9	1.9	7.4	8.8	9.0	5.7	8.3	8.5	23.0
Fargo, North Dakota, to Chicago, Illinois	20, 21, 23, 24, 25	679.3	20.0	1.8	3.0	2.5	3.0	3.1	2.0	2.8	2.9	22.6
Westbound												
Huntley to Mossmain, Montana	34	23.1	10.0	3.0	45.3	0.0	0.0	0.0	0.0	0.0	0.0	11.2
Mossmain, Montana, to Sandpoint, Idaho	35	562.1	14.5	3.0	45.3	0.0	0.0	0.0	0.0	0.0	0.0	18.4
Sandpoint, Idaho, to Spokane, Washington	38	66.6	36.0	3.0	45.3	0.0	0.0	0.0	0.0	0.0	0.0	52.8
Spokane to Everett, Washington via Stevens Pass	39	291.7	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.1
Spokane to Auburn, Washington, via Stampede Pass	40, 41	519.9	18.0	1.5	22.7	0.0	0.0	0.0	0.0	0.0	0.0	26.4
Spokane, Washington, to Portland, Oregon via the Columbia River Gorge	40, 43	389.1	35.8	2.9	44.2	0.0	0.0	0.0	0.0	0.0	0.0	52.7
BNSF North-South Line ^b	45, 46, 47, 48, 49, 50, 51, 52, 53	355.3	22.4	1.2	18.4	0.0	0.0	0.0	0.0	0.0	0.0	34.0

See Section 9.5.2, *Projections by Segment*, for further details on segments

^a Baseline traffic data is an average of 2012 FRA data over all subdivisions comprising segments

^b The BNSF North-South Line includes Canadian Routes as identified in Section 9.5.2.5, *Canadian Routes*

9.4.2 Westbound Movements

For westbound shipments, train volume was determined by the assumed capacity of the new export coal terminals. The westbound routes for Tongue River coal would be mostly the same as those for Powder River Basin coal. Westbound shipments from Wyoming move through Donkey Creek to Huntley, Montana. Westbound shipments from Montana move through Spring Creek to Dutch, Wyoming, and then to Huntley.

The northern alternatives would move Tongue River coal west on the Forsyth Subdivision to Huntley. From that point, all routes for Tongue River or Powder River Basin coal to Centralia, Washington³ and the Pacific Northwest terminals would be the same. A southern alternative would move coal over the same route as Powder River Basin trains with the addition of Tongue River Railroad miles from Otter Creek to Spring Creek/Nerco Junction, Montana.

High terminal capacity growth scenarios would result in a substantial increase in coal transport to the international market. These scenarios assume that all of the currently planned Pacific Northwest coal export terminals are built, creating an incremental capacity of 114 million tons per year. In addition, about 8 million tons per year of Wyoming Powder River Basin coal are currently transported to Westshore Terminals in Roberts Bank, British Columbia, for a total capacity of 122 million tons per year (Chapter 4, *Proposed Coal Export Terminals and Expansions*). The high terminal capacity growth scenarios assume that Tongue River and Powder River Basin coal would use all of that capacity.

9.5 Projected Traffic Volume for the Alternatives

This section presents the projected traffic volumes for the alternatives and includes assumptions and projections by segment.

9.5.1 Assumptions

OEA made assumptions regarding loading trains at coal mines and traffic volumes for the alternatives.

9.5.1.1 Loading Trains at Coal Mines

OEA assumed that the mine-loading operation for any alternative would have a loop track similar to those at the mines in the Wyoming portion of the Powder River Basin. Coal trains powered by BNSF locomotives would arrive at the mine. The 125-car trains would be loaded in 2 to 3 hours by either a BNSF crew or a train crew contracted by the mine operator.

³ The Centralia Complex is treated as the demand centroid for the Pacific Northwest region in IPM®.

9.5.1.2 Northern Alternatives

The northern alternatives include the Tongue River Alternatives,⁴ Colstrip Alternatives, Tongue River Road Alternatives, and Moon Creek Alternatives.

Tongue River, Tongue River Road, and Moon Creek Alternatives

The Tongue River, Tongue River Road, and Moon Creek Alternatives would extend from the city of Ashland to a connection with the BNSF main line at Miles City, Montana, at approximately milepost 78.6 on the BNSF Forsyth Subdivision. Depending on variations and coal production scenarios, the Tongue River, Tongue River Road, and Moon Creek Alternatives with active train traffic would range from 74.1 to 86.4 miles.

Colstrip Alternatives

The Colstrip Alternatives would extend from the city of Ashland to the city of Colstrip, Montana, where they would connect with the BNSF Colstrip Subdivision at milepost 33. Depending on variations and coal production scenarios, the Colstrip Alternatives with active train traffic would range from 63.7 to 74.8 miles.

9.5.1.3 Southern Alternatives

The southern alternatives consist of the Decker Alternative and the Decker East Alternative, which includes the Terminus 1 Variation.

Decker Alternatives

The Decker Alternatives would run south and west from Ashland to a connection with the BNSF Dutch Subdivision at Spring Creek Mine, Montana (milepost 22.8). Depending on variations, the Decker Alternatives would range from 49.7 to 51.1 miles.

9.5.1.4 Tongue River Railroad Infrastructure and Operation

OEA assumed that all alternatives and variations would have consistent track structure (continuous welded rail), traffic control systems, operating plans, and other infrastructure elements. The line would have one passing siding of 8,500 feet with number 20 turnouts on each end. Several set-out tracks would also be constructed. The line would have the capability to accommodate gross rail loads of up to 315,000 pounds, which is greater than the current BNSF maximum gross weight allowance of 286,000 pounds. The line would not have signals. Traffic control would be by TWC and would be dispatched by BNSF.

⁴ Each northern alternative consists of two variations representing combinations of the primary route or the primary route and Ashland East Variation plus the Terminus 1 Variation. For example, the Tongue River Alternatives consists of the Tongue River Alternative and Tongue River East Alternative.

TRRC indicates that, with no passing sidings, the proposed rail line would have a maximum capacity of three to four loaded trains per day or seven to eight total trains (loaded and empty). With one 8,500-foot siding, which is planned as part of the proposed rail line, the proposed rail line could handle about ten trains per day (five loaded and five empty).⁵

9.5.2 Projections by Segment

9.5.2.1 Tongue River Mines to BNSF

Each build alternative for the proposed rail line is designed to deliver coal from the Otter Creek and potentially induced mines to common connection points on the BNSF rail lines. From these common points, coal would be transported to western markets and export terminals, or to eastern markets. The segments along which the Tongue River coal could be routed to the common connection points are described below.

Tables 9-8 through 9-52 include the following information, by segment.

- Miles, main tracks and traffic control systems on the segment.
- Estimated capacity defined as the current number of trains per day of all types that can be handled on the segment given the number of tracks and the train traffic control system.
- Northern and southern alternatives minimum and maximum change in total trains per day resulting from the proposed rail line along with the year and scenario number in which those minimums and maximums occur.
- Mine production and terminal growth, associated with minimum and maximum change in trains per day.
- Total trains per day (TRRC trains, other coal trains and noncoal trains), proposed rail line trains (coal trains that would originate on TRRC) and No-Action trains (coal trains and non-coal trains that would move on the segment without construction of TRRC) expected under the scenarios producing the minimum and maximum change in trains per day.
- Change in traffic, which is the difference in the number of trains per day between the Total trains with the proposed rail line and No-Action Alternative. Ashland to Colstrip or Miles City, Montana.

Table 9-8 summarizes projected train traffic for the proposed rail line, illustrated in Figure 9-3.

⁵ TRRC Response to OEA's Data Request P-5, February 6, 2013.

Figure 9-3. Ashland to Colstrip or Miles City, Montana (42/84 miles)

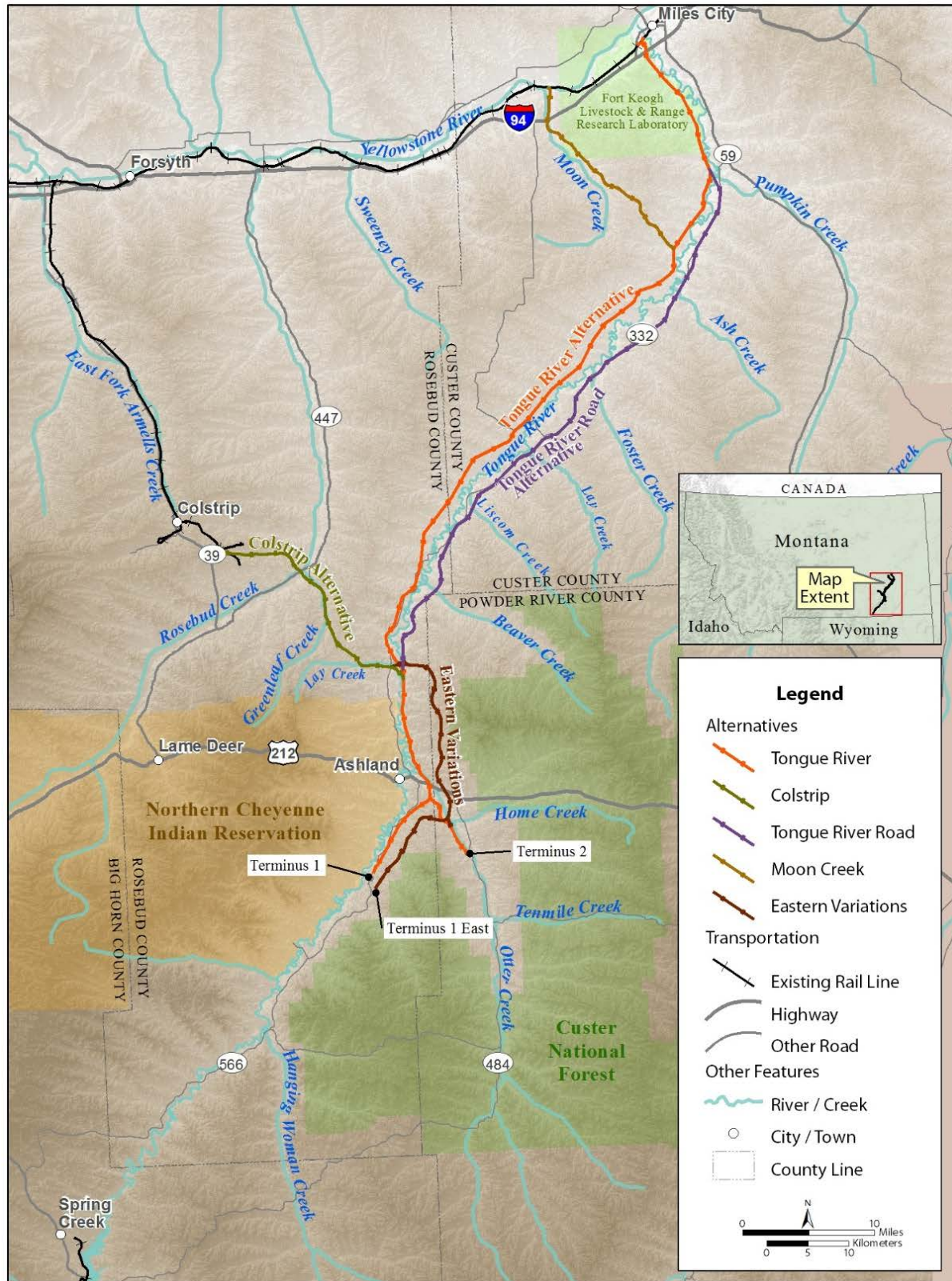


Table 9-8. Ashland, Montana to Colstrip or Ashland to Miles City, Montana

						Change in Traffic, Trains per Day			
Segment 1, 34 or 84 miles, Westbound or Eastbound Main Tracks: 1 Traffic Control System: TWC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	7.4	7.4	0.0	7.4
	Maximum Change in Traffic	9	2023	High	Zero	18.2	18.2	0.0	18.2
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	0.0	0.0	0.0	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	0.0	0.0	0.0	0.0

Ashland to Spring Creek, Montana

Table 9-9 summarizes projected train traffic for this segment, illustrated in Figure 9-4.

Figure 9-4. Ashland to Spring Creek, Montana (29.7 miles)

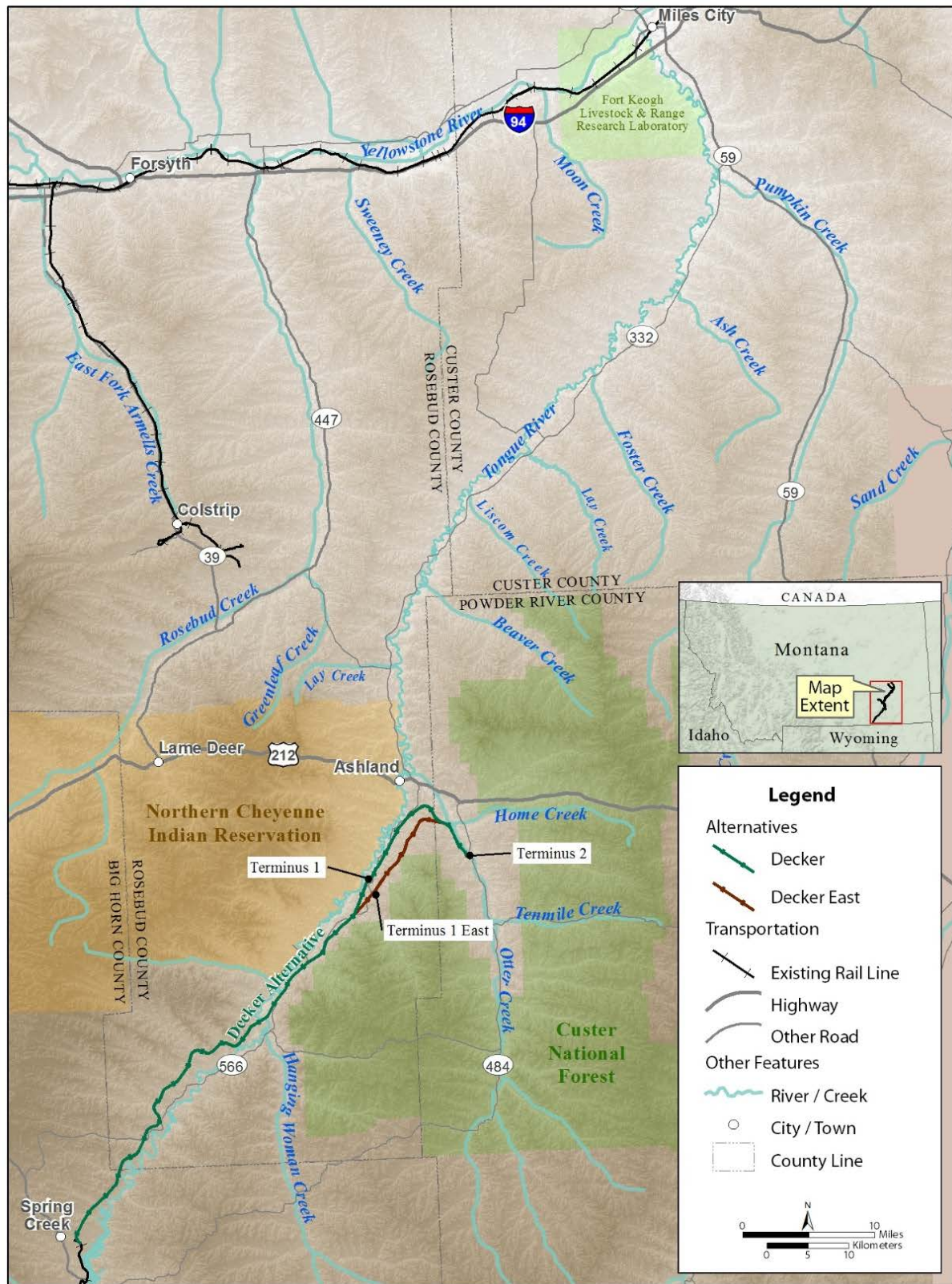


Table 9-9. Ashland, Montana to Spring Creek, Montana

						Change in Traffic, Trains per Day			
Segment 2, 49.7 miles, Westbound or Eastbound Main Tracks: 1 Traffic Control System: TWC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	0.0	0.0	0.0	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	0.0	0.0	0.0	0.0
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	0.0	0.0	0.0	0.0
	Maximum Change in Traffic	20	2030	High	High	26.4	26.4	0.0	26.4

This segment consists of the Tongue River Railroad Alternatives. Projected volume depends on construction of the proposed rail line so there is no current baseline volume and there would be no future volume if the railroad were not built.

As shown in Table 9-8, if a northern alternative were built, the train volume on this segment would range from 7.4 trains per day in to 18.2 trains per day. As shown in Table 9-9, if a southern alternative were built, the train volume would range from 0 to 26.4 per day.

Colstrip to Nichols, Montana

Table 9-10 summarizes projected train traffic for this segment, illustrated in Figure 9-5.

Figure 9-5. Colstrip to Nichols, Montana (29.7 miles)

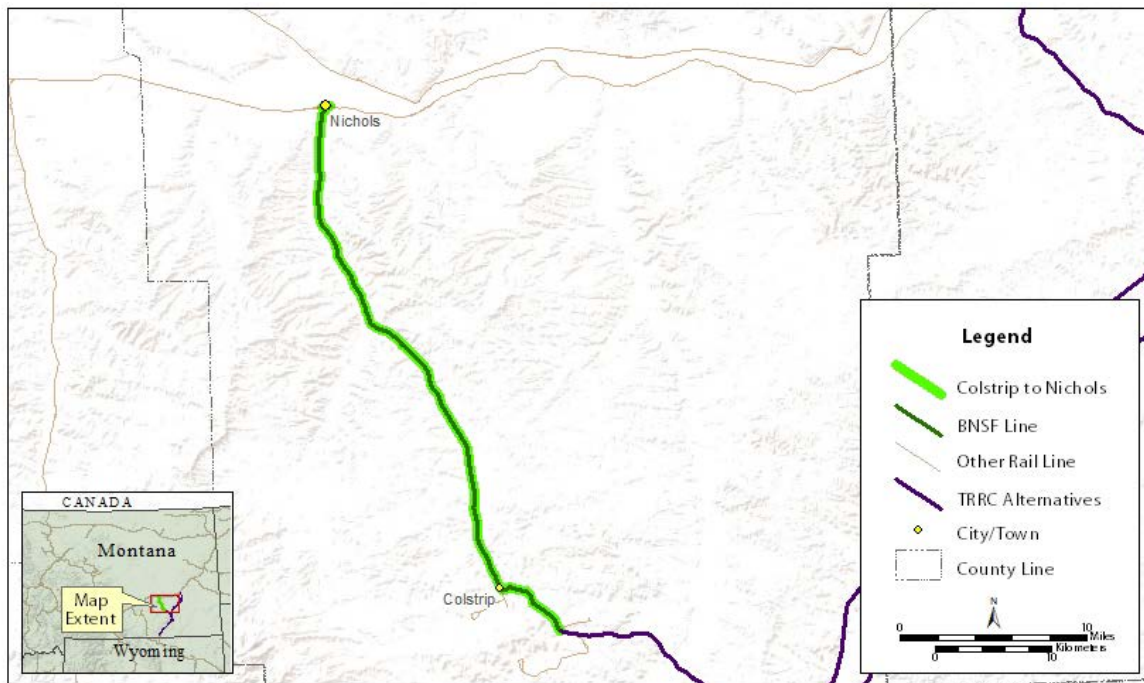


Table 9-10. Colstrip to Nichols, Montana: Projected Train Traffic for Year 2030

						Change in Traffic, Trains per Day			
Segment 3, 29.7 miles, Westbound or Eastbound Main Tracks: 1 Traffic Control System: ABS		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	12.8	7.4	5.4	7.4
	Maximum Change in Traffic	10	2037	High	Med	23.6	18.2	5.4	18.2
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	3.6	0.0	3.6	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	3.6	0.0	3.6	0.0

If one of the Colstrip Alternatives were built, all Tongue River trains would travel over the BNSF Colstrip Subdivision from Colstrip to Nichols (Figure 9-3). If a southern alternative were built, the proposed rail line would have no impact on this segment. As shown in Table 9-10, the change in trains would range from 7.4 to 18.2 trains per day if one of the northern alternatives were built.

From Nichols, trains would move east or west depending on the ultimate destination.

Nichols to Miles City, Montana

Table 9-11 summarizes projected train traffic for this segment, illustrated in Figure 9-6.

Figure 9-6. Nichols to Miles City, Montana (51.4 miles)

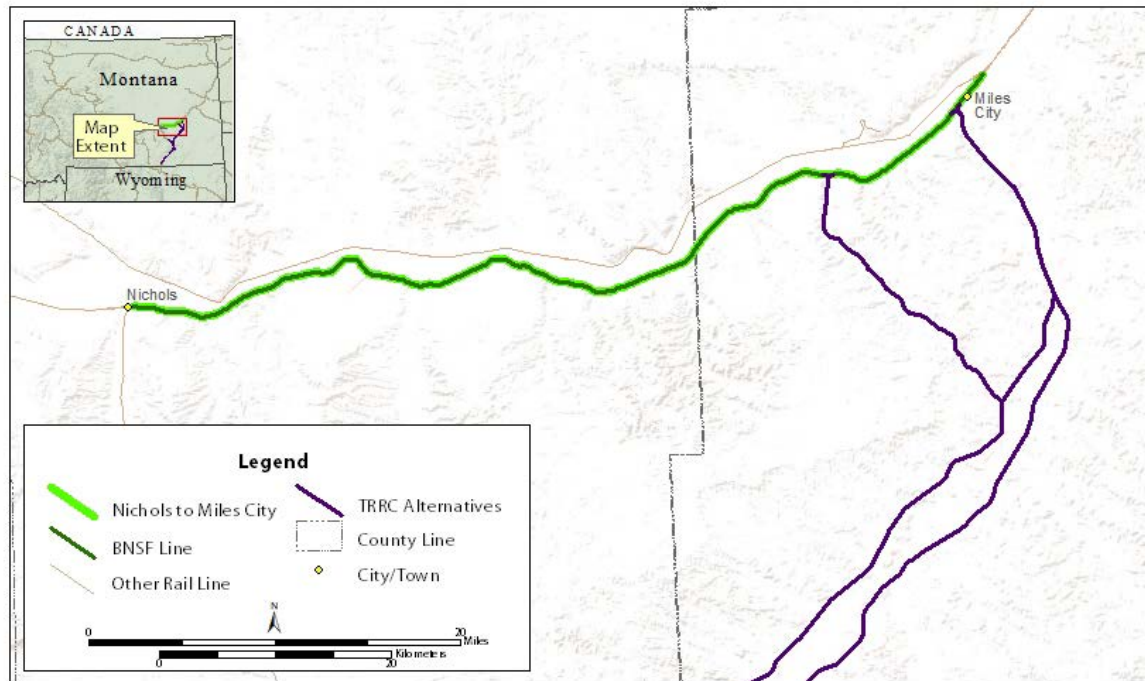


Table 9-11. Nichols to Miles City, Montana: Projected Train Traffic for Year 2030

Change in Traffic, Trains per Day									
Segment 4, 51.4 miles, Eastbound									
Main Tracks: 1									
Traffic Control System: CTC									
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2037	Low	Zero	43.5	7.4	42.9	0.5
	Maximum Change in Traffic	10	2037	High	Med	50.5	18.2	34.5	16.0
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	42.9	0.0	42.9	0.0
	Maximum Change in Traffic	19	2037	High	Med	43.5	9.7	34.5	9.0

Eastbound and westbound Tongue River trains from a northern alternative would diverge at Nichols. Eastbound trains would move on the Forsyth Subdivision toward Miles City, Montana (Figure 9.4). Westbound trains would move on the same subdivision toward

Huntley, Montana. If a southern alternative were built, eastbound Tongue River Railroad trains would also move over this segment by first moving west and north.

As shown in Table 9-11, if a northern alternative were built, the difference between the proposed rail line and No-Action Alternative for this segment would range from 0.5 to 16 additional trains per day. However, these trains would largely displace existing Powder River Basin trains moving to northern Midwest destinations and Powder River Basin trains to Chicago that move over other routes.

If a southern alternative were built, train volume would increase from 0 to 9 trains per day versus the No-Action Alternative. This is primarily the result of Tongue River trains displacing Powder River Basin trains moving to Chicago via other routes.

Huntley to Nichols, Montana

Table 9-12 summarizes projected train traffic for this segment, as illustrated in Figure 9-7.

Figure 9-7. Huntley to Nichols, Montana (84.5 miles)

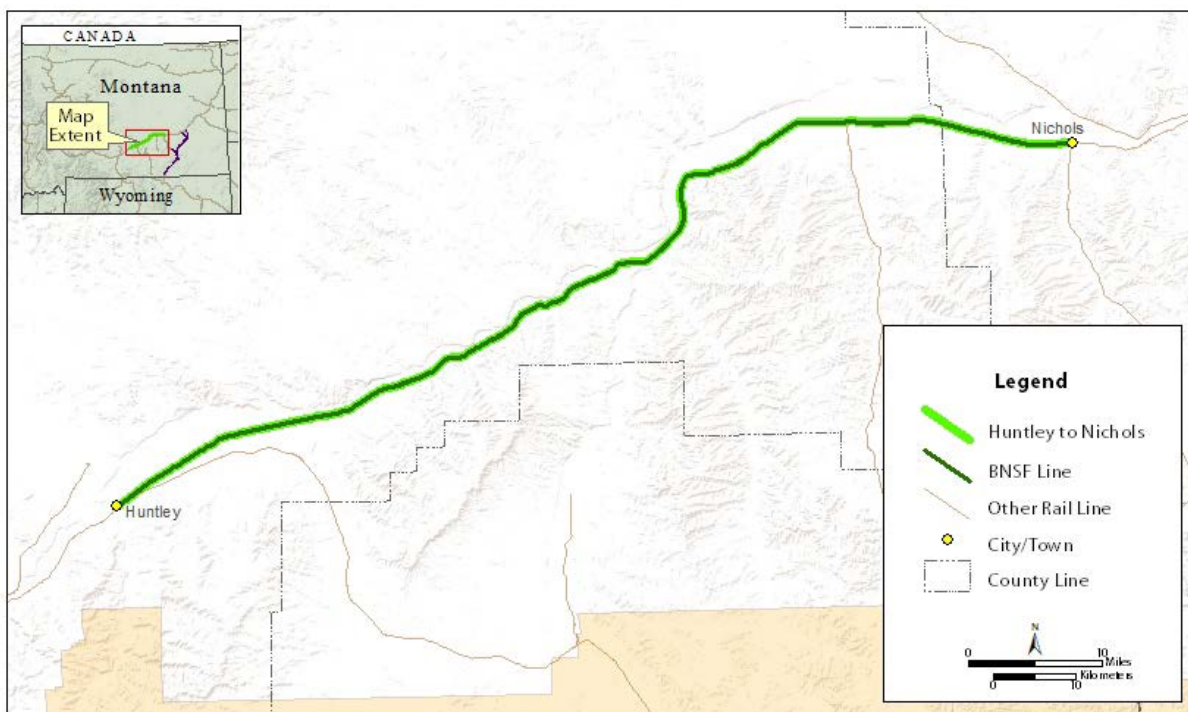


Table 9-12. Huntley to Nichols, Montana: Projected Train Traffic for Year 2030

						Change in Traffic, Trains per Day			
Segment 5, 84.5 miles, Westbound or Eastbound Main Tracks: 1 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	6	2037	Med	Zero	28.7	0.0	39.3	-10.6
	Maximum Change in Traffic	11	2023	High	High	29.3	7.4	24.0	5.3
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	39.3	0.0	39.3	0.0
	Maximum Change in Traffic	19	2037	High	Med	39.9	9.7	30.9	9.0

At Huntley, Montana, the BNSF Big Horn Subdivision connects with the Forsyth Subdivision (Figure 9-5). If a northern alternative were built, the change in trains per day over this segment would range from a decrease of 10.6 to an increase of 5.3 trains versus the No-Action Alternative. Under this scenario, Tongue River trains to northern Midwest destinations would displace existing Powder River Basin trains. The displaced Powder River Basin trains would move over this segment but the Tongue River trains would move east from Nichols and so would not move over this segment. Under the maximum change, Tongue River trains would move west over this segment toward West Coast ports.

If a southern alternative were built, the change in trains per day versus the No-Action Alternative would range from 0 to 9. Under the minimum change, the Tongue River trains would all move over this segment eastbound to northern Midwest destinations displacing Powder River Basin trains. The maximum change in traffic is driven by the growth of West Coast ports. Westbound Tongue River trains would move over this segment. Under the No-Action Alternative, new Powder River Basin trains would move to the West Coast instead.

Spring Creek, Montana, to Dutch, Wyoming

Table 9-13 summarizes projected train traffic for this segment, illustrated in Figure 9-8.

Figure 9-8. Spring Creek, Montana, to Dutch, Wyoming (22.6 miles)

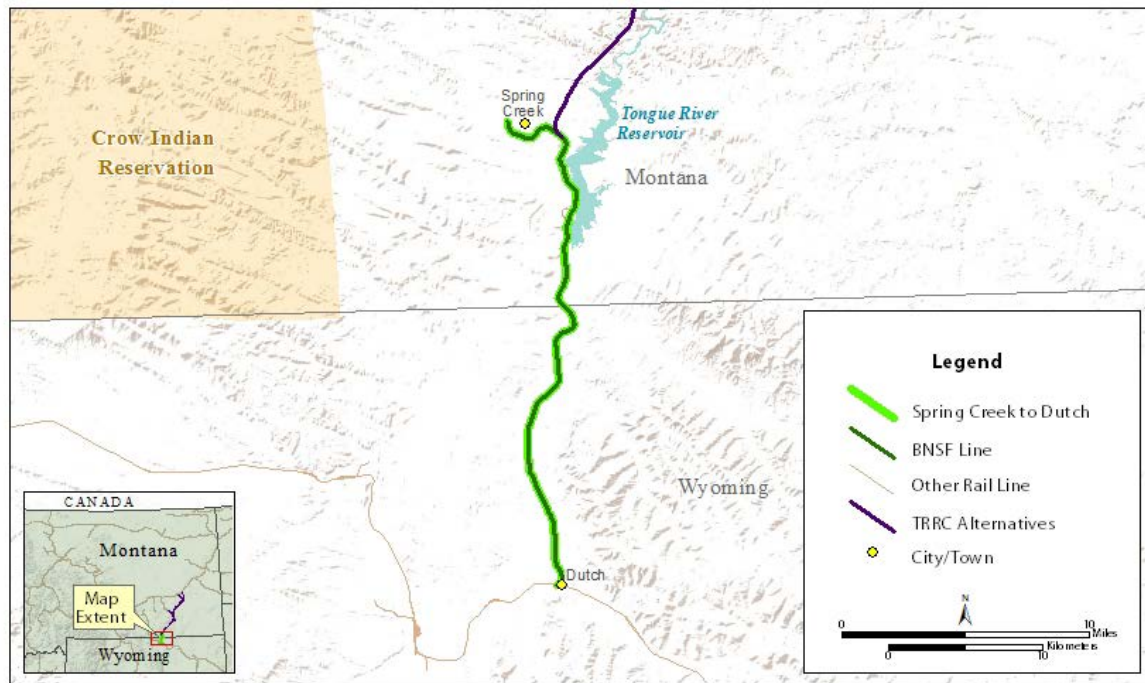


Table 9-13. Spring Creek, Montana, to Dutch, Wyoming

Segment 6, 22.6 miles, Westbound or Eastbound Main Tracks: 1 Traffic Control System: CTC		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	9	2023	High	Zero	11.8	0.0	16.5	-4.7
	Maximum Change in Traffic	11	2018	High	High	17.6	0.0	17.4	0.2
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	25.2	0.0	25.2	0.0
	Maximum Change in Traffic	20	2037	High	High	55.0	26.4	28.7	26.3

The southern alternatives would connect with the BNSF Dutch Subdivision at the existing Spring Creek rail spur. Montana Powder River Basin coal from Spring Creek also moves over this segment to Dutch, Wyoming.

As shown in Table 9-13, if a northern alternative were built no Tongue River trains would move over this segment. However, Tongue River trains moving over other segments would displace existing Powder River Basin trains moving over this segment resulting in a change

in train volume ranging from a decrease of 4.7 trains per day to an increase of 0.2 train per day.

If a southern alternative were built, the difference, versus the No-Action Alternative, would be from 0 to 26.3 trains per day. The minimum change would be with no port growth and all traffic moving east. In this case, Tongue River trains would displace Powder River Basin trains that mostly would not move over this segment. The maximum change would be driven by West Coast port growth, which would result in 26.3 additional Tongue River trains per day over this segment versus the No-Action Alternative. Tongue River trains would displace Powder River Basin trains most of which would not move over this segment.

From Dutch, southern alternative trains would diverge depending on destination. Trains to Superior, Wisconsin, and Stanton, North Dakota and all westbound trains would go north from Dutch to Huntley then east through Nichols and Miles City or west toward the coast. Trains to Chicago would go south from Dutch toward the Wyoming Powder River Basin.

Dutch, Wyoming, to Huntley, Montana

Table 9-14 summarizes projected train traffic for this segment, illustrated in Figure 9-9.

Figure 9-9. Dutch, Wyoming, to Huntley, Montana (135.6 miles)

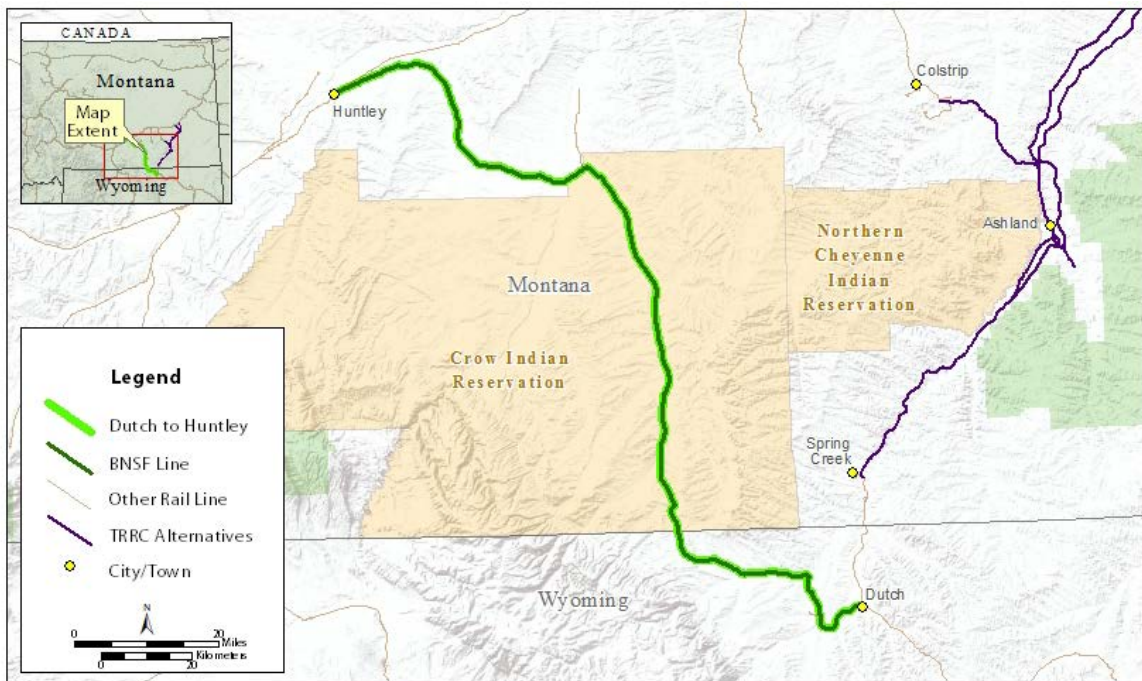


Table 9-14. Dutch, Wyoming, to Huntley, Montana

						Change in Traffic, Trains per Day			
Segment 7, 135.6 miles, Westbound or Eastbound Main Tracks: 2 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	6	2037	Med	Zero	18.2	0.0	28.8	-10.6
	Maximum Change in Traffic	7	2018	Med	Med	26.5	0.0	26.2	0.3
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	28.8	0.0	28.8	0.0
	Maximum Change in Traffic	19	2037	High	Med	49.1	9.7	40.1	9.0

At Dutch, Wyoming, the Dutch Subdivision connects with the BNSF Big Horn Subdivision to Huntley, Montana (Figure 9-7). As shown in Table 9-14, if a northern alternative were built no Tongue River trains would move over this segment. The difference in trains per day would range from 10.6 fewer to 0.3 more than the No-Action Alternative. Tongue River trains moving on other segments would displace existing Powder River Basin trains moving over this segment. The maximum change in traffic would be driven by West Coast port growth.

If a southern alternative were built, the minimum change in traffic between the proposed rail line and No-Action Alternative would be zero. The maximum change in traffic would be driven by West Coast port growth and high mine production resulting in 9 additional trains per day under the proposed rail line.

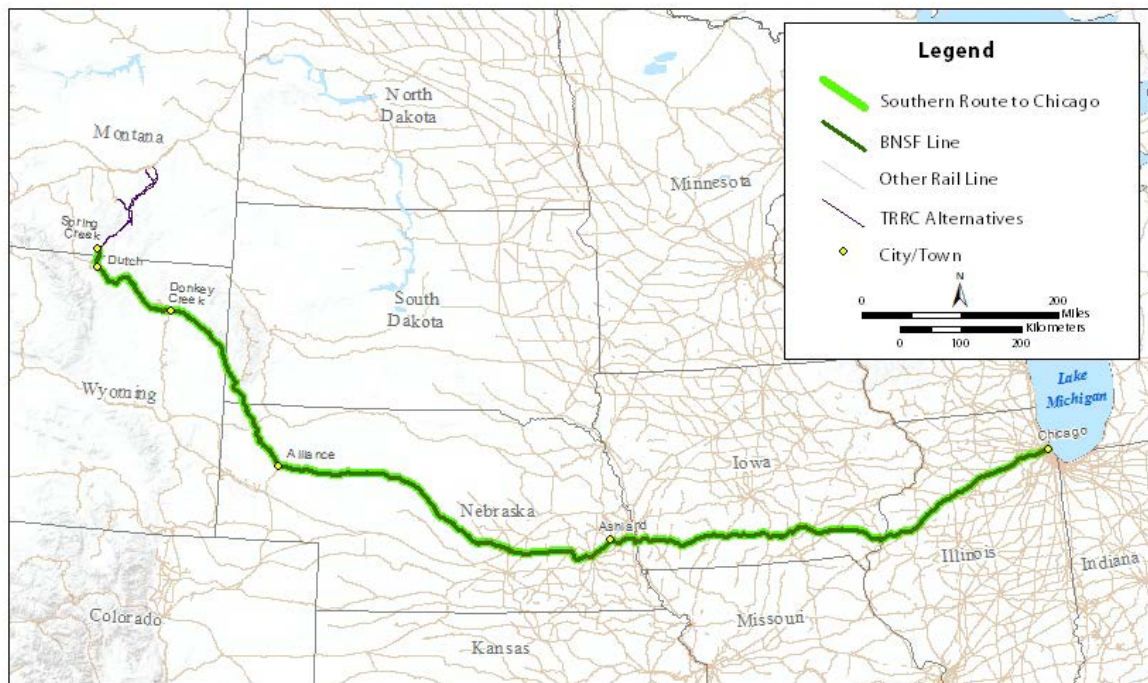
9.5.2.2 Eastbound Movements

The primary eastern destinations for Powder River Basin coal are interchanges with eastern railroads at Chicago, Illinois, the Port of Superior, Wisconsin, and plants in North Dakota, Wisconsin, and Minnesota.

Southern Route to Chicago

The southern alternatives would connect with BNSF carrying traffic from Dutch, Wyoming, to Chicago, Illinois. The segments of this route are described below and shown in Figure 9-10.

Figure 9-10. Southern Route to Chicago



Dutch to Donkey Creek, Wyoming

Table 9-15 summarizes projected train traffic for this segment.

Table 9-15. Dutch to Donkey Creek, Wyoming

Dutch to Donkey Creek, Wyoming						Change in Traffic, Trains per Day			
Segment 9, 104.2 miles, Eastbound						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 2		Traffic Control System: CTC	Scenario	Year	Mine Production	Terminal Growth	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic		11	2023	High	High	52.8	0.0	62.0
	Maximum Change in Traffic		6	2030	Med	Zero	50.8	0.0	41.9
Southern Alternatives	Minimum Change in Traffic		20	2037	High	High	51.6	1.1	66.8
	Maximum Change in Traffic		19	2037	High	Med	59.8	15.4	44.8

As shown in Table 9-15 if a northern alternative were built, the proposed rail line would result in 9.2 fewer to 8.9 more trains per day than under the No-Action Alternative. This would be driven by a high port growth scenario under which coal trains would move mostly to West Coast ports and some Powder River Basin coal would be displaced by Tongue River

coal. Tongue River westbound trains from a northern alternative would not move over this segment, which would handle only eastbound and Powder River Basin traffic,

If a southern alternative were built, the proposed rail line would result in a minimum of 15.2 fewer trains per day and a maximum of 15.1 additional trains per day versus the No-Action Alternative. The minimum would occur under high port growth as Tongue River traffic and some Powder River Basin coal moves west instead of east. The maximum scenario results from Tongue River coal displacing some Powder River Basin coal that would not move over this segment.

Thunder Junction to Donkey Creek, Wyoming

Table 9-16 summarizes projected train traffic for this segment.

Table 9-16. Thunder Junction to Donkey Creek, Wyoming

						Change in Traffic, Trains per Day			
Segment 14, 43.8 miles, Eastbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario		Year	Mine Production	Terminal Growth					
Northern Alternatives	Minimum Change in Traffic	11	2037	High	High	98.2	0.0	106.7	-8.4
	Maximum Change in Traffic	5	2030	Low	High	100.4	0.0	98.1	2.2
Southern Alternatives	Minimum Change in Traffic	20	2037	High	High	90.8	0.0	106.7	-15.9
	Maximum Change in Traffic	14	2030	Low	High	100.0	0.0	98.1	1.8

As shown in Table 9-16, Tongue River trains would not move over this segment under either a northern or southern alternative. If a northern alternative were built, the proposed rail line would result in 8.4 trains per day fewer to 2.2 trains per day more than under the No-Action Alternative. If a southern alternative were built, the proposed rail line would result in 15.9 trains per day fewer to 1.8 trains per day more than under the No-Action Alternative. The change in traffic would be driven by port growth in which Tongue River trains would displace some Powder River Basin trains moving over this segment.

Thunder Junction, Wyoming, to Alliance, Nebraska

Table 9-17 summarizes projected train traffic for this segment.

Table 9-17. Thunder Junction, Wyoming, to Alliance, Nebraska: Projected Train Traffic for Year 2030

						Change in Traffic, Trains per Day			
Segment 13, 256.2 miles, Eastbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	10	2037	High	Med	65.6	0.0	80.7	-15.2
	Maximum Change in Traffic	11	2030	High	High	57.9	0.0	57.3	0.6
Southern Alternatives	Minimum Change in Traffic	19	2037	High	Med	57.0	0.0	80.7	-23.8
	Maximum Change in Traffic	20	2023	High	High	46.6	0.0	43.8	2.8

Tongue River trains would not move over this segment under either a northern or a southern alternative. If a northern alternative were built, the proposed rail line would result in 15.9 trains per day fewer to 0.6 train per day more than under the No-Action Alternative. If a southern alternative were built, the proposed rail line would result in 23.8 trains per day fewer to 2.8 trains per day more than under the No-Action Alternative. The change in traffic would be driven by port growth in which Tongue River trains would displace some Powder River Basin trains moving over this segment.

Donkey Creek, Wyoming, to Edgemont, South Dakota

Table 9-18 summarizes projected train traffic for this segment.

Table 9-18. Donkey Creek, Wyoming, to Edgemont, South Dakota

						Change in Traffic, Trains per Day			
Segment 10, 111.3 miles, Eastbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	55.2	0.0	65.4	-10.2
	Maximum Change in Traffic	6	2037	Med	Zero	79.6	0.0	72.9	6.7
Southern Alternatives	Minimum Change in Traffic	20	2023	High	High	61.4	1.0	72.2	-10.8
	Maximum Change in Traffic	19	2037	High	Med	80.2	15.4	64.9	15.4

As shown in Table 9-18, if a northern alternative were built no Tongue River trains would move over this segment. The difference between the proposed rail line and the No-Action Alternative would range from 10.2 trains per day fewer to 6.7 trains per day more under a northern alternative and 10.8 trains per day fewer to 15.4 trains per day more if a southern alternative were built.

Edgemont, South Dakota to Crawford, Nebraska

Table 9-19 summarizes projected train traffic for this segment.

Table 9-19. Edgemont, South Dakota to Crawford, Nebraska

Segment 11, 55 miles, Eastbound		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	64.9	0.0	75.1	-10.2
	Maximum Change in Traffic	6	2037	Med	Zero	92.2	0.0	85.5	6.7
Southern Alternatives	Minimum Change in Traffic	20	2023	High	High	71.0	1.0	81.8	-10.8
	Maximum Change in Traffic	19	2037	High	Med	92.8	15.4	77.5	15.4

As shown in Table 9-19, if a northern alternative were built no Tongue River trains would move over this segment. The difference between the proposed rail line and the No-Action Alternative would range from 10.2 trains per day fewer to 6.7 trains per day more under a northern alternative and 10.8 trains per day fewer to 15.4 trains per day more if a southern alternative were built.

Crawford, Nebraska to Alliance, Nebraska

Table 9-20 summarizes projected train traffic for this segment.

Table 9-20. Crawford, Nebraska to Alliance, Nebraska

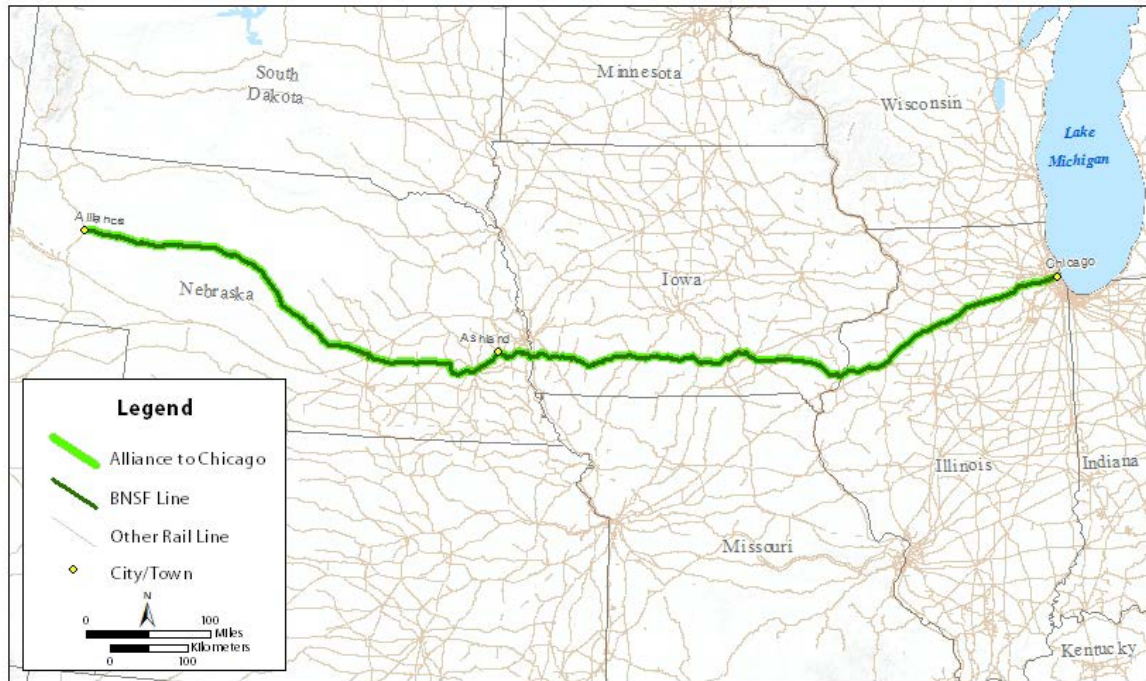
						Change in Traffic, Trains per Day			
Segment 12, 56.5 miles, Eastbound Main Tracks: 2 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	52.4	0.0	62.6	-10.2
	Maximum Change in Traffic	6	2037	Med	Zero	76.0	0.0	69.3	6.7
Southern Alternatives	Minimum Change in Traffic	20	2023	High	High	58.6	1.0	69.4	-10.8
	Maximum Change in Traffic	19	2037	High	Med	76.6	15.4	61.3	15.4

As shown in Table 9-20, if a northern alternative were built no Tongue River trains would move over this segment. The difference between the proposed rail line and the No-Action Alternative would range from 10.2 trains per day fewer to 6.7 trains per day more under a northern alternative and 10.8 trains per day fewer to 15.4 trains per day more if a southern alternative were built.

Alliance, Nebraska, to Chicago, Illinois

At Alliance, Nebraska, the line from Dutch joins the line from the southern Wyoming Powder River Basin. All Powder River Basin trains heading to Chicago move over this line, which comprises the BNSF Sand Hills, Ravenna, Creston, Ottumwa, Mendota and Chicago Subdivisions (Figure 9-11). Segments of this route are discussed in more detail below.

Figure 9-11. Alliance, Nebraska, to Chicago, Illinois (928.9 miles)



Alliance to Ashland, Nebraska

Table 9-21 summarizes projected train traffic for this segment.

Table 9-21. Alliance to Ashland, Nebraska: Projected Train Traffic for Year 2030

						Change in Traffic, Trains per Day			
Segment 15, 388.8 miles, Eastbound Main Tracks: 2,3 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2037	High	Med	66.8	0.0	81.9	-15.2
	Maximum Change in Traffic	3	2037	Low	Zero	72.8	0.0	72.9	-0.1
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	73.4	0.0	82.0	-8.6
	Maximum Change in Traffic	15	2037	Med	Zero	73.1	2.1	72.9	0.2

As shown in Table 9-21, if a northern alternative were built, Tongue River trains would not move over this segment. Under a northern alternative, there would be 15.2 to 0.1 fewer trains per day under the proposed rail line versus the No-Action Alternative. If a southern alternative were built, the differences between the proposed rail line and the No-Action

Alternative would range from 8.6 fewer trains per day to 0.2 train per day more. Tongue River trains moving over other segments would displace Powder River Basin trains moving over this segment.

Ashland, Nebraska, to Aurora, Illinois

Table 9-22 summarizes projected train traffic for this segment.

Table 9-22. Ashland, Nebraska, to Aurora, Illinois

		Change in Traffic, Trains per Day							
Segment 30, 512.1 miles, Eastbound		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 2,3	Traffic Control System: CTC								
Northern Alternatives	Minimum Change in Traffic	9	2023	High	Zero	32.6	0.0	40.1	-7.5
	Maximum Change in Traffic	11	2018	High	High	35.6	0.0	35.3	0.4
Southern Alternatives	Minimum Change in Traffic	18	2018	High	Zero	35.6	4.7	35.9	-0.3
	Maximum Change in Traffic	20	2018	High	High	35.7	1.9	35.3	0.5

As shown in Table 9-22, if a northern alternative were built, no Tongue River trains would move over this segment. The differences between the proposed rail line and the No-Action Alternative would range from 7.5 trains per day fewer to 0.4 train per day more. If a southern alternative were built, there would be 0.3 fewer trains per day to 0.5 train per day more under the proposed rail line. Tongue River trains moving over other segments would displace Powder River Basin trains moving over this segment.

Aurora to Chicago Cicero, Illinois

Table 9-23 summarizes projected train traffic for this segment.

Table 9-23 Aurora to Chicago Cicero, Illinois

						Change in Traffic, Trains per Day			
Segment 25, 28 miles, Eastbound Main Tracks: 3 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	118.5	0.0	118.5	0.0
	Maximum Change in Traffic	9	2023	High	Zero	142.4	7.3	135.1	7.3
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	118.5	0.0	118.5	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	118.5	0.0	118.5	0.0

All coal trains from either Tongue River or Powder River Basin origins destined for interchange to eastern railroads at Chicago would move over this segment. Table 9-23 shows there would little difference between the proposed rail line and the No-Action Alternative on this segment. There would be a maximum of 7.3 additional trains per day under the proposed rail line if a northern alternative were built.

Ashland, Nebraska, to Willmar, Minnesota

Table 9-24 summarizes projected train traffic for this segment.

Table 9-24. Ashland, Nebraska, to Willmar, Minnesota

						Change in Traffic, Trains per Day			
Segment 19, 330.6 miles, Eastbound Main Tracks: 1 Traffic Control System: TWC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2037	High	Med	13.1	0.0	21.7	-8.6
	Maximum Change in Traffic	6	2037	Med	Zero	13.2	0.0	13.1	0.1
Southern Alternatives	Minimum Change in Traffic	19	2037	High	Med	13.0	0.0	21.7	-8.6
	Maximum Change in Traffic	18	2023	High	Zero	10.4	0.0	10.2	0.2

As shown in Table 9-24, under the proposed rail line, there would be 8.6 fewer to 0.2 trains more per day than under the No-Action Alternative scenarios. No Tongue River trains would

move over this segment. The differences under the proposed rail line would result from Tongue River trains displacing some Powder River Basin trains.

Willmar to St. Paul, Minnesota

Table 9-25 summarizes projected train traffic for this segment.

Table 9-25. Willmar to St. Paul, Minnesota

Change in Traffic, Trains per Day									
Segment 21, 100.5 miles, Eastbound						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 1		Scenario	Year	Mine Production	Terminal Growth				
Traffic Control System: CTC/ABS									
Northern Alternatives	Minimum Change in Traffic	4	2023	Low	Med	17.8	7.4	17.9	-0.1
	Maximum Change in Traffic	9	2023	High	Zero	25.5	15.8	17.3	8.2
Southern Alternatives	Minimum Change in Traffic	18	2037	High	Zero	20.2	8.9	20.8	-0.5
	Maximum Change in Traffic	18	2023	High	Zero	18.1	8.3	17.3	0.8

As shown in Table 9-25, if a northern alternative were built, the proposed rail line would result in 0.1 fewer to 8.2 trains more than under the No-Action Alternative. The maximum 8.2 additional trains per day would be driven by Tongue River trains to Chicago displacing Powder River Basin trains that would not move over this segment. If a southern alternative were built, there would be little difference between the proposed rail line and the No-Action Alternative because Tongue River trains would displace Powder River Basin trains moving over this same segment to Superior, Wisconsin, and other northern Midwest points.

St. Paul, Minnesota, to Boylston, Wisconsin

Table 9-26 summarizes projected train traffic for this segment.

Table 9-26. St. Paul, Minnesota, to Boylston, Wisconsin

		Change in Traffic, Trains per Day							
Segment 26, 146.3 miles, Eastbound		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 1	Traffic Control System: ABS								
Northern Alternatives	Minimum Change in Traffic	7	2030	Med	Med	16.2	0.0	16.3	-0.1
	Maximum Change in Traffic	6	2037	Med	Zero	18.3	0.0	18.2	0.1
Southern Alternatives	Minimum Change in Traffic	18	2037	High	Zero	17.3	0.0	18.2	-0.9
	Maximum Change in Traffic	18	2023	High	Zero	14.3	0.0	14.0	0.2

As shown in Table 9-26, there would be little difference in daily trains between the proposed rail line and the No-Action Alternative because only trains headed for Superior, Wisconsin, would move over this segment. Tongue River trains would displace Powder River Basin trains.

Boylston to Superior, Wisconsin

Table 9-27 summarizes projected train traffic for this segment.

Table 9-27. Boylston to Superior, Wisconsin

		Change in Traffic, Trains per Day							
Segment 27, 8.8 miles, Eastbound		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 2	Traffic Control System: CTC								
Northern Alternatives	Minimum Change in Traffic	7	2030	Med	Med	15.4	0.0	15.5	-0.1
	Maximum Change in Traffic	6	2037	Med	Zero	17.4	0.0	17.3	0.1
Southern Alternatives	Minimum Change in Traffic	18	2037	High	Zero	16.4	0.0	17.3	-0.9
	Maximum Change in Traffic	18	2023	High	Zero	13.6	0.0	13.4	0.2

As shown in Table 9-27, there would be little difference in daily trains between the proposed rail line and the No-Action Alternative because only trains headed for Superior, Wisconsin,

would move over this segment. Tongue River trains would displace Powder River Basin trains.

Boylston, Wisconsin, to Carlton, Minnesota

Table 9-28 summarizes projected train traffic for this segment.

Table 9-28. Boylston, Wisconsin, to Carlton, Minnesota

						Change in Traffic, Trains per Day			
Segment 28, 20.1 miles, Eastbound						Total with			Change
Main Tracks: 1						Proposed	Proposed	No	in
Traffic Control System: CTC						Action	Action	Action	Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	13.3	0.0	13.3	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	13.3	0.0	13.3	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	13.3	0.0	13.3	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	13.3	0.0	13.3	0.0

Only trains moving from the Powder River Basin to Cohasset, Minnesota, would use this segment. As shown in Table 9-28, there would be no difference between the proposed rail line and the No-Action Alternative for this segment. Tongue River trains would displace Powder River Basin trains moving to Cohasset.

Carlton to Cohasset, Minnesota

Table 9-29 summarizes projected train traffic for this segment.

Table 9-29. Carlton to Cohasset, Minnesota

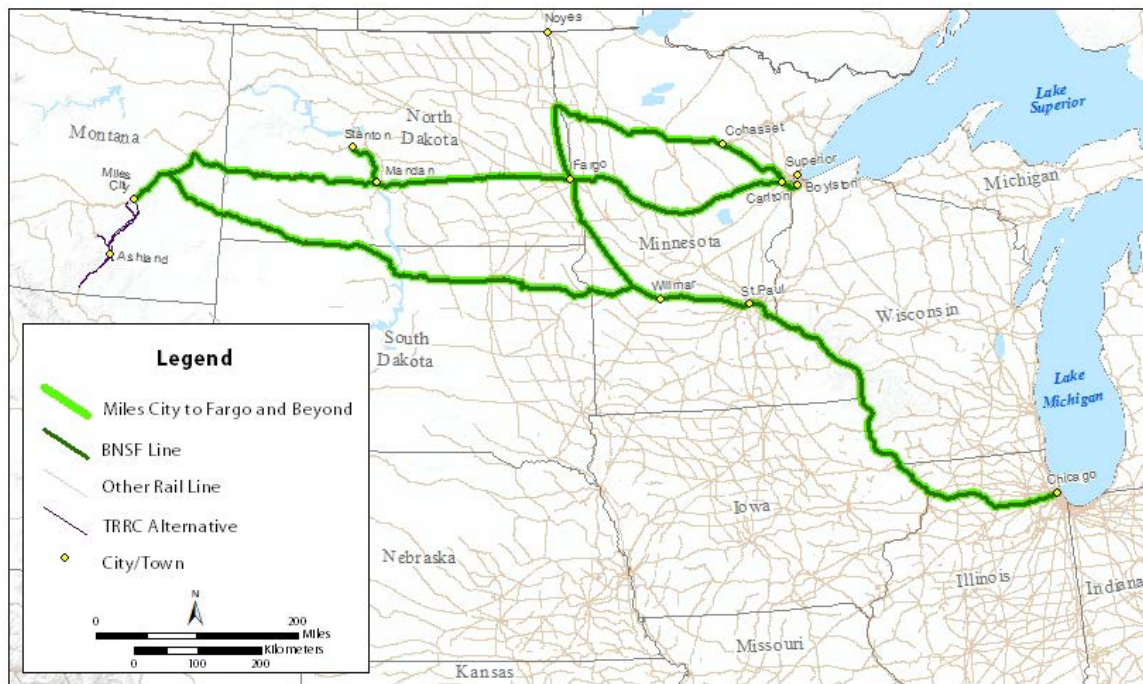
						Change in Traffic, Trains per Day			
Segment 29, 81.4 miles, Eastbound						Total with			Change
Main Tracks: 1				Mine	Terminal	Proposed	Proposed	No	in
Traffic Control System: CTC		Scenario	Year	Production	Growth	Action	Action	Action	Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	7.3	0.0	7.3	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	7.3	0.0	7.3	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	7.3	0.0	7.3	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	7.3	0.0	7.3	0.0

As with the segment from Boylston to Carlton, Minnesota, only trains moving from the Powder River Basin to Cohasset, Minnesota would use this segment. As shown in Table 9-29, there would be no difference between the proposed rail line and the No-Action Alternative for this segment. Tongue River trains would displace Powder River Basin trains moving to Cohasset.

Northern Route to Chicago

The northern route to Chicago via St. Paul, and the northern route to Lake Superior ports via Fargo, North Dakota, are described below and shown in Figure 9-12.

Figure 9-12. Miles City, Montana to Fargo, North Dakota (561.8 miles) and Beyond to Cohasset and Superior



Miles City to Glendive, Montana

Table 9-30 summarizes projected train traffic for this segment.

Table 9-30. Miles City to Glendive, Montana

						Change in Traffic, Trains per Day			
Segment 16, 78.6 miles, Eastbound						Total with			
Main Tracks: 1						Proposed	Proposed	No	Change
Traffic Control System: ABS						Action	Action	Action	Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	3	2037	Low	Zero	43.5	7.4	42.9	0.5
	Maximum Change in Traffic	10	2037	High	Med	50.5	18.2	34.5	16.0
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	42.9	0.0	42.9	0.0
	Maximum Change in Traffic	19	2037	High	Med	43.5	9.7	34.5	9.0

All Tongue River Railroad trains destined to Upper Midwest markets would move over this segment. The BNSF Forsyth Subdivision links Miles City with Glendive, Montana. As shown in Table 9-30, the difference between the proposed rail line and the No-Action

Alternative would range from 0.5 to 16 additional trains per day if a northern alternative were built and 0 to 9 additional trains per day if a southern alternative were built. Tongue River trains would move over this segment to reach Upper Midwest destinations displacing Powder River Basin trains, some of which would move over other segments to these destinations.

Glendive, Montana to Mandan, North Dakota

Table 9-31 summarizes projected train traffic for this segment.

Table 9-31. Glendive, Montana to Mandan, North Dakota

						Change in Traffic, Trains per Day			
Segment 17, 284.6 miles, Eastbound						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 1	Traffic Control System: ABS	Scenario	Year	Mine Production	Terminal Growth				
Northern Alternatives	Minimum Change in Traffic	3	2037	Low	Zero	34.4	7.4	33.9	0.5
	Maximum Change in Traffic	10	2037	High	Med	41.5	18.2	25.5	16.0
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	33.9	0.0	33.9	0.0
	Maximum Change in Traffic	19	2037	High	Med	34.5	9.7	25.5	9.0

All Tongue River Railroad trains destined for Upper Midwest markets would move over this segment. The BNSF Dickinson Subdivision links Glendive with Mandan, North Dakota. As shown in Table 9-31, the difference between the proposed rail line and the No-Action Alternative would range from 0.5 to 16 additional trains per day if a northern alternative were built and 0 to 9 additional trains per day if a southern alternative were built. Tongue River trains would move over this segment to reach Upper Midwest destinations displacing Powder River Basin trains, some of which would move over other segments to these destinations.

Stanton trains split off at Mandan. At Fargo, trains split off south and east toward St. Paul and Chicago or north and east toward Cohasset and Superior.

Mandan to Stanton, North Dakota

Table 9-32 summarizes projected train traffic for this segment.

Table 9-32. Mandan to Stanton, North Dakota

						Change in Traffic, Trains per Day			
Segment 22, 53.5 miles, Eastbound						Total with			Change
Main Tracks: 1						Proposed	Proposed	No	in
Traffic Control System: TWC						Action	Action	Action	Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	3.6	0.0	3.6	0.0
	Maximum Change in Traffic	6	2037	Med	Zero	5.2	0.3	5.2	0.0
Southern Alternatives	Minimum Change in Traffic	18	2018	High	Zero	3.6	0.0	3.6	0.0
	Maximum Change in Traffic	16	2030	Med	Zero	4.7	0.3	4.7	0.0

This segment is a relatively lightly used branch line. All Tongue River and Powder River Basin trains would move over this segment to reach Stanton. As shown in Table 9-32, there would be no difference between the proposed rail line and the No-Action Alternative.

Mandan to Fargo, North Dakota

Table 9-33 summarizes projected train traffic for this segment.

Table 9-33. Mandan to Fargo, North Dakota

						Change in Traffic, Trains per Day			
Segment 18, 198.6 miles, Eastbound						Total with			Change
Main Tracks: 1						Proposed	Proposed	No	in
Traffic Control System: ABS						Action	Action	Action	Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	3	2037	Low	Zero	32.8	7.4	32.3	0.5
	Maximum Change in Traffic	10	2037	High	Med	39.9	17.9	23.9	16.0
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	32.3	0.0	32.3	0.0
	Maximum Change in Traffic	19	2037	High	Med	32.9	9.3	23.9	9.0

The BNSF Jamestown Subdivision links Mandan with Fargo. As shown in Table 9-33, the difference between the proposed rail line and the No-Action Alternative would range from 0.5 to 16 additional trains per day if a northern alternative were built and 0 to 9 additional

trains per day if a southern alternative were built. Tongue River trains would move over this segment to reach Upper Midwest destinations displacing Powder River Basin trains, some of which would move over other segments to upper Midwest destinations.

Fargo, North Dakota, to Willmar, Minnesota

Table 9-34 summarizes projected train traffic for this segment.

Table 9-34. Fargo, North Dakota, to Willmar, Minnesota

						Change in Traffic, Trains per Day			
Segment 20, 158.5 miles, Eastbound Main Tracks: 1 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	3	2037	Low	Zero	19.6	7.4	19.1	0.5
	Maximum Change in Traffic	10	2037	High	Med	26.5	15.8	10.8	15.8
Southern Alternatives	Minimum Change in Traffic	12	2037	Low	Zero	19.1	0.0	19.1	0.0
	Maximum Change in Traffic	20	2037	High	High	19.7	8.9	10.8	8.9

As shown in Table 9-34, the proposed rail line would result in 0.5 to 15.8 additional trains per day if a northern alternative were built and 0 to 8.9 additional trains per day if a southern alternative were built. The increases would be driven by Tongue River trains to Chicago displacing Powder River Basin trains that would move to Chicago via Alliance and Ashland, Nebraska.

St. Paul, Minnesota, to N La Crosse, Wisconsin

Table 9-35 summarizes projected train traffic for this segment.

Table 9-35. St. Paul, Minnesota, to N La Crosse, Wisconsin

						Change in Traffic, Trains per Day			
Segment 23, 128.8 miles, Eastbound						Total with			
Main Tracks: 2						Propose	Proposed	No	Change
Traffic Control System: CTC						d Action	Action	Action	in
		Scenario	Year	Mine Production	Terminal Growth				Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	36.3	0.0	36.3	0.0
	Maximum Change in Traffic	9	2023	High	Zero	48.7	7.3	41.4	7.3
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	36.3	0.0	36.3	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	36.3	0.0	36.3	0.0

This segment is heavily used. In addition to general freight, BNSF intermodal and an increasing number of crude oil trains move over this route to Chicago. As shown in Table 9-35, if the northern alternative were built the proposed rail line would result in 0 to 7.3 more trains per day than the No-Action Alternative. There would be no difference between the proposed rail line and the No-Action Alternative if the southern alternative were built. The difference in daily trains under the northern alternative would be driven by Tongue River trains to Chicago displacing Powder River Basin trains that would move to Chicago via other routes.

N La Crosse, Wisconsin, to Aurora, Illinois

Table 9-36 summarizes projected train traffic for this segment.

Table 9-36. N La Crosse, Wisconsin, to Aurora, Illinois

Segment 24, 263.5 miles, Eastbound Main Tracks: 1,2 Traffic Control System: CTC/ABS		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	35.1	0.0	35.1	0.0
	Maximum Change in Traffic	9	2023	High	Zero	47.3	7.3	40.0	7.3
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	35.1	0.0	35.1	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	35.1	0.0	35.1	0.0

This segment is heavily used. In addition to general freight, BNSF intermodal and an increasing number of crude oil trains move over this route to Chicago. As shown in Table 9-36, if the northern alternative were built the proposed rail line would result in 0 to 7.3 more trains per day than the No-Action Alternative. There would be no difference between the proposed rail line and the No-Action Alternative if a southern alternative were built. The difference in daily trains under the northern alternatives would be driven by Tongue River trains to Chicago displacing Powder River Basin trains that would move to Chicago via other routes.

Fargo, North Dakota, to Carlton, Minnesota

Table 9-37 summarizes projected train traffic for this segment.

Table 9-37. Fargo, North Dakota, to Carlton, Minnesota

Segment 31, 230.2 miles, Eastbound Main Tracks: 1,2 Traffic Control System: TWC, CTC		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	24.8	0.0	24.8	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	24.8	0.0	24.8	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	24.8	0.0	24.8	0.0
	Maximum Change in Traffic	18	2037	High	Zero	38.1	0.8	36.9	1.2

As shown in Table 9-37, there would be little difference in trains per day between the proposed rail line and the No-Action Alternative on this segment. Both Tongue River and Powder River Basin trains would use this segment to reach Superior, Wisconsin, and projected volume is small.

Carlton, Minnesota, to Superior, Wisconsin

Table 9-38 summarizes projected train traffic for this segment.

Table 9-38. Carlton, Minnesota, to Superior, Wisconsin

						Change in Traffic, Trains per Day			
Segment 32, 28.9 miles, Eastbound Main Tracks: 1,2 Traffic Control System: TWC, CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	13.3	0.0	13.3	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	13.3	0.0	13.3	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	13.3	0.0	13.3	0.0
	Maximum Change in Traffic	18	2037	High	Zero	21.0	0.8	19.8	1.2

As shown in Table 9-38, there would be little difference in trains per day between the proposed rail line and the No-Action Alternative for this segment, because both Tongue River and Powder River Basin trains would use this segment to reach Superior, Wisconsin.

Fargo, North Dakota, to Cohasset, Minnesota

Table 9-39 summarizes projected train traffic for this segment.

Table 9-39. Fargo, North Dakota, to Cohasset, Minnesota

Segment 33, 260.8 miles, Eastbound Main Tracks: 1 Traffic Control System: ABS, TWC		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2023	Low	Zero	9.5	0.0	9.6	0.0
	Maximum Change in Traffic	11	2018	High	High	8.7	2.0	8.4	0.4
Southern Alternatives	Minimum Change in Traffic	18	2037	High	Zero	12.0	0.0	12.0	-0.1
	Maximum Change in Traffic	19	2023	High	Med	9.6	1.9	9.4	0.2

As shown in Table 9-39, there would be little difference in trains per day between the proposed rail line and the No-Action Alternative for this segment.

9.5.2.3 Westbound Movements

Projected westbound volume is driven by projected growth in export capacity at Pacific Northwest ports. If port capacity were built, the capacity would be filled with export coal. If the Tongue River Railroad were built, then some of the export coal would come from Tongue River. If Tongue River were not built then Powder River Basin coal would fill the export capacity. As shown in Tables 9-40 through 9-56, there would be little difference between the proposed rail line and the No-Action Alternative for any segment west of Huntley.

Huntley to Mossmain, Montana

Table 9-40 summarizes projected train traffic for this segment, illustrated in Figure 9-13.

Figure 9-13. Huntley to Mossmain, Montana (23.1 miles)

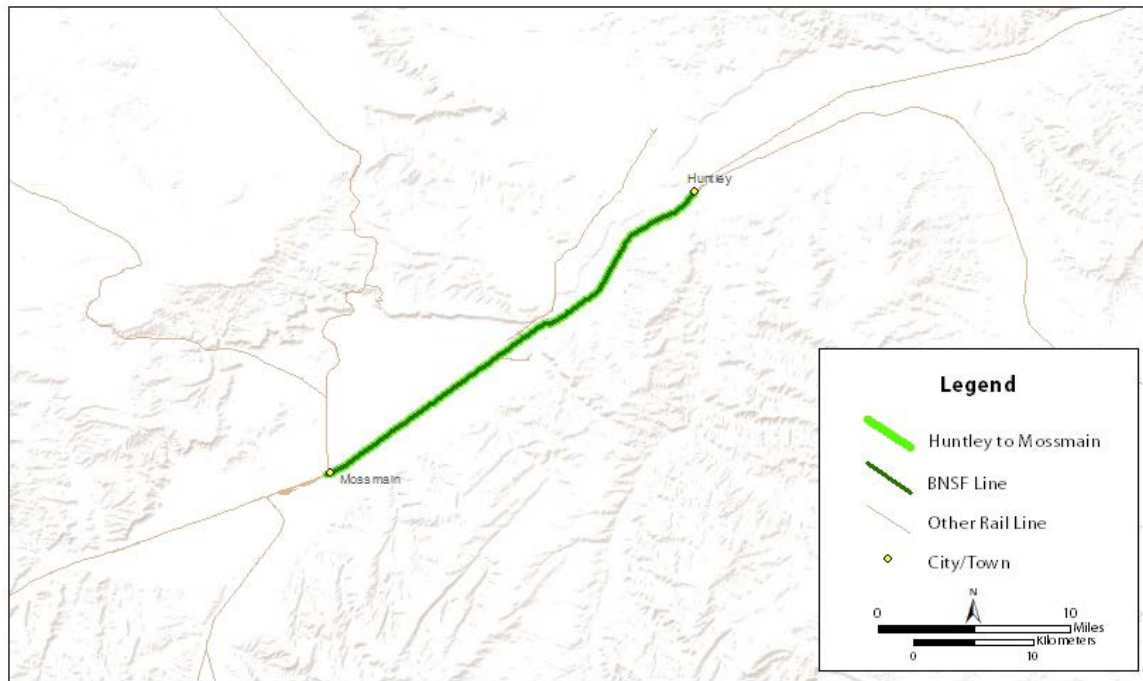


Table 9-40. Huntley to Mossmain, Montana

						Change in Traffic, Trains per Day			
Segment 34, 23.1 miles, Westbound						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 1									
Traffic Control System: ABS									
		Scenario	Year	Mine Production	Terminal Growth				
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	33.4	5.7	33.5	0.0
	Maximum Change in Traffic	10	2018	High	Med	22.6	0.0	22.5	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	33.4	0.0	33.5	0.0
	Maximum Change in Traffic	19	2018	High	Med	22.6	0.0	22.5	0.1

At Huntley, the BNSF Big Horn Subdivision main line from the Powder River Basin connects with the Forsyth Subdivision main line. West of Huntley to Mossmain (Figure 9-11) BNSF operates on Montana Rail Link (MRL) tracks.

Mossmain, Montana, to Sandpoint, Idaho

Table 9-41 summarizes projected train traffic for this segment, illustrated in Figure 9-14.

Figure 9-14. Mossmain, Montana to Sandpoint, Idaho via MRL (562.1 miles) or Shelby (657.5 miles)

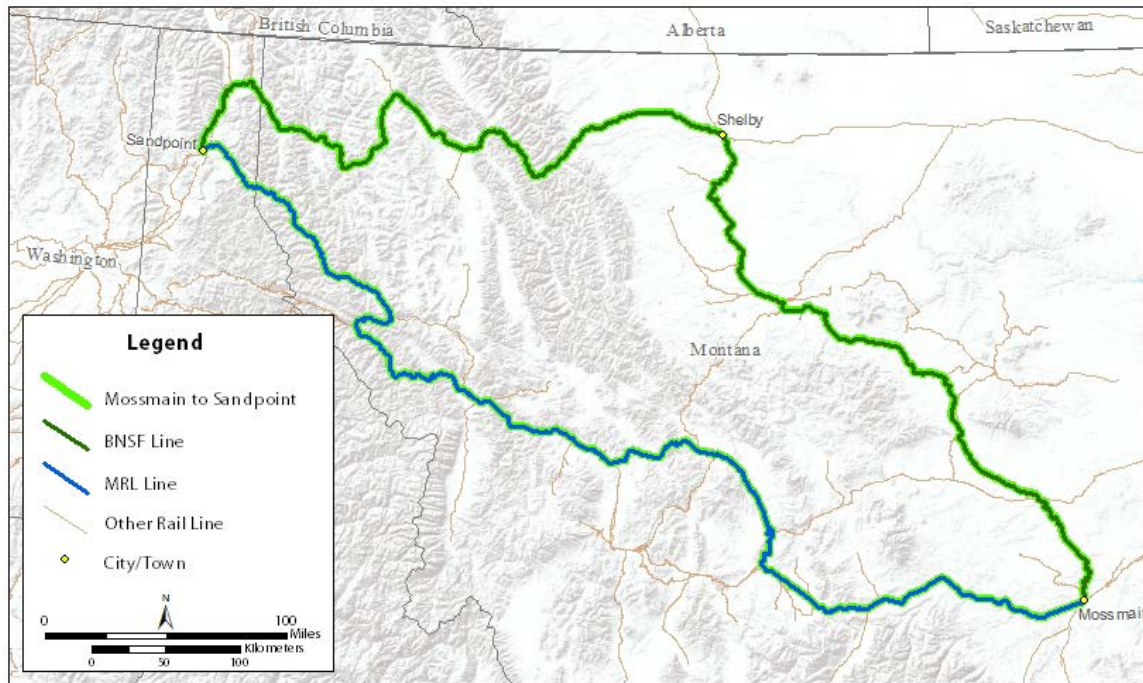


Table 9-41. Mossmain, Montana, to Sandpoint, Idaho

						Change in Traffic, Trains per Day			
Segment 35, 562.1 miles, Westbound						Total with			Change in
Main Tracks: 1				Mine	Terminal	Proposed	Proposed	No	Change in
Traffic Control System: CTC		Scenario	Year	Production	Growth	Action	Action	Action	Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	39.6	5.7	39.7	0.0
	Maximum Change in Traffic	10	2018	High	Med	28.1	0.0	28.0	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	39.7	0.0	39.7	0.0
	Maximum Change in Traffic	19	2018	High	Med	28.0	0.0	28.0	0.1

West of Mossmain there are two routes to Sandpoint, Idaho: via the MRL or on BNSF via the Shelby and BNSF Hi Line routes (Figure 9-12).

The MRL lines are owned by BNSF but have been operated by MRL (which is owned by Washington companies) since 1987. BNSF and MRL have a long-term lease purchase plan under which MRL will acquire the line. For this movement (and others), MRL serves as a bridge carrier for BNSF, which means BNSF hands the loaded trains to MRL at Mossmain and MRL hands the trains back to BNSF at Sandpoint. Bill of lading routing on trains moving over this route would show BNSF as the route.

The MRL route is 95.4 miles shorter than the Shelby/Hi Line route and is the primary route for the current BNSF export coal trains to Vancouver, British Columbia. This analysis provides detail about the MRL route. The Shelby/Hi Line is also an option for BNSF but the portion of the route from Shelby to Sandpoint is on BNSF's main east-west route from Chicago to the West Coast. This line has a high train volume of intermodal, grain and other traffic. It is likely BNSF would focus the coal traffic on the MRL.

Sandpoint, Idaho, to Spokane, Washington

Table 9-42 summarizes projected train traffic for this segment, illustrated in Figure 9-15.

Figure 9-15. Sandpoint, Idaho, to Spokane, Washington (66.6 miles)

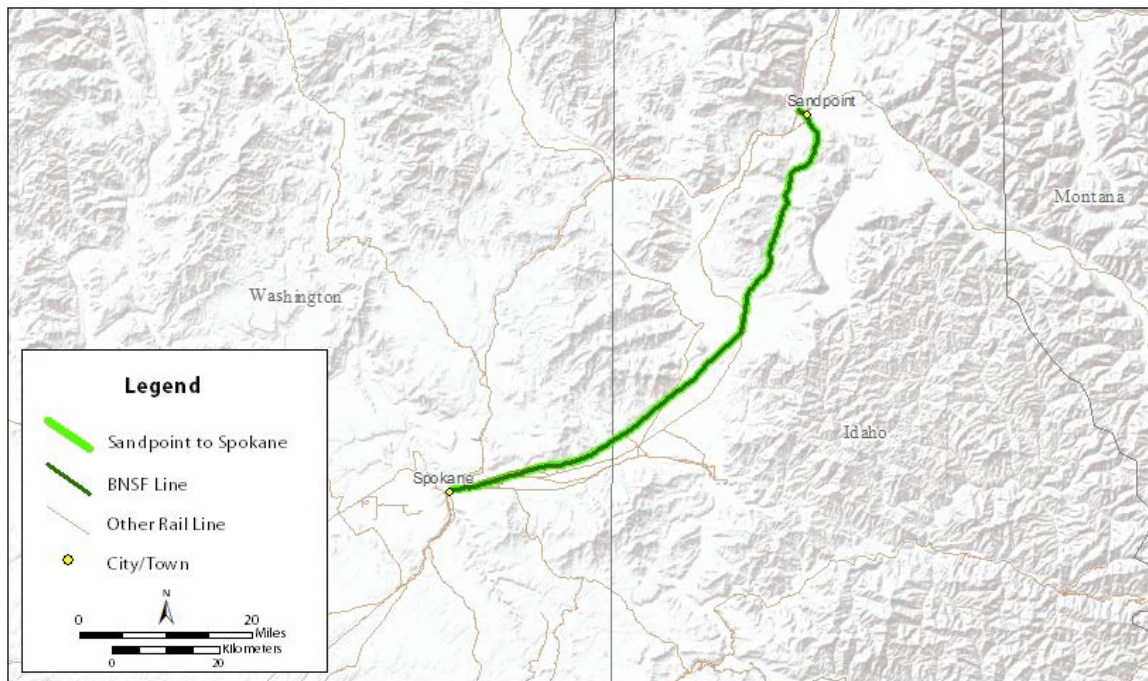


Table 9-42. Sandpoint, Idaho, to Spokane, Washington

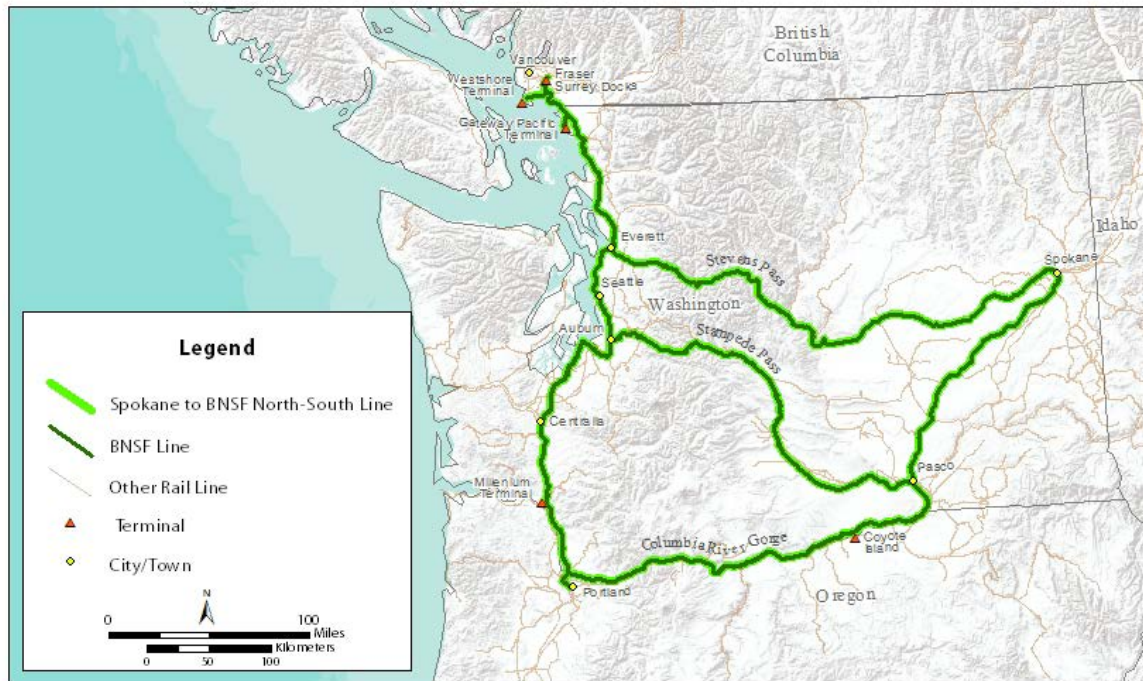
						Change in Traffic, Trains per Day			
Segment 38, 66.6 miles, Westbound Main Tracks: 2 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	69.3	5.7	69.3	0.0
	Maximum Change in Traffic	10	2018	High	Med	54.1	0.0	54.0	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	69.3	0.0	69.3	0.0
	Maximum Change in Traffic	19	2018	High	Med	54.0	0.0	54.0	0.1

All routes between Tongue River and the Pacific Northwest would move over the BNSF Kootenai River Subdivision between Sandpoint, Idaho, and Spokane, Washington (Figure 9-13). This section of BNSF is commonly known as “The Funnel.”

Spokane to Everett, Washington (Connection with BNSF North-South Line)

Table 9-43 summarizes projected train traffic for this segment, illustrated in Figure 9-14. There are three potential routes between Spokane and the BNSF north-south line, which connects Vancouver, British Columbia, with Portland, Oregon, via Seattle, Washington: Stevens Pass, Stampede Pass, and the Columbia River Gorge (Figure 9-16).

Figure 9-16. Spokane, Washington to BNSF North-South Line (Stevens Pass 291.7 miles; Stampede Pass 374.4 miles; Columbia River Gorge 243.6miles)



Spokane to Everett, Washington (Stevens Pass)

Table 9-43 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-43. Spokane to Everett, Washington

						Change in Traffic, Trains per Day			
Segment 39, 291.7 miles, Westbound						Total with			
Main Tracks: 1						Proposed	Proposed	No	Change
Traffic Control System: CTC						Action	Action	Action	in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	25.8	0.0	25.8	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	25.8	0.0	25.8	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	25.8	0.0	25.8	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	25.8	0.0	25.8	0.0

The Stevens Pass route is a key part of BNSF's transcontinental route for doublestack container trains and is on BNSF's finished auto network. Other traffic on the line includes agricultural, forest products, chemicals, and general merchandise. The line carries

westbound intermodal trains and eastbound grain and coal trains (empty backhaul direction). This line also carries the Amtrak Empire Builder passenger trains, one train each way per day.

This segment is discussed as a potential route for loaded and empty coal trains but all loaded and empty movements have been allocated to the Columbia River Gorge route for purposes of this analysis. Loaded coal trains move via this route today. The potential increase in volume is so great that BNSF may restructure its entire operation west of Spokane.

Spokane to Pasco, Washington

Table 9-44 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-44. Spokane to Pasco, Washington

						Change in Traffic, Trains per Day			
Segment 40, 145.5 miles, Westbound Main Tracks: 1 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	63.1	5.7	63.1	0.0
	Maximum Change in Traffic	10	2018	High	Med	48.6	0.0	48.5	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	63.1	0.0	63.1	0.0
	Maximum Change in Traffic	19	2018	High	Med	48.6	0.0	48.5	0.1

This segment from Spokane to Pasco, Washington (BNSF Lakeside Subdivision) is shared by both the Columbia River Gorge and Stampede Pass routes. Union Pacific Railroad (UP) has trackage rights over the easternmost 12 miles of the line. The Portland section of the Amtrak Empire Builder passenger train moves over this line.

Pasco to Auburn, Washington (Stampede Pass)

Table 9-45 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-45. Pasco to Auburn, Washington

						Change in Traffic, Trains per Day			
Segment 41, 374.4 miles, Westbound Main Tracks: 1 Traffic Control System: TWC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	3	2018	Low	Zero	5.4	0.0	5.4	0.0
	Maximum Change in Traffic	3	2018	Low	Zero	5.4	0.0	5.4	0.0
Southern Alternatives	Minimum Change in Traffic	12	2018	Low	Zero	5.4	0.0	5.4	0.0
	Maximum Change in Traffic	12	2018	Low	Zero	5.4	0.0	5.4	0.0

The portion of this route between Pasco and Auburn (BNSF Yakima Valley and Stampede Subdivisions) goes through the Stampede Tunnel. Doublestack trains cannot move over this route because of height restrictions at the tunnel. This is the least dense section of BNSF line between Spokane and Seattle.

Pasco to Wallula, Washington (Columbia River Gorge Route)

Table 9-46 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-46. Pasco to Wallula, Washington

						Change in Traffic, Trains per Day			
Segment 42, 13.1 miles, Westbound Main Tracks: 1 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	83.1	5.7	83.1	0.0
	Maximum Change in Traffic	10	2018	High	Med	66.1	0.0	66.1	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	83.1	0.0	83.1	0.0
	Maximum Change in Traffic	19	2018	High	Med	66.1	0.0	66.1	0.1

Pasco to Wallula is a short segment of 13.1 miles that extends from the BNSF Columbia River Gorge route to a connection UP at Wallula. At Wallula, BNSF would interchange shipments destined to the proposed Morrow Pacific Terminal in Boardman.

Wallula, Washington, to Boardman, Oregon (Union Pacific)

Table 9-47 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-47. Wallula, Washington, to Boardman, Oregon

						Change in Traffic, Trains per Day			
Segment 44, 50.4 miles, Westbound						Total with			
Main Tracks: 1						Proposed	Proposed	No	Change
Traffic Control System: CTC						Action	Action	Action	in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	57.0	0.0	57.0	0.0
	Maximum Change in Traffic	5	2030	Low	High	51.0	0.0	51.0	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	57.0	0.0	57.0	0.0
	Maximum Change in Traffic	17	2023	Med	High	44.4	0.0	44.4	0.0

This segment is part of a heavily used UP line.

Pasco, Washington, to Portland, Oregon (Columbia River Gorge Route)

Table 9-48 summarizes projected train traffic for this segment, illustrated in Figure 9-16.

Table 9-48. Pasco, Washington, to Portland, Oregon

						Change in Traffic, Trains per Day			
Segment 43, 243.6 miles, Westbound						Total with			
Main Tracks: 1						Proposed	Proposed	No	Change
Traffic Control System: CTC						Action	Action	Action	in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	59.6	5.4	59.7	0.0
	Maximum Change in Traffic	10	2018	High	Med	46.2	0.0	46.1	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	59.6	0.0	59.7	0.0
	Maximum Change in Traffic	19	2018	High	Med	46.2	0.0	46.1	0.1

This segment covers the majority of the Columbia River Gorge Route. BNSF generally moves loaded grain and coal trains westbound and loaded intermodal trains eastbound via the Columbia River Gorge route, which has the least grade of the three route options. The portion of the line from Spokane to Pasco, Washington (BNSF Lakeside Subdivision) is shared with the Stampede Pass route, as described above. The balance of the route (BNSF Fallbridge Subdivision) runs along the north side of the Columbia River and joins the north-south line at Vancouver, Washington, just north of Portland, Oregon. All export coal trains would move over this segment of the Columbia River Gorge route from Pasco to Wallula.

9.5.2.4 BNSF North-South Line

All but one of the proposed U.S. coal export terminals is located on the BNSF north-south line (Figure 9-17). The Canadian terminals and proposed terminal at Cherry Point, Washington, are located at the north end of the line, and the proposed terminal at Longview, Washington, at the south end of the line. One proposed terminal (Morrow) is on the Columbia River Gorge route.

Figure 9-17. BNSF North-South Line



Portland, Oregon, to Longview, Washington

Table 9-49 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-49. Portland, Oregon, to Longview, Washington

						Change in Traffic, Trains per Day			
Segment 45, 45 miles, Westbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	65.2	5.4	65.2	0.0
	Maximum Change in Traffic	10	2018	High	Med	51.0	0.0	50.9	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	65.2	0.0	65.2	0.0
	Maximum Change in Traffic	19	2018	High	Med	51.0	0.0	50.9	0.1

UP has trackage rights over this portion of the line and it is the main route between Portland and Seattle for both UP and BNSF. Longview is the location of the proposed Millennium Bulk Terminals.

Longview to Centralia, Washington

Table 9-50 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-50. Longview to Centralia, Washington

						Change in Traffic, Trains per Day			
Segment 46, 48.6 miles, Westbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	10	2023	High	Med	57.9	3.6	57.9	0.0
	Maximum Change in Traffic	10	2018	High	Med	47.7	0.0	47.6	0.1
Southern Alternatives	Minimum Change in Traffic	16	2023	Med	Med	57.9	0.0	57.9	0.0
	Maximum Change in Traffic	19	2018	High	Med	47.7	0.0	47.6	0.1

Centralia to Auburn, Washington

Table 9-51 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-51. Centralia to Auburn, Washington

						Change in Traffic, Trains per Day			
Segment 47, 72.6 miles, Westbound Main Tracks: 2 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	82.6	0.0	82.6	0.0
	Maximum Change in Traffic	5	2030	Low	High	76.0	0.0	76.0	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	82.6	0.0	82.6	0.0
	Maximum Change in Traffic	17	2023	Med	High	68.8	0.0	68.8	0.0

At Auburn, the Stampede Pass line connects with the BNSF north-south line.

Auburn to Everett, Washington

Table 9-52 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-52. Auburn to Everett, Washington: Projected Train Traffic for Year 2030

						Change in Traffic, Trains per Day			
Segment 48, 56.1 miles, Westbound Main Tracks: 1 Traffic Control System: CTC						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Scenario	Year	Mine Production	Terminal Growth						
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	68.1	0.0	68.1	0.0
	Maximum Change in Traffic	5	2030	Low	High	63.2	0.0	63.2	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	68.1	0.0	68.1	0.0
	Maximum Change in Traffic	17	2023	Med	High	57.8	0.0	57.8	0.0

At Everett, the Stevens Pass route connects with the BNSF north-south line.

Everett to Intalco, Washington

Table 9-53 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-53. Everett to Intalco, Washington

						Change in Traffic, Trains per Day			
Segment 49, 79.1 miles, Westbound Main Tracks: 1 Traffic Control System: CTC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	33.0	0.0	33.0	0.0
	Maximum Change in Traffic	5	2030	Low	High	32.0	0.0	32.0	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	33.0	0.0	33.0	0.0
	Maximum Change in Traffic	17	2023	Med	High	30.9	0.0	30.9	0.0

Intalco to Cherry Point, Washington

Table 9-54 summarizes projected train traffic for this segment, illustrated in Figure 9-17.

Table 9-54. Intalco to Cherry Point, Washington

						Change in Traffic, Trains per Day			
Segment 50, 8.9 miles, Westbound Main Tracks: 1 Traffic Control System: TWC		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	22.8	0.0	22.8	0.0
	Maximum Change in Traffic	5	2030	Low	High	22.4	0.0	22.4	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	22.8	0.0	22.8	0.0
	Maximum Change in Traffic	17	2023	Med	High	22.0	0.0	22.0	0.0

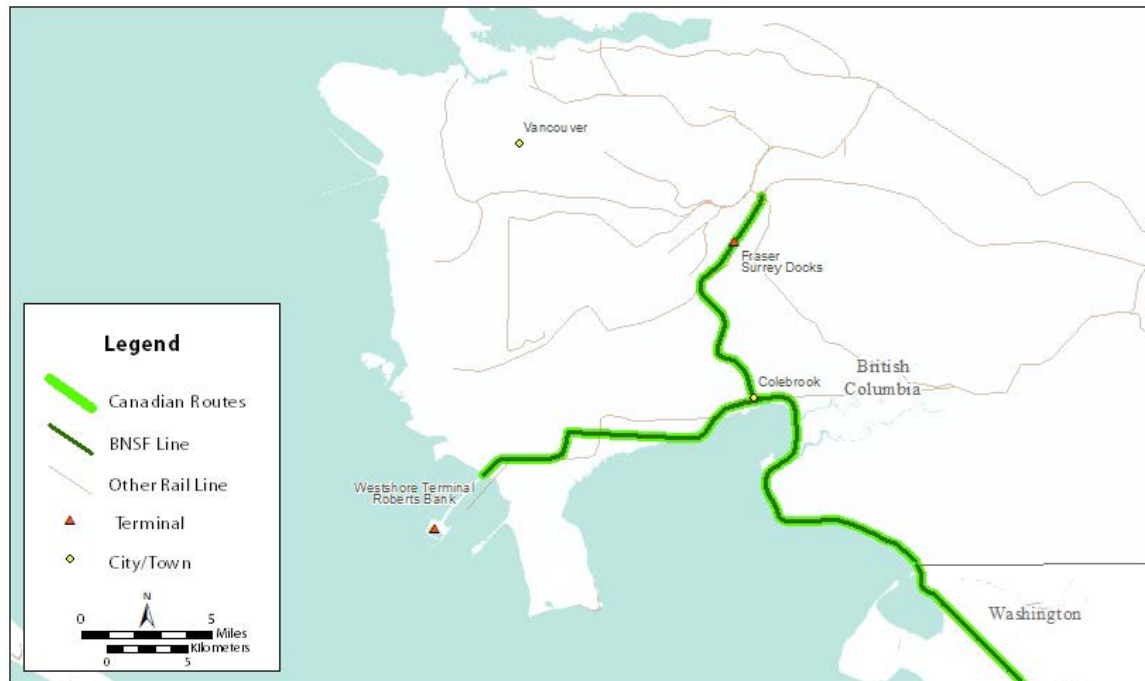
Only trains destined to the proposed Gateway Pacific Terminal at Cherry Point will use this segment.

9.5.2.5 Canadian Routes

At the United States/Canadian border, the route is over the BNSF New Westminster Subdivision via Colebrook to terminals at Fraser Surrey Docks or Roberts Bank

(Figure 9-18). All BNSF interchange traffic from Canadian National Railroad (CN) and Canadian Pacific Railway (CP) at New Westminster moves over this line.

Figure 9-18. Canadian Routes



Intalco, Washington, to Colebrook, British Columbia

Table 9-55 summarizes projected train traffic for this segment, illustrated in Figure 9-18.

Table 9-55. Intalco, Washington, to Colebrook, British Columbia

						Change in Traffic, Trains per Day			
Segment 51, 18.1 miles, Westbound						Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Main Tracks: 1									
Traffic Control System: CTC									
	Scenario	Year	Mine Production	Terminal Growth					
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	31.0	0.0	31.0	0.0
	Maximum Change in Traffic	5	2030	Low	High	28.0	0.0	28.0	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	31.0	0.0	31.0	0.0
	Maximum Change in Traffic	17	2023	Med	High	24.7	0.0	24.7	0.0

All trains to Westshore Terminals and Fraser Surrey Docks would move over this segment.
This section of the north-south line crosses the Canadian border.

Colebrook to Fraser Surrey Impex, British Columbia (Fraser Surrey Docks Terminal)

Table 9-56 summarizes projected train traffic for this segment, illustrated in Figure 9-18.

Table 9-56. Colebrook to Fraser Surrey Impex, British Columbia

Segment 52, 11.4 miles, Westbound Main Tracks: 1 Traffic Control System: CTC/ABS		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	22.9	0.0	22.9	0.0
	Maximum Change in Traffic	5	2030	Low	High	20.5	0.0	20.5	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	22.9	0.0	22.9	0.0
	Maximum Change in Traffic	17	2023	Med	High	17.9	0.0	17.9	0.0

All BNSF shipments to Fraser Surrey Docks would move north from Colebrook over this segment.

Colebrook to Roberts Bank, British Columbia (Westshore Terminals)

Table 9-57 summarizes projected train traffic for this segment, illustrated in Figure 9-18.

Table 9-57. Colebrook to Roberts Bank, British Columbia

Segment 53, 15.5 miles, Westbound Main Tracks: 1 Traffic Control System: CTC		Change in Traffic, Trains per Day							
		Scenario	Year	Mine Production	Terminal Growth	Total with Proposed Action	Proposed Action	No Action	Change in Traffic
Northern Alternatives	Minimum Change in Traffic	5	2037	Low	High	35.1	0.0	35.1	0.0
	Maximum Change in Traffic	5	2030	Low	High	31.5	0.0	31.5	0.0
Southern Alternatives	Minimum Change in Traffic	17	2037	Med	High	35.1	0.0	35.1	0.0
	Maximum Change in Traffic	17	2023	Med	High	27.5	0.0	27.5	0.0

Shipments to Westshore Terminals would move west from Colebrook over this segment to Roberts Bank, about 15 miles.

9.5.2.6 Export Coal Terminals

This section discusses existing and proposed terminals for the export of coal from the Powder River Basin to destinations in the Pacific Rim. Currently, approximately 8 million tons of Powder River Basin coal passes through the existing Westshore Terminal at Roberts Bank, British Columbia every year. Four coal export terminals are proposed in the Pacific Northwest and Vancouver: Gateway, Millennium, Morrow, and Fraser Surrey, (Chapter 4, *Proposed Coal Export Terminal Expansions*, provides additional information on the proposed export terminals). If all of these terminals are built, then exports of Powder River Basin coal could increase by some 114 million tons of coal per year. This additional capacity would be allocated as follows.

- SSA Marine Gateway Pacific Terminal: 52.8 million tons (46%).
- Millennium Bulk Terminal: 48.4 million tons (42%).
- Morrow Pacific Terminal: 8.8 million tons (8%).
- Fraser Surrey Docks: 4 million tons (4%).

SSA Marine Gateway Pacific Terminal at Cherry Point, Washington

The Gateway Pacific Terminal at Cherry Point would be located at the end of an 8.9-mile branch line (BNSF Cherry Point Subdivision), which splits from the BNSF north-south route at Intalco, Washington, just north of Custer (Figure 9-19). The line was built in 1965 to serve the Intalco aluminum smelter and some petroleum-related customers.

The Gateway Pacific Terminal has a proposed capacity of 52.8 million tons per year.⁶

⁶ Tongue River Railroad Company's Reply comments in Support of its Supplemental Application for Construction and Operating Authority, June 7, 2013.

Figure 9-19. SSA Marine Gateway Pacific Terminal at Cherry Point, Washington



Millennium Bulk Terminal at Longview, Washington

The Millennium Bulk Terminal currently operates on the Columbia River. The terminal is located on the BNSF north-south line at Longview, Washington, 45 miles north of Portland. Tongue River coal trains moving via the Columbia River Gorge route would move a relatively short distance on the BNSF north-south line to Longview. Empty trains could return either via the Columbia River Gorge route or via Stampede Pass without having to move through Seattle.

The planned coal export terminal has a proposed capacity of up to 48.4 million tons per year.

Morrow Pacific Terminal at Boardman, Oregon

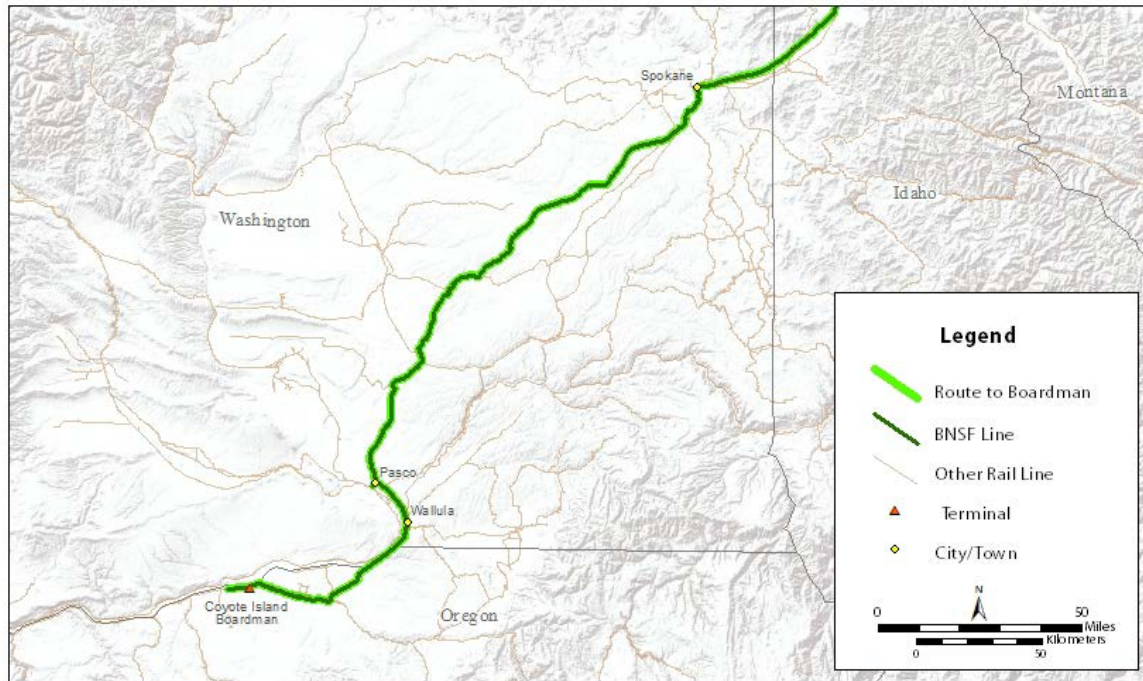
The Morrow Pacific Terminal currently being developed by Ambre Energy North America in Boardman, Oregon, is located on the UP route (Figure 9-20), discussed above under *Spokane to Auburn, Washington, via Stampede Pass*. BNSF could interchange with UP at Sandpoint, Idaho, or at Wallula, Washington, about 50.4 miles east of Boardman and 13.1 miles west of Pasco on the Columbia River Gorge route.

This is the only currently planned export terminal that is not on the north-south line. The planned export capacity is 8.8 million tons.⁷ Coal would be transloaded from railcars to

⁷ Morrow Pacific Project Packet P-2.

barges at Morrow and moved to the Port Westward Industrial Park at the Port of St. Helens for transload to ocean-going vessels.⁸

Figure 9-20. Morrow Pacific Terminal (Coyote Island) at Boardman, Oregon



Fraser Surrey Docks at Surrey, British Columbia

The coal-handling facility planned for Fraser Surrey Docks could transload up to 4 million tons of coal per year. Coal would be transloaded from railcars to barges for movement to Texada Island where it would be loaded onto ocean-going vessels (Port Metro Vancouver 2013).

Westshore Terminal at Roberts Bank, British Columbia

The Westshore Terminal is served by CN, CP, and BNSF, and handles both Canadian and U.S. export coal. It has a capacity of about 36 million tons per year, including the 8 million tons of Powder River Basin coal already shipped through this terminal. BNSF can access the terminal through joint track operation. No change in the current volume to Westshore is projected.

⁸ Ibid P-2.

Other Export Destinations No Longer Considered For Shipping

Ridley Terminal at Prince Rupert, British Columbia

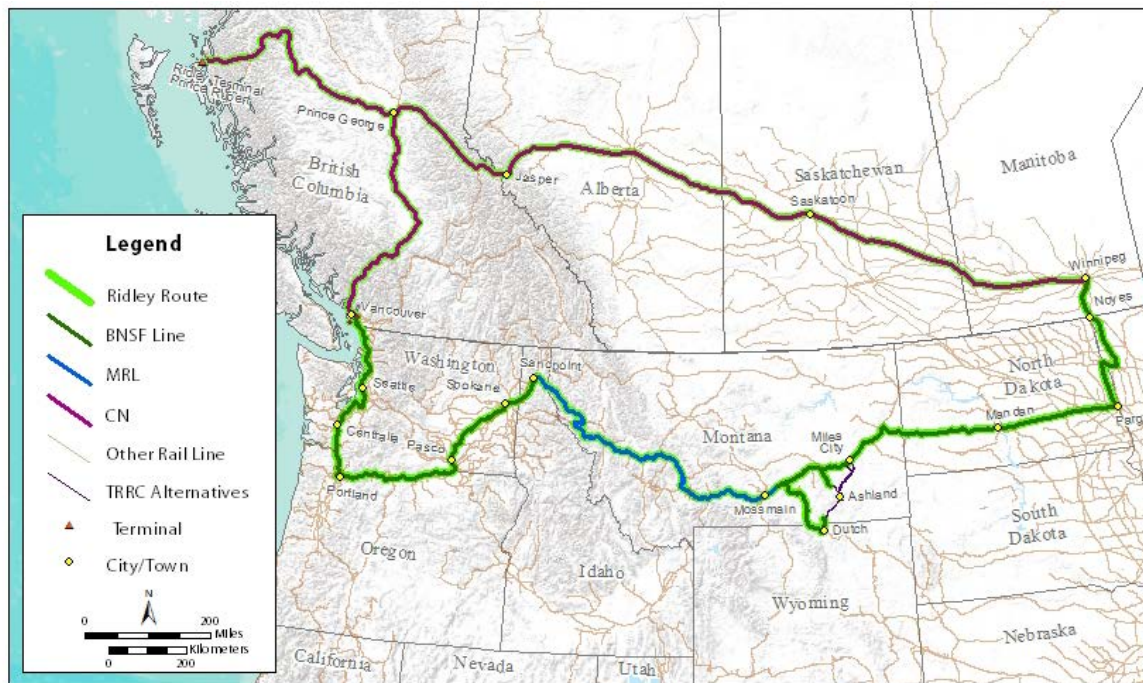
Tongue River coal could also move via the Ridley Terminal in Prince Rupert, British Columbia (Figure 9-21). In 2012, 2.2 million tons of Powder River Basin coal was exported via Ridley. Coal trains from the Powder River Basin to Ridley have moved over several different routes. The shortest haul, involving only two railroads (BNSF and CN), from Otter Creek is BNSF via Stevens Pass through New Westminster and Prince George to Ridley (2,320 miles). However, BNSF generally moves loaded trains via the Columbia River Gorge (2,434 miles) through Portland, Oregon, and empty trains via Stevens Pass. The Columbia River Gorge route is longer but flatter.

The CN portion of either of these routes involves moving trains on the former BC rail line from Vancouver to Prince George, British Columbia. This route has steep grades north of Lillooet to Prince George. CN currently routes mostly local traffic via this route. Through trains are routed from New Westminster via Kamloops (2,596 miles). It is likely that Tongue River coal trains would move through Kamloops. By comparison, the route from Tongue River to coal export terminals in Vancouver is 1,513 miles, considerably shorter than either route to Ridley regardless of how it is routed on CN.

In 2010, when prices in Asia peaked and there was no capacity available at Westshore, Arch Coal and Cloud Peak entered into contracts for export via Ridley. Because of the take-or-pay provisions, some shipments continued even after netbacks were no longer positive to minimize the negative impact.⁹ Asian prices are forecast to be low enough that future movements of Powder River Basin coal via Ridley would not be economically viable. Arch Coal was likely shipping 8800 Btu/lb Black Thunder coal. Cloud Peak was shipping Spring Creek and likely Signal Peak coal through Ridley.

⁹ A *take-or-pay* provision is one that can be included in a contract whereby one party is required to either take the delivery of goods or pay a specified amount.

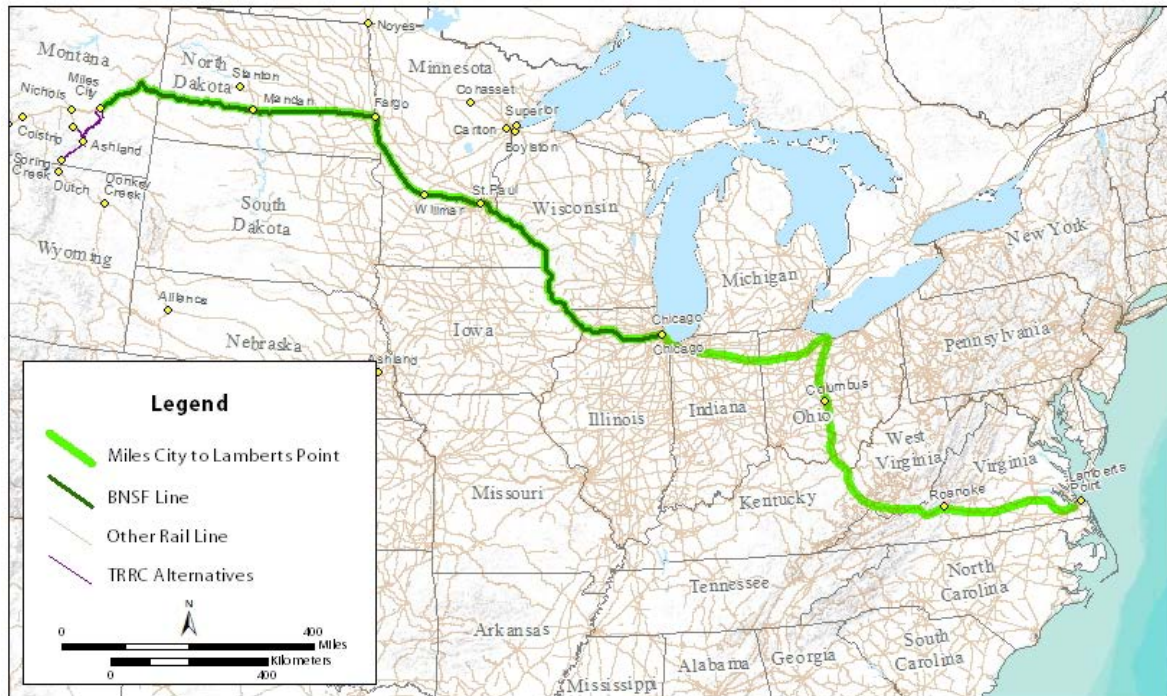
Figure 9-21. Ridley Terminal at Prince Rupert, British Columbia



Lamberts Point Terminal at Norfolk, Virginia

A small volume of Wyoming Powder River Basin coal is transported east for use at power plants that have specialized needs (Figure 9-22). This route is not considered an export option for Tongue River coal. This route is 2,341 miles on BNSF lines via Chicago to Lamberts Point Terminal at Norfolk, Virginia. An alternative route via the CSX rail line to Pier IX or the Dominion Terminal Associates terminal in Newport News, Virginia, would be similarly long. The costs per ton-mile on the eastern carriers would be higher than on the western carriers, and this would constitute more than half of the route. Tongue River coal would be more economically competitive if exported via the proposed western terminals.

Figure 9-22. Lamberts Point Terminal at Norfolk, Virginia



New Orleans and Texas Gulf Coast Ports

Tongue River coal could be shipped out of the Gulf Coast via New Orleans or Texas Gulf Coast ports. Coal could be shipped either directly by rail or by rail via St. Louis area and then by barge. These movements for Wyoming Powder River Basin coal occur both domestically and for Powder River Basin coal shipments to Europe.

Both BNSF and UP can access Gulf Coast ports via rail direct or a combination of rail and barge. For all rail movements to Houston, Otter Creek coal transported via the southern alternatives and BNSF would be 210 miles farther than coal originating in the Wyoming Powder River Basin. The Tongue River and BNSF route to Houston would also be 115 miles farther than the UP route for Wyoming Powder River Basin coal. For rail and barge movements, Otter Creek coal would be 143 miles farther to St. Louis than Wyoming Powder River Basin coal via BNSF, and 254 miles farther from St. Louis than Wyoming Powder River Basin coal transported via UP. UP also has access to higher Btu Colorado and Utah coal. Wyoming Powder River Basin, Colorado and Utah coal would be more favorably positioned than Tongue River coal for these movements. The Wyoming coals are located closer to the Gulf Coast ports, have lower freight-on-board mine prices, and lower rail rates than the Montana coals. While Spring Creek coal might compete in the Gulf, it is likely to obtain higher netbacks if sold into Asian markets via the Pacific Northwest. If it were to be sold into European or South American markets, it could move through Gulf ports.

9.6 Origin-Area Pricing

The competitiveness of Tongue River coal relative to other Powder River Basin coal is partly determined by relative rail rates. These rates are not based solely on distance, but on the mine location, loading capabilities, and how they are served. Rates are not calculated on the distance of specific mines to a destination, but on clusters of mines from *origin areas*. BNSF has followed this pattern for Powder River Basin mines. Gillette origin-area mines include all of the Wyoming mines. Sheridan origin-area mines include East Decker, West Decker, and Spring Creek Mines. Forsyth origin-area mines include Absaloka and Rosebud Mines. Tongue River mines in Montana would likely be in the Forsyth origin area for the northern route option (but potentially in the Sheridan origin area for the southern alternatives). The rate differentials for southbound movements would have the Sheridan origin-area mines at \$1.70 per ton more than the Gillette origin-area mines, and the Forsyth origin-area mines at a \$3.70 per ton more than the Gillette origin-area mines. This creates a strong incentive for these Montana coals to move to destinations over routes where they do not suffer these rate and distance differentials. Advantageous routes for Tongue River coal include the Pacific Northwest export routes, the Great Lakes via Superior terminal, and the northern tier utility plants. As a result, Tongue River coals could likely obtain higher netbacks to these destinations than to other markets where they would incur higher rates than the Wyoming Powder River Basin coals. Over the southern route, the rates for Tongue River coal would be \$2 per ton less going to southern U.S. destinations than if they were shipped via the northern route. Nonetheless, they would still be at a rate disadvantage relative to the Wyoming Powder River Basin coals to these markets, and at a Btu disadvantage relative to the Powder River Basin 8800 coals and the Spring Creek coal.

9.7 Summary of Scenarios and Conclusions

The analyses presented in this chapter result in the following conclusions regarding the impacts of the proposed rail line on coal production and transportation.

- Tongue River coal could move eastward to various domestic markets largely over existing infrastructure, once they have exited the Powder River Basin region.
- Tongue River coal could move westward to the export markets.
- The traffic volumes would vary depending on the market demand scenario, which, in turn, is partly a function of the development of the new coal export terminals.

While numerous scenarios have been run, there are some general patterns, which have emerged regarding how traffic flows shift under varying conditions. The following summaries are grouped according to these general patterns on traffic flow shifts.

- **Scenarios 3 through 6.** These scenarios assume a northern alternative is licensed and built with low to medium coal production rates with zero, medium, and high terminal

growth. Under these scenarios, OEA's results suggest that Tongue River coal would displace Wyoming or Montana Powder River Basin coal in markets in the western Great Lakes region. These scenarios would result in 7 to 11 trains per day on the proposed Tongue River Railroad between Ashland and Colstrip, Montana, and an increase in the number of trains on the BNSF system between Colstrip and Nichols, Montana. From Nichols, Montana to Willmar, Minnesota these scenarios would result in a net increase of 1 to 8 trains per day. A net reduction of 1 to 8 trains per day would occur between Belle Ayr, Wyoming/Thunder Junction Wyoming, and Willmar, Minnesota through Alliance, Nebraska, and Ashland, Nebraska.

- **Scenarios 7 through 11.** These scenarios also assume that a northern alternative is licensed and built with medium to high coal production rates with zero, medium, and high terminal growth. Under these scenarios, OEA's results suggest that Tongue River coal would displace Wyoming or Montana Powder River Basin coal in markets in the western Great Lakes region. These scenarios also show Tongue River coal would displace exports of Powder River Basin coal in small amounts. Scenario 10 includes additional incremental tonnage to the western Great Lakes and the Pacific Basin. Under Scenarios 7 through 11, net rail traffic would increase by 12 to 19 trains per day (operating first on the Tongue River Railroad from Ashland to Colstrip, Montana, and then on the BNSF from Colstrip to Nichols, Montana). On the BNSF line from Nichols, Montana to Willmar, Minnesota, these scenarios would result in a net increase of 8 to 15 trains per day. Scenarios 9 and 10 would also add a net of 6 to 8 trains per day trains from Willmar to St. Paul, Minnesota, and to Chicago, Illinois. Scenarios 7 through 11 would result in a net decrease of 1 to 14 trains per day between Belle Ayr Thunder Junction, Wyoming, and Willmar, Minnesota through Alliance and Ashland, Nebraska. These scenarios would add less than one train per day westbound to the Pacific Northwest terminals because the Tongue River coal would mostly displace current Powder River Basin coal moving over the same routes.
- **Scenarios 12 through 17.** These scenarios assume that a southern alternative would be built with low to medium coal production rates with zero, medium, and high terminal growth. Under these scenarios, Tongue River coal would displace Wyoming or Montana Powder River Basin coal mostly to the western Great Lakes, with some small displacement to the eastern Great Lakes and Upper Midwest. Scenarios 12 and 15 would add 6 and 13 trains per day, respectively, if the Tongue River Railroad is licensed and built, but they show little net impact on any part of the BNSF system. Under scenarios 13, 14, and 16 there would be 6 to 11 trains per day on the Tongue River Railroad between Ashland and Spring Creek, Montana. Between Spring Creek, Montana and Willmar, Minnesota through Huntley and Miles City, Montana, these scenarios would result in a net increase of 4 to 10 trains per day. A net reduction of 1 to 9 trains per day would occur between Belle Ayr/Thunder Junction, Wyoming, and Willmar, Minnesota through Alliance and Ashland, Nebraska.

- **Scenarios 18 through 20.** These scenarios assume that a southern alternative would be built with medium to high coal production rates with zero, medium, and high terminal growth. These scenarios would affect essentially the same segments of the BNSF system as scenarios 12 through 17 but the volumes of additional traffic would be larger. Scenarios 18 through 20 would add a net of 25 to 27 trains per day between Ashland and Spring Creek, Montana. Between Spring Creek, Montana and Dutch, Wyoming there would be a net increase of 15 to 25 trains per day. Between Dutch, Wyoming, through Miles City, Montana to Willmar, Minnesota, these scenarios would result in a net increase of 1 to 9 trains per day. There would be net decreases of 3 to 11 trains per day between Belle Ayr and Donkey Creek, Wyoming, 10 to 14 trains per day between Thunder Junction, Wyoming, and Alliance, Nebraska, and 0 to 9 trains per day between Alliance, Nebraska and Willmar, Minnesota. Scenario 20 would also result in net reductions of 8 to 13 trains per day between Dutch, Wyoming, and Alliance, Nebraska.
- **Scenarios 21 through 23.** These scenarios assume that a northern alternative would be built and are sensitivity analyses for natural gas and CO₂, as explained in Chapter 7, *Scenarios*. These scenarios would result in 7.4 trains per day on the Tongue River Railroad between Ashland and Colstrip, Montana, and on the BNSF line from Colstrip to Nichols, Montana. On the BNSF, these scenarios would result in a net increase of 1 to 8 trains per day between Nichols, Montana and Willmar, Minnesota. Net decreases of 0 to 8 trains per day would occur between Spring Creek, Montana and Willmar, Minnesota through Alliance and Ashland, Nebraska.

10.1 Introduction

This chapter discusses the changes in air emissions that are likely to occur from the combustion of Tongue River coal. The emissions impacts examined here include carbon dioxide (CO₂), sulfur dioxide (SO₂), and mercury.

10.2 Emissions Assumptions

Using modeling, OEA estimated emissions of CO₂, SO₂, and mercury for domestic power plants. To estimate SO₂ and mercury emissions in the Pacific Basin, OEA made assumptions regarding the emissions reduction rates for SO₂ and mercury for the 2018 to 2037 analysis period.¹ Up-to-date and reliable information on control equipment and emissions rates are lacking for many coal plants in the Pacific Basin. Thus, OEA took a conservative approach in estimating the emissions reduction rates that may somewhat overestimate the emissions of SO₂ and mercury. Using historical coal consumption data and estimates of emissions reduction rates for each of 12 Pacific Basin countries, OEA calculated a weighted average emissions reduction rate.² The approach is conservative because OEA assumed that the current estimated emissions reduction rates do not increase over time. Most likely, additional controls will be installed in the future; however, the timing and amount is highly uncertain.

OEA assumed that, from 2018 to 2037, 57% of SO₂ and 50% of mercury would be captured by environmental controls on coal plants, as estimated from projected controls on power plants in the 12 Pacific Basin countries. As China consumes about 75% of the coal in the Pacific Basin, the environmental controls on Chinese power plants have a significant influence on the overall average emissions reduction factor (United Nations Environment Programme 2011). Based on an inventory of existing and planned environmental controls, OEA assumed that U.S. emissions reduction factors for coal plants, from 2018 to 2037, would average 75% for SO₂ emissions and 90% for mercury emissions.

¹ The emissions reduction rate is the percent of a pollutant that is removed by using active or passive controls on power plant emissions. The emissions rate for a pollutant is one minus the emissions reduction rate.

² The 12 Pacific Basin countries are Australia, China, Hong Kong, India, Indonesia, Japan, South Korea, Malaysia, Pakistan, Taiwan, Thailand, and Vietnam. OEA included Hong Kong separately from China since EIA data report it separately. OEA obtained the historical coal consumption data from EIA.

10.3 Carbon Dioxide Emissions

This section presents the CO₂ emissions for the No-Action Alternative and action scenarios. OEA presents the CO₂ results in million metric tons³ for the United States and Pacific Basin to account for changes in global CO₂ emissions from the development of the Tongue River Railroad.

10.3.1 Carbon Dioxide Emissions under the No-Action Alternative

The scope of this analysis included emissions from coal and natural gas consumption by electric generators in the United States and emissions from coal produced in the United States and globally, with a focus on the Pacific Basin. These two methods were used to show the CO₂ emissions due to changes in coal and natural gas consumption in the United States and those due to coal mined in the United States but consumed either in the United States or exported and consumed internationally. Under the No-Action Alternative scenarios, OEA estimated the CO₂ emissions from these sources for the period 2018 to 2037 for both the United States and the Pacific Basin. OEA included CO₂ emissions from the consumption of coal in the Pacific Basin in this analysis because a portion of Tongue River coal may be exported to this region, and the Tongue River Railroad may cause a shift in the type of coal exported to the Pacific Basin. Table 10-1 presents the annual U.S. CO₂ emissions from coal and gas-fired electrical generators for the six scenarios under the No-Action Alternative; Table 10-2 presents CO₂ emissions from coal for the Pacific Basin. OEA calculated the averages from 2018 to 2037. Tables 10-3, 10-4, and 10-5 present the No-Action CO₂ emissions from combusted coal that was mined in the Tongue River, other Powder River Basin areas, and in other U.S. coal basins.

³ OEA reports the values for CO₂ emissions in metric tons rather than short tons for a consistent comparison with other analyses such as the CAFÉ EIS.

Table 10-1. U.S. Carbon Dioxide Emissions from Coal and Natural Gas-Fired Generators (million metric tons per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	2,147	2,299	2,411	2,674	2,383
25	No-Action Alternative	Medium	No TRR, Med	2,144	2,297	2,408	2,672	2,380
2	No-Action Alternative	High	No TRR, High	2,135	2,294	2,405	2,670	2,376
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	2,025	2,226	2,412	2,692	2,339
27	No-Action Alternative	High	No TRR, High, Low Gas	2,020	2,217	2,407	2,689	2,333
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	2,116	2,210	2,249	2,320	2,224
Average								2,339

Table 10-2. Pacific Basin Carbon Dioxide Emissions from Coal (million metric tons per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	13,009	14,047	15,207	16,540	14,701
25	No-Action Alternative	Medium	No TRR, Med	13,010	14,050	15,210	16,543	14,703
2	No-Action Alternative	High	No TRR, High	13,012	14,054	15,213	16,547	14,707
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	13,009	14,047	15,207	16,540	14,701
27	No-Action Alternative	High	No TRR, High, Low Gas	13,012	14,054	15,213	16,547	14,707
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	13,012	14,054	15,213	16,547	14,707
Average								14,704

Table 10-3. U.S. Carbon Dioxide Emissions from Coal Produced in the Tongue River (million metric tons)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions over 2018 to 2037 MMT CO ₂
1	No-Action Alternative	Zero	No TRR, Zero	0	0
25	No-Action Alternative	Medium	No TRR, Med	0	0
2	No-Action Alternative	High	No TRR, High	0	0
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	0	0
27	No-Action Alternative	High	No TRR, High, Low Gas	0	0
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	0	0

Table 10-4. U.S. Carbon Dioxide Emissions from Coal Produced in the Other Powder River Basin Areas (million metric tons)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions over 2018 to 2037 MMT CO ₂
1	No-Action Alternative	Zero	No TRR, Zero	796	15,927
25	No-Action Alternative	Medium	No TRR, Med	869	17,372
2	No-Action Alternative	High	No TRR, High	935	18,705
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	762	15,232
27	No-Action Alternative	High	No TRR, High, Low Gas	911	18,219
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	870	17,402

Table 10-5. U.S. Carbon Dioxide Emissions from Coal Produced in Other U.S. Coal Basins (million metric tons)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	Annual Average CO2 Emissions MMT CO2/year	Total CO2 Emissions over 2018 to 2037 MMT CO2
1	No-Action Alternative	Zero	No TRR, Zero	1,007	20,147
25	No-Action Alternative	Medium	No TRR, Med	1,014	20,279
2	No-Action Alternative	High	No TRR, High	1,033	20,661
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	949	18,981
27	No-Action Alternative	High	No TRR, High, Low Gas	965	19,293
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	938	18,756

Figure 10-1. Annual U.S. Carbon Dioxide Emissions from Coal and Natural Gas by No-Action Alternative Scenarios, Averaged 2018 to 2037 (million metric tons per year) (scenarios 1, 25, 2, 26, 27, 24)

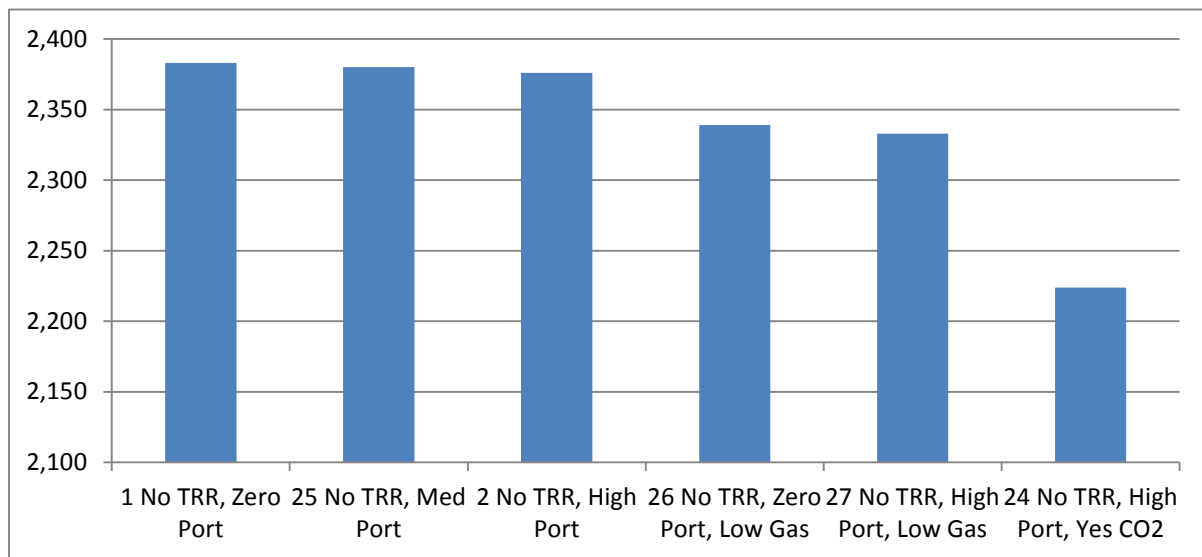
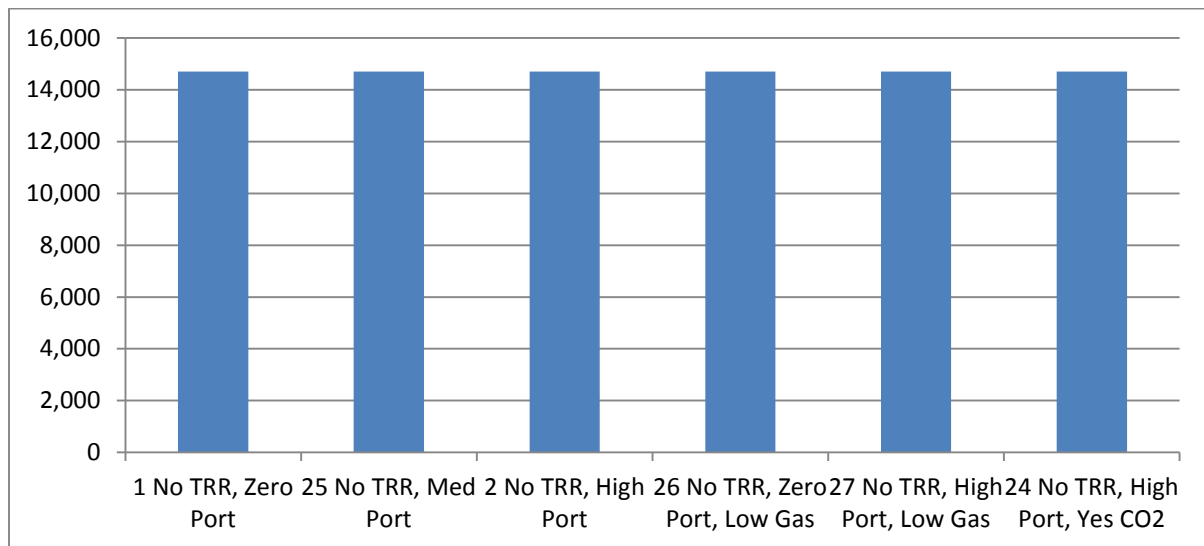


Figure 10-2. Annual Pacific Basin Carbon Dioxide Emissions from Coal by No-Action Alternative Scenarios, Averaged 2018 to 2037 (million metric tons per year) (scenarios 1, 25, 2, 26, 27, 24)



10.3.2 U.S. Carbon Dioxide Emissions from Coal and Natural Gas-Fired Generation

If the Tongue River Railroad were constructed, CO₂ emissions would increase because of the consumption of Tongue River coal. The total CO₂ emissions from Tongue River coal would be higher or lower depending on total coal consumption and natural gas consumption. OEA found that, on average, from 2018 to 2037 across all 21 primary sensitivity scenarios, 95% of Tongue River coal would displace other U.S. coal production. As a result, the overall U.S. increase in CO₂ emissions from Tongue River coal would be less than the emissions from the direct combustion of Tongue River coal. Similarly, changes in natural gas consumption would increase or decrease the total CO₂ emissions from Tongue River coal. Table 10-6 shows the U.S. CO₂ emissions from coal and natural gas-fired electric generators for each scenario. Table 10-7 contains the change in CO₂ emissions in the United States from the development of the Tongue River Railroad compared to the No-Action Alternative.

Table 10-6. U.S. Carbon Dioxide Emissions from Coal and Natural Gas (million metric tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	2,148	2,299	2,411	2,675	2,383
4	Northern	Low	Medium	N, Low, Med	2,145	2,297	2,409	2,672	2,381
5	Northern	Low	High	N, Low, High	2,139	2,295	2,407	2,671	2,378
6	Northern	Medium	Zero	N, Med, Zero	2,149	2,300	2,412	2,675	2,384
7	Northern	Medium	Medium	N, Med, Med	2,147	2,299	2,411	2,674	2,383
8	Northern	Medium	High	N, Med, High	2,140	2,297	2,408	2,673	2,379
9	Northern	High	Zero	N, High, Zero	2,149	2,300	2,412	2,675	2,384
10	Northern	High	Medium	N, High, Med	2,149	2,300	2,412	2,675	2,384
11	Northern	High	High	N, High, High	2,145	2,297	2,409	2,672	2,381
12	Southern	Low	Zero	S, Low, Zero	2,148	2,299	2,411	2,675	2,383
13	Southern	Low	Medium	S, Low, Med	2,145	2,297	2,409	2,672	2,381
14	Southern	Low	High	S, Low, High	2,139	2,295	2,407	2,671	2,378
15	Southern	Medium	Zero	S, Med, Zero	2,149	2,300	2,412	2,675	2,384
16	Southern	Medium	Medium	S, Med, Med	2,146	2,298	2,410	2,673	2,382
17	Southern	Medium	High	S, Med, High	2,140	2,296	2,407	2,672	2,379
18	Southern	High	Zero	S, High, Zero	2,149	2,300	2,413	2,676	2,385
19	Southern	High	Medium	S, High, Med	2,148	2,299	2,412	2,675	2,383
20	Southern	High	High	S, High, High	2,144	2,297	2,409	2,673	2,381
21	Northern	Low	Zero	N, Low, Zero, Low Gas	2,027	2,229	2,413	2,693	2,341
22	Northern	Low	High	N, Low, High, Low Gas	2,021	2,220	2,408	2,689	2,335
23	Northern	Low	High	N, Low, High, Yes CO ₂	2,118	2,210	2,251	2,321	2,225
Average									2,370

Table 10-7. Change in U.S. Carbon Dioxide Emissions from Coal and Natural Gas Relative to No-Action Alternative (million metric tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	1.1	0.4	0.2	0.1	0.5
4	Northern	Low	Medium	N, Low, Med	1.3	0.4	0.1	(0.1)	0.4
5	Northern	Low	High	N, Low, High	3.9	1.5	1.9	0.5	1.9
6	Northern	Medium	Zero	N, Med, Zero	1.5	1.6	0.9	0.7	1.2
7	Northern	Medium	Medium	N, Med, Med	2.6	2.2	2.8	1.2	2.2
8	Northern	Medium	High	N, Med, High	5.1	3.1	3.7	2.2	3.5
9	Northern	High	Zero	N, High, Zero	2.1	1.7	0.8	0.4	1.3
10	Northern	High	Medium	N, High, Med	4.4	3.1	3.1	2.5	3.3
11	Northern	High	High	N, High, High	9.8	3.5	4.6	2.0	5.0
12	Southern	Low	Zero	S, Low, Zero	1.0	0.4	0.2	0.1	0.4
13	Southern	Low	Medium	S, Low, Med	1.3	0.5	0.0	0.0	0.5
14	Southern	Low	High	S, Low, High	4.0	1.6	1.9	0.9	2.1
15	Southern	Medium	Zero	S, Med, Zero	1.3	0.9	0.4	0.3	0.7
16	Southern	Medium	Medium	S, Med, Med	1.8	0.9	1.6	1.0	1.3
17	Southern	Medium	High	S, Med, High	4.6	2.3	2.8	1.5	2.8
18	Southern	High	Zero	S, High, Zero	2.1	1.5	1.4	1.4	1.6
19	Southern	High	Medium	S, High, Med	4.1	2.5	3.0	2.2	3.0
20	Southern	High	High	S, High, High	9.2	3.1	4.4	2.5	4.8
21	Northern	Low	Zero	N, Low, Zero, Low Gas	2.3	2.3	1.4	0.9	1.7
22	Northern	Low	High	N, Low, High, Low Gas	1.6	3.0	0.8	0.4	1.4
23	Northern	Low	High	N, Low, High, Yes CO ₂	1.7	(0.1)	1.2	1.6	1.1
Average									1.9

Total annual production Tongue River coal ranges from 5 million tons per year (scenario 12) to 72 million tons per year (scenarios 19 and 20). Over all 21 primary sensitivity scenarios and from 2018 to 2037, the average annual production of Tongue River coal is 30.6 million tons per year with a range of 13.8 million tons year (scenario 12) to 57 million tons per year (scenarios 19 and 20). Because Tongue River coal would displace 95% of other U.S. coal production, the average incremental increase in coal production would be 1.4 million tons per year, averaged over all scenarios from 2018 to 2037. The range would be from zero (scenarios 3 and 12) to 3.8 million tons per year (scenario 11), corresponding to a total increase in coal consumption ranging from zero (scenarios 3 and 12) to 78.3 million tons (scenario 11) from 2018 to 2037. For each year, the change in U.S. coal production would range from a decrease of 2.7 million tons in 2030 (scenario 12) to an increase of 8.8 million tons in 2018 (scenario 11).

Across the 21 primary sensitivity scenarios, total U.S. coal CO₂ emissions from the incremental consumption of Tongue River coal averaged over 2018 to 2037 would range from an increase of 0.4 to 6.4 million metric tons per year and would average an increase of 2.4 million metric tons of CO₂ per year. Total U.S. coal and natural gas CO₂ emissions from the incremental consumption of Tongue River coal averaged over 2018 to 2037 would range from an increase of 0.4 to 5.0 million metric tons per year and would average an increase of 1.9 million metric tons of CO₂ per year. Decreased consumption of natural gas would partially offset some of the increase in CO₂ emissions from the consumption of Tongue River coal.

OEA also determined the total and annual average CO₂ emissions from the consumption of Tongue River Coal, the consumption of other, non-Tongue River, Powder River Basin coal, and the consumption of all other U.S. coal, regardless of where it was consumed. OEA performed these same calculations for all non-U.S. coal production. Finally, OEA calculated the differences from the No-Action scenarios for each of the 21 scenarios. Changes in global coal production were only observed in the Pacific Basin, due to the changes in the coal types exported out of the Pacific Northwest, and in Colombia, which is an exporter to the United States. All other coal production remained the same between the proposed and no-action scenarios. Thus, the difference in CO₂ emissions from coal mined in all but the United States, Pacific Basin, and Colombia was zero between the proposed action and no-action scenarios. Tables 10-8, 10-9, and 10-10 present the CO₂ emissions from coal produced from the Tongue River area, other Powder River Basin regions, and other U.S. mining regions; and Table 10-11 presents the CO₂ emissions from the combustion of the total amount of thermal coal produced in the United States. Tables 10-12, 10-13, and 10-14 present the annual average CO₂ emissions and the total CO₂ emissions over the 2018 to 2037 period for the same three regions.

Table 10-8. Carbon Dioxide Emissions from Tongue River Coal (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	33	664
4	Northern	Low	Medium	N, Low, Med	33	664
5	Northern	Low	High	N, Low, High	33	664
6	Northern	Medium	Zero	N, Med, Zero	48	967
7	Northern	Medium	Medium	N, Med, Med	48	968
8	Northern	Medium	High	N, Med, High	48	968
9	Northern	High	Zero	N, High, Zero	73	1,452
10	Northern	High	Medium	N, High, Med	77	1,534
11	Northern	High	High	N, High, High	77	1,534
12	Southern	Low	Zero	S, Low, Zero	23	469
13	Southern	Low	Medium	S, Low, Med	33	664
14	Southern	Low	High	S, Low, High	33	664
15	Southern	Medium	Zero	S, Med, Zero	43	855
16	Southern	Medium	Medium	S, Med, Med	47	944
17	Southern	Medium	High	S, Med, High	47	944
18	Southern	High	Zero	S, High, Zero	89	1,786
19	Southern	High	Medium	S, High, Med	96	1,920
20	Southern	High	High	S, High, High	96	1,920
21	Northern	Low	Zero	N, Low, Zero, Low Gas	33	664
22	Northern	Low	High	N, Low, High, Low Gas	33	664
23	Northern	Low	High	N, Low, High, Yes CO ₂	33	664

Table 10-9. Carbon Dioxide Emissions from Other Powder River Basin Coal (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	773	15,463
4	Northern	Low	Medium	N, Low, Med	839	16,783
5	Northern	Low	High	N, Low, High	917	18,330
6	Northern	Medium	Zero	N, Med, Zero	762	15,247
7	Northern	Medium	Medium	N, Med, Med	827	16,548
8	Northern	Medium	High	N, Med, High	904	18,081
9	Northern	High	Zero	N, High, Zero	740	14,803
10	Northern	High	Medium	N, High, Med	806	16,118
11	Northern	High	High	N, High, High	882	17,647
12	Southern	Low	Zero	S, Low, Zero	779	15,588
13	Southern	Low	Medium	S, Low, Med	840	16,797
14	Southern	Low	High	S, Low, High	917	18,337
15	Southern	Medium	Zero	S, Med, Zero	766	15,326
16	Southern	Medium	Medium	S, Med, Med	828	16,565
17	Southern	Medium	High	S, Med, High	905	18,093
18	Southern	High	Zero	S, High, Zero	724	14,476
19	Southern	High	Medium	S, High, Med	795	15,908
20	Southern	High	High	S, High, High	866	17,326
21	Northern	Low	Zero	N, Low, Zero, Low Gas	736	14,720
22	Northern	Low	High	N, Low, High, Low Gas	882	17,644
23	Northern	Low	High	N, Low, High, Yes CO ₂	842	16,849

Table 10-10. Carbon Dioxide Emissions from Other Non-Powder River Basin Coal (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	998	19,955
4	Northern	Low	Medium	N, Low, Med	1,011	20,213
5	Northern	Low	High	N, Low, High	1,021	20,425
6	Northern	Medium	Zero	N, Med, Zero	994	19,883
7	Northern	Medium	Medium	N, Med, Med	1,009	20,184
8	Northern	Medium	High	N, Med, High	1,020	20,407
9	Northern	High	Zero	N, High, Zero	992	19,845
10	Northern	High	Medium	N, High, Med	1,003	20,066
11	Northern	High	High	N, High, High	1,015	20,308
12	Southern	Low	Zero	S, Low, Zero	1,001	20,027
13	Southern	Low	Medium	S, Low, Med	1,010	20,202
14	Southern	Low	High	S, Low, High	1,021	20,424
15	Southern	Medium	Zero	S, Med, Zero	995	19,908
16	Southern	Medium	Medium	S, Med, Med	1,009	20,175
17	Southern	Medium	High	S, Med, High	1,020	20,405
18	Southern	High	Zero	S, High, Zero	992	19,846
19	Southern	High	Medium	S, High, Med	994	19,888
20	Southern	High	High	S, High, High	1,013	20,251
21	Northern	Low	Zero	N, Low, Zero, Low Gas	944	18,879
22	Northern	Low	High	N, Low, High, Low Gas	962	19,249
23	Northern	Low	High	N, Low, High, Yes CO ₂	933	18,660

Table 10-11. Carbon Dioxide Emissions from Total Coal Produced in the United States (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	1,804	36,082
4	Northern	Low	Medium	N, Low, Med	1,883	37,660
5	Northern	Low	High	N, Low, High	1,971	39,419
6	Northern	Medium	Zero	N, Med, Zero	1,805	36,098
7	Northern	Medium	Medium	N, Med, Med	1,885	37,700
8	Northern	Medium	High	N, Med, High	1,973	39,456
9	Northern	High	Zero	N, High, Zero	1,805	36,100
10	Northern	High	Medium	N, High, Med	1,886	37,718
11	Northern	High	High	N, High, High	1,974	39,489
12	Southern	Low	Zero	S, Low, Zero	1,804	36,084
13	Southern	Low	Medium	S, Low, Med	1,883	37,663
14	Southern	Low	High	S, Low, High	1,971	39,424
15	Southern	Medium	Zero	S, Med, Zero	1,804	36,090
16	Southern	Medium	Medium	S, Med, Med	1,884	37,684
17	Southern	Medium	High	S, Med, High	1,972	39,441
18	Southern	High	Zero	S, High, Zero	1,805	36,109
19	Southern	High	Medium	S, High, Med	1,886	37,717
20	Southern	High	High	S, High, High	1,975	39,498
21	Northern	Low	Zero	N, Low, Zero, Low Gas	1,713	34,263
22	Northern	Low	High	N, Low, High, Low Gas	1,878	37,557
23	Northern	Low	High	N, Low, High, Yes CO ₂	1,809	36,172

Table 10-12. Change in Carbon Dioxide Emissions from Tongue River Coal Relative to No-Action Alternative (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	33.19	663.8
4	Northern	Low	Medium	N, Low, Med	33.19	663.8
5	Northern	Low	High	N, Low, High	33.19	663.8
6	Northern	Medium	Zero	N, Med, Zero	48.36	967.1
7	Northern	Medium	Medium	N, Med, Med	48.40	968.0
8	Northern	Medium	High	N, Med, High	48.40	968.0
9	Northern	High	Zero	N, High, Zero	72.62	1,452.3
10	Northern	High	Medium	N, High, Med	76.71	1,534.1
11	Northern	High	High	N, High, High	76.71	1,534.1
12	Southern	Low	Zero	S, Low, Zero	23.44	468.9
13	Southern	Low	Medium	S, Low, Med	33.19	663.8
14	Southern	Low	High	S, Low, High	33.19	663.8
15	Southern	Medium	Zero	S, Med, Zero	42.77	855.5
16	Southern	Medium	Medium	S, Med, Med	47.21	944.2
17	Southern	Medium	High	S, Med, High	47.19	943.8
18	Southern	High	Zero	S, High, Zero	89.32	1,786.4
19	Southern	High	Medium	S, High, Med	96.02	1,920.4
20	Southern	High	High	S, High, High	96.02	1,920.4
21	Northern	Low	Zero	N, Low, Zero, Low Gas	33.19	663.8
22	Northern	Low	High	N, Low, High, Low Gas	33.19	663.8
23	Northern	Low	High	N, Low, High, Yes CO ₂	33.19	663.8

Table 10-13. Change in Carbon Dioxide Emissions from Other Powder River Basin Coal Relative to No-Action Alternative (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	-23.20	-464.0
4	Northern	Low	Medium	N, Low, Med	-29.44	-588.8
5	Northern	Low	High	N, Low, High	-18.75	-375.0
6	Northern	Medium	Zero	N, Med, Zero	-33.98	-679.7
7	Northern	Medium	Medium	N, Med, Med	-41.21	-824.2
8	Northern	Medium	High	N, Med, High	-31.19	-623.8
9	Northern	High	Zero	N, High, Zero	-56.20	-1,123.9
10	Northern	High	Medium	N, High, Med	-62.69	-1,253.8
11	Northern	High	High	N, High, High	-52.90	-1,058.0
12	Southern	Low	Zero	S, Low, Zero	-16.97	-339.4
13	Southern	Low	Medium	S, Low, Med	-28.73	-574.5
14	Southern	Low	High	S, Low, High	-18.42	-368.4
15	Southern	Medium	Zero	S, Med, Zero	-30.06	-601.3
16	Southern	Medium	Medium	S, Med, Med	-40.36	-807.2
17	Southern	Medium	High	S, Med, High	-30.61	-612.2
18	Southern	High	Zero	S, High, Zero	-72.56	-1,451.3
19	Southern	High	Medium	S, High, Med	-73.18	-1,463.7
20	Southern	High	High	S, High, High	-68.93	-1,378.6
21	Northern	Low	Zero	N, Low, Zero, Low Gas	-25.60	-512.1
22	Northern	Low	High	N, Low, High, Low Gas	-28.78	-575.6
23	Northern	Low	High	N, Low, High, Yes CO ₂	-27.69	-553.9

Table 10-14. Change in Carbon Dioxide Emissions from Other, non-Powder River Basin, U.S. Coal Relative to No-Action Alternative (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	-9.61	-192.2
4	Northern	Low	Medium	N, Low, Med	-3.29	-65.8
5	Northern	Low	High	N, Low, High	-11.79	-235.7
6	Northern	Medium	Zero	N, Med, Zero	-13.21	-264.2
7	Northern	Medium	Medium	N, Med, Med	-4.73	-94.7
8	Northern	Medium	High	N, Med, High	-12.66	-253.3
9	Northern	High	Zero	N, High, Zero	-15.13	-302.5
10	Northern	High	Medium	N, High, Med	-10.65	-213.1
11	Northern	High	High	N, High, High	-17.64	-352.9
12	Southern	Low	Zero	S, Low, Zero	-6.01	-120.1
13	Southern	Low	Medium	S, Low, Med	-3.83	-76.6
14	Southern	Low	High	S, Low, High	-11.83	-236.5
15	Southern	Medium	Zero	S, Med, Zero	-11.94	-238.7
16	Southern	Medium	Medium	S, Med, Med	-5.19	-103.9
17	Southern	Medium	High	S, Med, High	-12.79	-255.8
18	Southern	High	Zero	S, High, Zero	-15.04	-300.8
19	Southern	High	Medium	S, High, Med	-19.53	-390.6
20	Southern	High	High	S, High, High	-20.46	-409.1
21	Northern	Low	Zero	N, Low, Zero, Low Gas	-5.10	-102.0
22	Northern	Low	High	N, Low, High, Low Gas	-2.21	-44.2
23	Northern	Low	High	N, Low, High, Yes CO ₂	-4.79	-95.8

Table 10-15. Change in Carbon Dioxide Emissions from Total U.S. Coal Combusted Relative to No-Action Alternative (million metric tons)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO ₂ Emissions MMT CO ₂ /year	Total CO ₂ Emissions MMT CO ₂
3	Northern	Low	Zero	N, Low, Zero	0.38	7.6
4	Northern	Low	Medium	N, Low, Med	0.46	9.2
5	Northern	Low	High	N, Low, High	2.65	53.1
6	Northern	Medium	Zero	N, Med, Zero	1.16	23.3
7	Northern	Medium	Medium	N, Med, Med	2.46	49.2
8	Northern	Medium	High	N, Med, High	4.55	91.0
9	Northern	High	Zero	N, High, Zero	1.29	25.8
10	Northern	High	Medium	N, High, Med	3.36	67.2
11	Northern	High	High	N, High, High	6.16	123.2
12	Southern	Low	Zero	S, Low, Zero	0.47	9.4
13	Southern	Low	Medium	S, Low, Med	0.63	12.7
14	Southern	Low	High	S, Low, High	2.94	58.8
15	Southern	Medium	Zero	S, Med, Zero	0.77	15.4
16	Southern	Medium	Medium	S, Med, Med	1.66	33.1
17	Southern	Medium	High	S, Med, High	3.79	75.8
18	Southern	High	Zero	S, High, Zero	1.71	34.2
19	Southern	High	Medium	S, High, Med	3.31	66.2
20	Southern	High	High	S, High, High	6.63	132.7
21	Northern	Low	Zero	N, Low, Zero, Low Gas	2.49	49.7
22	Northern	Low	High	N, Low, High, Low Gas	2.20	44.0
23	Northern	Low	High	N, Low, High, Yes CO ₂	0.71	14.1

There are small differences between the change in CO₂ emissions from the coal and natural gas combustion results in Table 10-7 and the CO₂ emissions from the combustion of coal mined in the United States in Table 10-15. Three differences in the way the coal is accounted explain the differences in the results. First, there is a change in U.S. imports in some of the scenarios. Thus, there is a change in the coal consumption-based deltas that results in changes in domestic production in the opposite direction. For example, if imports increase in the Proposed Action then the U.S. coal consumption delta would increase, while the U.S. coal production delta would decrease, because there would be a corresponding decrease in U.S. production if imports increased. Second, there is a change in the heat content of the coal exported between the No-Action and Proposed Action scenarios, while the tons stay the same. This change is captured in the production-based method but not in the consumption based method. Third, there is a small change in the coal types consumed for industrial demand. The consumption data does not include emissions from industrial demand; however, the production data will include the change in coal types consumed.

10.3.3 Pacific Basin Carbon Dioxide Emissions from Coal

The annual changes in Pacific Basin emissions due to the proposed action would be smaller than the United States. CO₂ emissions changes for two reasons: First, the analysis only includes changes in total coal emissions and does not include changes in emissions from the consumption of natural gas. The analysis does not account for transportation and all other lifecycle emissions in the Pacific Basin, which is the same treatment as the U.S. emissions. Second, there would be very little change in overall coal consumption on an international level as one coal tends to replace another coal. Thus, the incremental change in coal consumption due to the proposed rail line would be small, which would result in a small change in CO₂ emissions.

The Pacific Basin average annual coal-related CO₂ emissions for all 21 primary sensitivity scenarios from 2018 to 2037 would be 14,704 million metric tons per year, which is 6.1 times higher than the U.S. coal and natural gas CO₂ emissions. Table 10-16 shows the total coal-related CO₂ emissions in the Pacific Basin. The results in Table 10-17 show the difference in CO₂ emissions between a No-Action Alternative scenario and a scenario with the Tongue River Railroad, all else equal, thereby isolating the impact of construction and operation of the proposed rail line on domestic and international markets. The annual average change in Pacific Basin CO₂ emissions would range from a decrease of 0.284 million metric tons per year to an increase of 0.332 million metric tons per year of CO₂ for the 21 primary sensitivity scenarios analyzed. The small decrease in Pacific Basin CO₂ emissions relative to the total Pacific Basin CO₂ emissions (less than 0.0001%) is the result of the model optimizing between coal types and shifting less than 5 million tons of coal consumption from subbituminous to bituminous coal. If bituminous coal replaces subbituminous coal in the Pacific Basin, CO₂ emissions would decrease because subbituminous coal has a higher CO₂ emissions rate (212.7 pounds of CO₂ per million British thermal units [MMBtu]) than bituminous coal (205.3 pounds of CO₂ per MMBtu).

Table 10-16. Pacific Basin Carbon Dioxide Emissions from Coal (million metric tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	13,009	14,047	15,207	16,540	14,701
4	Northern	Low	Medium	N, Low, Med	13,010	14,050	15,210	16,543	14,703
5	Northern	Low	High	N, Low, High	13,012	14,054	15,213	16,547	14,707
6	Northern	Medium	Zero	N, Med, Zero	13,009	14,047	15,207	16,540	14,701
7	Northern	Medium	Medium	N, Med, Med	13,010	14,050	15,210	16,543	14,703
8	Northern	Medium	High	N, Med, High	13,012	14,054	15,213	16,547	14,707
9	Northern	High	Zero	N, High, Zero	13,009	14,047	15,207	16,540	14,701
10	Northern	High	Medium	N, High, Med	13,010	14,050	15,210	16,543	14,703
11	Northern	High	High	N, High, High	13,012	14,054	15,213	16,547	14,707
12	Southern	Low	Zero	S, Low, Zero	13,009	14,047	15,207	16,540	14,701
13	Southern	Low	Medium	S, Low, Med	13,010	14,050	15,210	16,543	14,703
14	Southern	Low	High	S, Low, High	13,012	14,054	15,213	16,547	14,707
15	Southern	Medium	Zero	S, Med, Zero	13,009	14,047	15,207	16,540	14,701
16	Southern	Medium	Medium	S, Med, Med	13,010	14,050	15,210	16,543	14,703
17	Southern	Medium	High	S, Med, High	13,012	14,054	15,213	16,547	14,707
18	Southern	High	Zero	S, High, Zero	13,009	14,047	15,207	16,540	14,701
19	Southern	High	Medium	S, High, Med	13,010	14,050	15,210	16,543	14,704
20	Southern	High	High	S, High, High	13,012	14,054	15,214	16,547	14,707
21	Northern	Low	Zero	N, Low, Zero, Low Gas	13,009	14,047	15,207	16,540	14,701
22	Northern	Low	High	N, Low, High, Low Gas	13,012	14,054	15,213	16,547	14,707
23	Northern	Low	High	N, Low, High, Yes CO ₂	13,012	14,054	15,213	16,547	14,707
Average									14,704

Table 10-17. Change in Pacific Basin Carbon Dioxide Emissions from Coal from No-Action Alternative Scenarios (million metric tons per year)

Sce- nario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	Annual Average CO2 Emissions MMT CO2/year	Total CO2 Emissions MMT CO2
3	Northern	Low	Zero	N, Low, Zero	-0.004	-0.089
4	Northern	Low	Medium	N, Low, Med	-0.004	-0.079
5	Northern	Low	High	N, Low, High	-0.041	-0.826
6	Northern	Medium	Zero	N, Med, Zero	-0.002	-0.033
7	Northern	Medium	Medium	N, Med, Med	0.061	1.211
8	Northern	Medium	High	N, Med, High	0.057	1.146
9	Northern	High	Zero	N, High, Zero	-0.057	-1.135
10	Northern	High	Medium	N, High, Med	0.093	1.851
11	Northern	High	High	N, High, High	0.332	6.645
12	Southern	Low	Zero	S, Low, Zero	-0.004	-0.074
13	Southern	Low	Medium	S, Low, Med	0.005	0.098
14	Southern	Low	High	S, Low, High	-0.035	-0.695
15	Southern	Medium	Zero	S, Med, Zero	-0.005	-0.100
16	Southern	Medium	Medium	S, Med, Med	-0.001	-0.026
17	Southern	Medium	High	S, Med, High	0.028	0.554
18	Southern	High	Zero	S, High, Zero	-0.057	-1.138
19	Southern	High	Medium	S, High, Med	-0.115	-2.290
20	Southern	High	High	S, High, High	-0.284	-5.676
21	Northern	Low	Zero	N, Low, Zero, Low Gas	-0.004	-0.077
22	Northern	Low	High	N, Low, High, Low Gas	0.004	0.087
23	Northern	Low	High	N, Low, High, Yes CO ₂	-0.065	-1.302
Average					-0.005	-0.093

Across the 21 primary sensitivity scenarios, the change in Pacific Basin CO₂ emissions from the construction of the Tongue River Railroad averaged over 2018 to 2037 would range from a decrease of 0.284 to an increase to 0.332 million metric tons per year and would average a decrease of 0.005 million metric tons of CO₂ per year. Total Pacific Basin CO₂ emissions from the construction of the Tongue River Railroad over 2018 to 2037 would range from an increase of 6.645 to a decrease of 5.676 million metric tons and would average a decrease of 0.093 million metric tons of CO₂.

10.4 Sulfur Dioxide Emissions

This section presents the SO₂ emissions for the No-Action Alternative and proposed rail line scenarios.

10.4.1 Sulfur Dioxide Emissions under the No-Action Alternative

As with CO₂ emissions, the scope of this analysis included emissions from coal and natural gas-fired generators in the United States and from total coal consumption in the Pacific Basin. However, because SO₂ emissions from natural gas are negligible compared to the SO₂ emissions from coal, OEA assumed the SO₂ emissions reported here to be all from coal consumption. OEA estimated the SO₂ emissions from these sources under the No Action Alternative scenarios for the years 2018 to 2037 for both the United States and the Pacific Basin. Emissions of SO₂ from the consumption of coal in the Pacific Basin were included in OEA's analysis because a portion of the Tongue River coal may be exported to this region.

The annual U.S. coal and natural gas emissions of SO₂ from power plants under the six No-Action Alternative scenarios (scenarios 1, 2, 24, 25, 26, and 27) would range from 1,542 thousand to 1,736 thousand tons per year and would average 1,656 thousand tons from 2018 to 2037. The average annual Pacific Basin coal SO₂ emissions under the No-Action Alternative scenarios would range from 29,181 thousand tons per year (scenario 25) to 36,757 thousand tons per year (scenario 27) and would average 32,817 thousand tons from 2018 to 2037.

Table 10-18 presents the annual U.S. SO₂ emissions from coal and gas-fired generators for the six No-Action Alternative scenarios, and Table 10-19 shows the annual emissions from Pacific Basin coal consumption. On average, the Pacific Basin SO₂ emissions would be 19.8 times higher than U.S. SO₂ emissions, due to the much greater volume of coal consumed and the generally higher SO₂ emissions rates. As discussed in Section 10.2, *Emissions Assumptions*, OEA assumed the Pacific Basin SO₂ emissions rate to be higher because many of the coal plants in China are uncontrolled for SO₂, and those that are controlled tend to have lower reduction rates, which results in greater emissions.

Table 10-18. U.S. Sulfur Dioxide Emissions from Coal and Natural Gas-Fired Generators (thousand tons per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	1,593	1,671	1,747	1,829	1,710
25	No-Action Alternative	Medium	No TRR, Med	1,594	1,680	1,749	1,833	1,714
2	No-Action Alternative	High	No TRR, High	1,601	1,717	1,769	1,856	1,736
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	1,377	1,523	1,696	1,821	1,604
27	No-Action Alternative	High	No TRR, High, Low Gas	1,404	1,541	1,724	1,848	1,629
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	1,566	1,575	1,538	1,489	1,542
Average								1,656

Table 10-19. Pacific Basin Sulfur Dioxide Emissions from Coal (thousand tons per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	29,200	31,396	33,892	36,715	32,801
25	No-Action Alternative	Medium	No TRR, Med	29,181	31,388	33,877	36,690	32,784
2	No-Action Alternative	High	No TRR, High	29,217	31,455	33,928	36,743	32,836
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	29,200	31,396	33,892	36,715	32,801
27	No-Action Alternative	High	No TRR, High, Low Gas	29,217	31,455	33,942	36,744	32,839
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	29,217	31,455	33,939	36,757	32,842
Average								32,817

10.4.2 U.S. Sulfur Dioxide Emissions from Coal and Natural Gas-Fired Generation

SO₂ emissions would result from the consumption of Tongue River coal. As with CO₂ emissions, the total SO₂ emissions from Tongue River coal would depend on changes in total coal consumption, as well as changes in the sulfur content of the mix of coals consumed. For example, because the Powder River Basin coal has lower average sulfur content than most other coals, overall SO₂ emissions may decrease as Powder River Basin coal displaces other coals. However, since Tongue River coal would mostly displace other low-sulfur Powder River Basin coal, this effect would result in only minor changes in SO₂ estimates.

Table 10-20 shows total U.S. SO₂ emissions from coal and natural gas-fired electric generators for each scenario. The average annual SO₂ emissions over all 21 primary sensitivity scenarios would range from 1,539 to 1,729 thousand tons and would average 1,691 thousand tons per year. The range of SO₂ emissions for individual years is 1,378 thousand tons per year (scenario 21 in 2018) to 1,848 thousand tons per year (scenario 14 in 2037). Table 10-21 shows the change in U.S. SO₂ emissions that would result from the development of the proposed rail line.

Table 10-20. U.S. Sulfur Dioxide Emissions from Coal and Natural Gas (thousand tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	1,589	1,666	1,717	1,815	1,697
4	Northern	Low	Medium	N, Low, Med	1,590	1,680	1,754	1,829	1,713
5	Northern	Low	High	N, Low, High	1,599	1,693	1,774	1,847	1,728
6	Northern	Medium	Zero	N, Med, Zero	1,589	1,662	1,716	1,810	1,694
7	Northern	Medium	Medium	N, Med, Med	1,591	1,675	1,745	1,827	1,709
8	Northern	Medium	High	N, Med, High	1,601	1,688	1,765	1,844	1,724
9	Northern	High	Zero	N, High, Zero	1,588	1,656	1,706	1,809	1,690
10	Northern	High	Medium	N, High, Med	1,586	1,668	1,718	1,821	1,698
11	Northern	High	High	N, High, High	1,594	1,684	1,749	1,842	1,717
12	Southern	Low	Zero	S, Low, Zero	1,589	1,668	1,722	1,828	1,702
13	Southern	Low	Medium	S, Low, Med	1,591	1,680	1,757	1,830	1,714
14	Southern	Low	High	S, Low, High	1,600	1,694	1,774	1,848	1,729
15	Southern	Medium	Zero	S, Med, Zero	1,589	1,665	1,713	1,813	1,695
16	Southern	Medium	Medium	S, Med, Med	1,590	1,675	1,750	1,831	1,711
17	Southern	Medium	High	S, Med, High	1,601	1,689	1,767	1,847	1,726
18	Southern	High	Zero	S, High, Zero	1,587	1,658	1,708	1,803	1,689
19	Southern	High	Medium	S, High, Med	1,586	1,667	1,714	1,809	1,694
20	Southern	High	High	S, High, High	1,595	1,682	1,750	1,828	1,714
21	Northern	Low	Zero	N, Low, Zero, Low Gas	1,378	1,519	1,691	1,815	1,601
22	Northern	Low	High	N, Low, High, Low Gas	1,396	1,543	1,724	1,841	1,626
23	Northern	Low	High	N, Low, High, Yes CO2	1,555	1,572	1,542	1,488	1,539
Average									1,691

Table 10-21. Change in U.S. Sulfur Dioxide Emissions from Coal and Natural Gas Relative to the No-Action Alternative Scenarios (thousand tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	-4.9	-5.0	-29.8	-13.9	-13.4
4	Northern	Low	Medium	N, Low, Med	-3.9	0.4	4.6	-4.2	-0.8
5	Northern	Low	High	N, Low, High	-2.1	-23.9	4.8	-9.4	-7.7
6	Northern	Medium	Zero	N, Med, Zero	-4.7	-9.6	-30.2	-18.1	-15.7
7	Northern	Medium	Medium	N, Med, Med	-2.9	-5.3	-4.6	-6.1	-4.7
8	Northern	Medium	High	N, Med, High	0.1	-29.0	-4.6	-12.6	-11.5
9	Northern	High	Zero	N, High, Zero	-5.1	-15.2	-40.2	-20.0	-20.1
10	Northern	High	Medium	N, High, Med	-7.4	-11.6	-31.4	-12.0	-15.6
11	Northern	High	High	N, High, High	-6.7	-33.5	-20.0	-14.3	-18.6
12	Southern	Low	Zero	S, Low, Zero	-4.5	-3.6	-25.1	-0.4	-8.4
13	Southern	Low	Medium	S, Low, Med	-3.1	0.5	7.4	-3.3	0.4
14	Southern	Low	High	S, Low, High	-0.4	-23.6	4.4	-8.1	-7.0
15	Southern	Medium	Zero	S, Med, Zero	-4.9	-6.5	-34.0	-15.4	-15.2
16	Southern	Medium	Medium	S, Med, Med	-3.5	-5.1	0.8	-2.4	-2.6
17	Southern	Medium	High	S, Med, High	0.0	-28.6	-2.2	-8.8	-9.9
18	Southern	High	Zero	S, High, Zero	-6.6	-13.0	-38.3	-25.7	-20.9
19	Southern	High	Medium	S, High, Med	-7.5	-12.5	-35.4	-24.0	-19.9
20	Southern	High	High	S, High, High	-5.2	-35.7	-19.5	-28.3	-22.2
21	Northern	Low	Zero	N, Low, Zero, Low Gas	0.8	-3.4	-5.1	-5.5	-3.3
22	Northern	Low	High	N, Low, High, Low Gas	-7.4	2.5	0.3	-7.7	-3.1
23	Northern	Low	High	N, Low, High, Yes CO2	-10.3	-2.8	4.4	-1.3	-2.5
Average									-10.6

OEA found that the net changes in U.S. SO₂ emissions related to consumption of Tongue River coal would be small compared to total U.S. SO₂ emissions, with increases being less than 0.5% and decreases being less than 2.5%. Of the 21 scenarios analyzed, only one, Scenario 13, would have an average annual net increase in U.S. SO₂ emissions of 0.4 thousand tons. The maximum increase in any one year would be 7.4 thousand tons in Scenario 13 in 2030. The change in annual SO₂ emissions over all 21 scenarios ranged from

a decrease of 22.2 thousand tons to an increase of 0.4 thousand tons and averaged a decrease of 10.6 thousand tons per year from 2018 to 2037.

10.4.3 Pacific Basin Sulfur Dioxide Emissions from Coal

The annual changes in Pacific Basin emissions would be similar to U.S. SO₂ emissions changes for two reasons. First, the amount of coal shifting between the proposed rail line scenarios and No-Action Alternative scenarios would be similar. Second, one coal would tend to replace another coal, with very little change in coal consumption on an international level. Transportation and all other lifecycle emissions are not accounted for in the Pacific Basin SO₂ emissions, which is the same treatment as the U.S. emissions.

The Pacific Basin average annual coal-related SO₂ emissions for all 21 scenarios from 2018 to 2037 would be 32,804 thousand tons per year, which is 19.4 times the U.S. coal and natural gas SO₂ emissions. Table 10-22 shows the total coal-related SO₂ emissions in the Pacific Basin.

The results in Table 10-23 show the difference in SO₂ emissions between a No-Action Alternative scenario and a proposed rail line scenario, all else equal, thereby isolating the impact of construction and operation of the proposed rail line on domestic and international markets. The annual average change in Pacific Basin SO₂ emissions would range from a decrease of 53.8 thousand tons per year to an increase of 2.1 thousand tons per year of SO₂ for the 21 primary sensitivity scenarios analyzed.

OEA found that the net changes in Pacific Basin SO₂ emissions related to consumption of Tongue River coal would be small compared to total Pacific Basin SO₂ emissions, with increases being less than 0.041% and decreases being less than 0.258%. The maximum increase in any one year would be 13.3 thousand tons (scenario 5 in 2030), and the maximum decrease in any one year would be 84.7 thousand tons (scenario 20 in 2030).

The changes in Pacific Basin SO₂ emissions would be a result of the changes in the coals being consumed that have different sulfur contents. Note that the SO₂ emissions would be lower if there were international SO₂ allowance prices that could be modeled, as these prices would favor lower sulfur coals.

Table 10-22. Pacific Basin Sulfur Dioxide Emissions from Coal (thousand tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	29,200	31,396	33,892	36,715	32,801
4	Northern	Low	Medium	N, Low, Med	29,181	31,388	33,877	36,690	32,784
5	Northern	Low	High	N, Low, High	29,217	31,455	33,942	36,737	32,838
6	Northern	Medium	Zero	N, Med, Zero	29,200	31,396	33,892	36,715	32,801
7	Northern	Medium	Medium	N, Med, Med	29,181	31,382	33,862	36,692	32,779
8	Northern	Medium	High	N, Med, High	29,217	31,444	33,925	36,734	32,830
9	Northern	High	Zero	N, High, Zero	29,200	31,396	33,892	36,715	32,801
10	Northern	High	Medium	N, High, Med	29,182	31,361	33,860	36,692	32,773
11	Northern	High	High	N, High, High	29,209	31,406	33,894	36,711	32,805
12	Southern	Low	Zero	S, Low, Zero	29,200	31,396	33,892	36,715	32,801
13	Southern	Low	Medium	S, Low, Med	29,181	31,388	33,874	36,690	32,783
14	Southern	Low	High	S, Low, High	29,217	31,455	33,939	36,740	32,838
15	Southern	Medium	Zero	S, Med, Zero	29,200	31,396	33,892	36,715	32,801
16	Southern	Medium	Medium	S, Med, Med	29,181	31,388	33,876	36,690	32,784
17	Southern	Medium	High	S, Med, High	29,217	31,447	33,929	36,737	32,833
18	Southern	High	Zero	S, High, Zero	29,200	31,396	33,892	36,715	32,801
19	Southern	High	Medium	S, High, Med	29,181	31,385	33,849	36,688	32,776
20	Southern	High	High	S, High, High	29,217	31,406	33,844	36,661	32,782
21	Northern	Low	Zero	N, Low, Zero, Low Gas	29,200	31,396	33,892	36,715	32,801
22	Northern	Low	High	N, Low, High, Low Gas	29,217	31,455	33,942	36,735	32,837
23	Northern	Low	High	N, Low, High, Yes CO ₂	29,217	31,455	33,939	36,757	32,842
Average									32,804

Table 10-23. Change in Pacific Basin Sulfur Dioxide Emissions from Coal from No-Action Alternative Scenarios (thousand tons per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	0.0	0.0	0.0	0.0	0.0
4	Northern	Low	Medium	N, Low, Med	0.0	0.0	0.0	0.0	0.0
5	Northern	Low	High	N, Low, High	0.0	0.0	13.3	-5.9	1.9
6	Northern	Medium	Zero	N, Med, Zero	0.0	0.0	0.0	0.0	0.0
7	Northern	Medium	Medium	N, Med, Med	0.0	-6.1	-14.6	1.5	-4.8
8	Northern	Medium	High	N, Med, High	0.0	-10.9	-3.4	-8.3	-5.7
9	Northern	High	Zero	N, High, Zero	0.0	0.0	0.0	0.0	0.0
10	Northern	High	Medium	N, High, Med	0.6	-26.9	-17.0	1.5	-10.4
11	Northern	High	High	N, High, High	-7.6	-48.5	-34.8	-32.1	-30.8
12	Southern	Low	Zero	S, Low, Zero	0.0	0.0	0.0	0.0	0.0
13	Southern	Low	Medium	S, Low, Med	0.0	0.0	-2.2	0.0	-0.6
14	Southern	Low	High	S, Low, High	0.0	0.0	11.0	-2.7	2.1
15	Southern	Medium	Zero	S, Med, Zero	0.0	0.0	0.0	0.0	0.0
16	Southern	Medium	Medium	S, Med, Med	0.0	0.0	-1.0	0.0	-0.3
17	Southern	Medium	High	S, Med, High	0.0	-7.8	0.9	-5.8	-3.2
18	Southern	High	Zero	S, High, Zero	0.0	0.0	0.0	0.0	0.0
19	Southern	High	Medium	S, High, Med	0.0	-2.8	-28.0	-2.1	-8.2
20	Southern	High	High	S, High, High	0.0	-48.5	-84.7	-82.0	-53.8
21	Northern	Low	Zero	N, Low, Zero, Low Gas	0.0	0.0	0.0	0.0	0.0
22	Northern	Low	High	N, Low, High, Low Gas	0.0	0.0	0.0	-9.1	-2.3
23	Northern	Low	High	N, Low, High, Yes CO ₂	0.0	0.0	-0.2	-0.4	-0.1
Average									-5.5

10.5 Mercury Emissions

This section presents the mercury emissions for the proposed rail line scenarios and No-Action Alternative scenarios.

10.5.1 Mercury Emissions under the No-Action Alternative

As with CO₂ emissions, the scope of this analysis included emissions from coal and natural gas-fired generators in the United States and from total coal consumption in the Pacific Basin. However, the mercury emissions from natural gas are small (0.04%) compared to the mercury emissions from coal, and thus the mercury emissions reported here can be assumed to be all from coal consumption. OEA estimated the mercury emissions from these sources under the No-Action Alternative scenarios for the years 2018 to 2037 for both the United States and the Pacific Basin. OEA included emissions for mercury from the consumption of coal in the Pacific Basin in this analysis because a portion of Tongue River coal is likely to be exported to this region.

The annual U.S. coal and natural gas emissions of mercury from power plants under the six No-Action Alternative scenarios (scenarios 1, 2, 24, 25, 26, and 27) would range from 12,315 pounds per year (scenario 24) to 13,670 pounds per year (scenario 2) and would average 13,150 pounds per year from 2018 to 2037. The annual Pacific Basin coal mercury emissions under the six No-Action Alternative scenarios would range from 882,281 pounds per year (scenario 24) to 1,104,471 pounds per year (scenario 1) and would average 987,958 pounds from 2018 to 2037.

Table 10-24 shows the annual U.S. mercury emissions from coal and gas-fired generators for the six No-Action Alternative scenarios; Table 10-25 shows Pacific Basin coal consumption, with averages are calculated from 2018 to 2037. The analysis shows that on average, the Pacific Basin mercury emissions would be 73 times higher than U.S. mercury emissions, due to the much greater volume of coal that would be consumed and the generally higher mercury emissions rates in countries such as China, where power plants are less controlled for environmental pollutants.

Table 10-24. U.S. Mercury Emissions from Coal and Natural Gas-Fired Generators (pounds per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	12,699	13,363	13,562	14,634	13,564
2	No-Action Alternative	High	No TRR, High	12,736	13,531	13,673	14,739	13,670
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	12,615	12,727	12,124	11,797	12,315
25	No-Action Alternative	Medium	No TRR, Med	12,703	13,375	13,537	14,648	13,566
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	10,807	12,171	13,440	14,974	12,848
27	No-Action Alternative	High	No TRR, High, Low Gas	10,884	12,277	13,517	15,079	12,939
Average								13,150

Table 10-25. Pacific Basin Mercury Emissions from Coal (pounds per year)

Scenario	Alternative	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
1	No-Action Alternative	Zero	No TRR, Zero	886,242	951,710	1,025,523	1,104,473	991,987
2	No-Action Alternative	High	No TRR, High	882,282	944,132	1,017,706	1,096,587	985,177
24	No-Action Alternative	High	No TRR, High, Yes CO ₂	882,281	944,132	1,017,808	1,096,770	985,248
25	No-Action Alternative	Medium	No TRR, Med	884,186	947,697	1,021,420	1,100,338	988,410
26	No-Action Alternative	Zero	No TRR, Zero, Low Gas	886,242	951,710	1,025,523	1,104,473	991,987
27	No-Action Alternative	High	No TRR, High, Low Gas	882,281	944,132	1,017,834	1,096,608	985,214
Average								988,004

10.5.2 U.S. Mercury Emissions from Coal and Natural Gas-Fired Generation

Table 10-26 shows the total annual U.S. mercury emissions from coal and natural gas-fired electric generators for each scenario. The annual mercury emissions over all 21 primary sensitivity scenarios would range from 10,825 pounds (scenario 21) to 15,095 pounds (scenario 22) and would average 13,493 pounds from 2018 to 2037. Table 10-27 shows the change in U.S. mercury emissions from the development of the proposed rail line as compared to the No-Action Alternative.

OEA found that the net changes in U.S. mercury emissions resulting from Tongue River coal would be small compared to total U.S. mercury emissions, with increases of less than 0.4% and decreases of less than 0.1%. All but two of the 21 primary sensitivity scenarios would have an average annual net increase in U.S. mercury emissions (Table 10-26). The change in annual mercury emissions over all 21 primary sensitivity scenarios would range from a decrease of 12.3 pounds (scenario 20) to an increase of 45.3 pounds (scenario 16), and would average an increase of 21.5 pounds from 2018 to 2037.

Domestic mercury emissions would increase under most scenarios, with the exception of the two high growth scenarios (scenarios 11 and 20). The maximum increase in domestic mercury emissions would average 45.3 pounds per year from 2018 to 2037 (scenario 16) and would be correlated to the overall increase in domestic coal consumption. The maximum decrease in domestic mercury emissions would be 12.3 pounds per year (scenario 20). Mercury is found in significantly higher concentrations in coal compared to natural gas; thus, changes in natural gas consumption would not materially affect overall mercury emissions, all else being equal.

The average changes in Pacific Basin mercury emissions would range from a decrease of 550 pounds per year to an increase of 18 pounds per year.

Table 10-26. U.S. Mercury Emissions from Coal and Natural Gas (pounds per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	12,701	13,365	13,564	14,636	13,566
4	Northern	Low	Medium	N, Low, Med	12,734	13,406	13,568	14,679	13,597
5	Northern	Low	High	N, Low, High	12,753	13,549	13,691	14,757	13,688
6	Northern	Medium	Zero	N, Med, Zero	12,706	13,371	13,569	14,641	13,572
7	Northern	Medium	Medium	N, Med, Med	12,735	13,407	13,569	14,680	13,598
8	Northern	Medium	High	N, Med, High	12,753	13,549	13,691	14,757	13,688
9	Northern	High	Zero	N, High, Zero	12,713	13,377	13,576	14,648	13,578
10	Northern	High	Medium	N, High, Med	12,733	13,405	13,567	14,677	13,595
11	Northern	High	High	N, High, High	12,733	13,528	13,670	14,737	13,667
12	Southern	Low	Zero	S, Low, Zero	12,717	13,381	13,580	14,651	13,582
13	Southern	Low	Medium	S, Low, Med	12,748	13,420	13,582	14,692	13,610
14	Southern	Low	High	S, Low, High	12,772	13,567	13,709	14,775	13,706
15	Southern	Medium	Zero	S, Med, Zero	12,717	13,381	13,580	14,652	13,583
16	Southern	Medium	Medium	S, Med, Med	12,748	13,420	13,582	14,693	13,611
17	Southern	Medium	High	S, Med, High	12,764	13,559	13,701	14,768	13,698
18	Southern	High	Zero	S, High, Zero	12,722	13,387	13,585	14,657	13,588
19	Southern	High	Medium	S, High, Med	12,739	13,411	13,573	14,684	13,602
20	Southern	High	High	S, High, High	12,723	13,519	13,660	14,727	13,657
21	Northern	Low	Zero	N, Low, Zero, Low Gas	10,825	12,189	13,457	14,992	12,866
22	Northern	Low	High	N, Low, High, Low Gas	10,900	12,293	13,533	15,095	12,955
23	Northern	Low	High	N, Low, High, Yes CO ₂	12,644	12,756	12,153	11,826	12,345
Average									13,493

Table 10-27. Change in U.S. Mercury Emissions from Coal and Natural Gas Relative to the No-Action Alternative Scenarios (pounds per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	2.1	2.1	2.1	2.1	2.1
4	Northern	Low	Medium	N, Low, Med	31.6	31.6	31.6	31.6	31.6
5	Northern	Low	High	N, Low, High	18.0	18.0	18.0	18.0	18.0
6	Northern	Medium	Zero	N, Med, Zero	7.7	7.7	7.7	7.7	7.7
7	Northern	Medium	Medium	N, Med, Med	32.4	32.4	32.4	32.4	32.4
8	Northern	Medium	High	N, Med, High	17.9	17.9	17.9	17.9	17.9
9	Northern	High	Zero	N, High, Zero	14.1	14.1	14.1	14.1	14.1
10	Northern	High	Medium	N, High, Med	29.9	29.9	29.9	29.9	29.9
11	Northern	High	High	N, High, High	-2.5	-2.5	-2.5	-2.5	-2.5
12	Southern	Low	Zero	S, Low, Zero	17.9	17.9	17.9	17.9	17.9
13	Southern	Low	Medium	S, Low, Med	44.7	44.7	44.7	44.7	44.7
14	Southern	Low	High	S, Low, High	36.1	36.1	36.1	36.1	36.1
15	Southern	Medium	Zero	S, Med, Zero	18.4	18.4	18.4	18.4	18.4
16	Southern	Medium	Medium	S, Med, Med	45.3	45.3	45.3	45.3	45.3
17	Southern	Medium	High	S, Med, High	28.2	28.2	28.2	28.2	28.2
18	Southern	High	Zero	S, High, Zero	23.6	23.6	23.6	23.6	23.6
19	Southern	High	Medium	S, High, Med	36.0	36.0	36.0	36.0	36.0
20	Southern	High	High	S, High, High	-12.3	-12.3	-12.3	-12.3	-12.3
21	Northern	Low	Zero	N, Low, Zero, Low Gas	17.9	17.9	17.9	17.9	17.9
22	Northern	Low	High	N, Low, High, Low Gas	15.9	15.9	15.9	15.9	15.9
23	Northern	Low	High	N, Low, High, Yes CO2	29.2	29.2	29.2	29.2	29.2
Average									21.5

10.5.3 Pacific Basin Mercury Emissions from Coal

The annual changes in Pacific Basin mercury emissions tend to be larger than the U.S. mercury emissions changes, because of the larger volume of coal being consumed. However, the average over all 21 primary sensitivity scenarios is less because more of the scenarios show a decrease in mercury emissions, which brings down the average.

The average annual Pacific Basin coal-related mercury emissions for all 21 primary sensitivity scenarios from 2018 to 2037 would be 988,004 pounds per year, which is

73.2 times the U.S. coal and natural gas mercury emissions. Table 10-28 shows the total coal-related mercury emissions in the Pacific Basin.

The results in Table 10-29 show the difference in mercury emissions between a No-Action Alternative scenario and a proposed rail line scenario, all else equal, thereby isolating the impact of the proposed rail line on domestic and international markets. The annual average change in Pacific Basin mercury emissions would range from a decrease of 550 pounds per year to an increase of 18 pounds per year of mercury for the 21 primary sensitivity scenarios analyzed.

OEA found that the net changes in Pacific Basin mercury emissions related to consumption of Tongue River coal would be small compared to total Pacific Basin mercury emissions, with increases being less than 0.01% and decreases being less than 0.10%. The maximum increase in any one year would be 129 pounds (scenario 5 in 2030), and the maximum decrease in any one year would be 958 pounds (scenario 19 in 2030).

The changes in Pacific Basin mercury emissions would be a result of the changes in the coal being consumed that has different mercury contents. In the future, if additional controls were installed on coal-fired power plants in the Pacific Basin to reduce the emissions rate for mercury, it would reduce the amount of mercury estimated to be released in all scenarios. For example, if the Pacific Basin mercury reduction factor is 90%, which is what OEA estimated for the United States, the average change in mercury emissions over all 21 primary sensitivity scenarios would be decreased by 13.4 pounds instead of 67.2 pounds, and the maximum single-year increase would be 25.8 pounds instead of 129 pounds. To be conservative, this analysis assumes no new emissions controls would be installed.

Table 10-28. Pacific Basin Mercury Emissions from Coal (thousand pounds per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	886.24	951.71	1,025.52	1,104.47	991.99
4	Northern	Low	Medium	N, Low, Med	884.19	947.70	1,021.42	1,100.34	988.41
5	Northern	Low	High	N, Low, High	882.28	944.13	1,017.84	1,096.51	985.19
6	Northern	Medium	Zero	N, Med, Zero	886.24	951.71	1,025.52	1,104.47	991.99
7	Northern	Medium	Medium	N, Med, Med	884.19	947.64	1,021.28	1,100.36	988.37
8	Northern	Medium	High	N, Med, High	882.28	944.02	1,017.67	1,096.51	985.12
9	Northern	High	Zero	N, High, Zero	886.24	951.51	1,024.76	1,104.47	991.75
10	Northern	High	Medium	N, High, Med	884.19	947.43	1,021.25	1,100.36	988.31
11	Northern	High	High	N, High, High	882.21	943.66	1,017.37	1,096.32	984.89
12	Southern	Low	Zero	S, Low, Zero	886.24	951.71	1,025.52	1,104.47	991.99
13	Southern	Low	Medium	S, Low, Med	884.19	947.70	1,021.40	1,100.34	988.40
14	Southern	Low	High	S, Low, High	882.28	944.13	1,017.81	1,096.55	985.19
15	Southern	Medium	Zero	S, Med, Zero	886.24	951.71	1,025.52	1,104.47	991.99
16	Southern	Medium	Medium	S, Med, Med	884.19	947.70	1,021.41	1,100.34	988.41
17	Southern	Medium	High	S, Med, High	882.28	944.06	1,017.71	1,096.51	985.14
18	Southern	High	Zero	S, High, Zero	886.24	951.71	1,025.52	1,104.47	991.99
19	Southern	High	Medium	S, High, Med	884.19	947.59	1,021.23	1,100.34	988.33
20	Southern	High	High	S, High, High	882.28	943.65	1,016.81	1,095.76	984.63
21	Northern	Low	Zero	N, Low, Zero, Low Gas	886.24	951.71	1,025.52	1,104.47	991.99
22	Northern	Low	High	N, Low, High, Low Gas	882.28	944.13	1,017.83	1,096.49	985.18
23	Northern	Low	High	N, Low, High, Yes CO ₂	882.28	944.13	1,017.81	1,096.77	985.25
Average									988.31

Table 10-29. Change in Pacific Basin Mercury Emissions from Coal from No-Action Alternative Scenarios (pounds per year)

Scenario	Alternative	Tongue River Coal Production	Terminal Capacity Growth	Chart Label	2018	2023	2030	2037	Avg.
3	Northern	Low	Zero	N, Low, Zero	0.0	0.0	0.0	0.0	0.0
4	Northern	Low	Medium	N, Low, Med	0.0	-0.1	0.0	0.0	0.0
5	Northern	Low	High	N, Low, High	-0.9	0.0	129.2	-77.3	12.7
6	Northern	Medium	Zero	N, Med, Zero	0.0	0.0	0.0	0.0	0.0
7	Northern	Medium	Medium	N, Med, Med	0.0	-59.9	-141.8	23.1	-44.6
8	Northern	Medium	High	N, Med, High	-0.9	-106.6	-33.8	-72.8	-53.5
9	Northern	High	Zero	N, High, Zero	0.0	0.0	0.0	0.0	0.0
10	Northern	High	Medium	N, High, Med	6.8	-264.3	-168.8	23.1	-100.8
11	Northern	High	High	N, High, High	-74.9	-475.7	-338.0	-269.2	-289.5
12	Southern	Low	Zero	S, Low, Zero	0.0	0.0	0.0	0.0	0.0
13	Southern	Low	Medium	S, Low, Med	0.0	0.0	-21.7	0.0	-5.4
14	Southern	Low	High	S, Low, High	-0.9	0.0	106.9	-34.3	17.9
15	Southern	Medium	Zero	S, Med, Zero	0.0	0.0	0.0	0.0	0.0
16	Southern	Medium	Medium	S, Med, Med	0.0	-0.1	-9.8	0.0	-2.5
17	Southern	Medium	High	S, Med, High	-0.8	-75.1	8.8	-77.4	-36.1
18	Southern	High	Zero	S, High, Zero	0.0	0.0	0.0	0.0	0.0
19	Southern	High	Medium	S, High, Med	0.0	-200.8	-957.9	-149.3	-327.0
20	Southern	High	High	S, High, High	-0.9	-477.0	-896.4	-825.4	-549.9
21	Northern	Low	Zero	N, Low, Zero, Low Gas	0.0	0.0	0.0	0.0	0.0
22	Northern	Low	High	N, Low, High, Low Gas	0.0	0.0	0.3	-120.7	-30.1
23	Northern	Low	High	N, Low, High, Yes CO ₂	-0.3	0.0	-1.7	-4.1	-1.5
Average									-67.2

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ATTACHMENT A

Sodium Analysis of Tongue River Coal Deposits

Sodium Analysis of Tongue River Coal Deposits

Tongue River Coal Deposits

The sodium content of coal is stated as the percentage of sodium oxide (Na_2O) in the coal ash (though the actual measurement is sodium oxide, the result is often referred to as *sodium content*). The Tongue River coal deposits included in this analysis are the Otter Creek Mine, Poker Jim Creek-O'Dell Creek deposit, and Canyon Creek deposit. Additional details on these deposits can be found in Section 3.2.3, *Proposed and Potentially Induced Mines*. Sodium is approximately 7.4% of the Otter Creek coal ash, 6.5% of the Poker Jim Creek-O'Dell Creek coal ash, and 4.8% of the Canyon Creek coal ash; whereas, the average percentage of sodium for 13 Wyoming Powder River Basin mines reported in the *Guide to Coal Mines Served by the BNSF Railway* (BNSF Mine Guide) (BNSF Railway 2013, Matson and Blumer 1973, Norwest 2006) is 1.5%. This characteristic is often cited as one of the reasons why Tongue River coal deposits may not be readily accepted in the market place. High sodium content tends to cause undesirable accumulation of ash in parts of boilers burning such coal. Nonetheless, a number of power plant operators do use coal with sodium content similar to the Tongue River coal deposits. The feasibility of using this coal depends on the specifics of the design and operation of each power plant boiler and the preferences of the operators. Sodium content concerns apply in both the domestic and export markets; however, in the export market, the coal is often a small part of a large blend of many coals and is of less concern in terms of boiler impact.

The coal contained in the Otter Creek Mine is similar to coal from other mines in Montana and Wyoming except that it has a high sodium content—a characteristic shared by only a few other mines in Montana, including Spring Creek. In this context, *high sodium* means relative to other Powder River Basin coals. The quality of Otter Creek coal is compared to other Wyoming and Montana coals in Table A-1. Of particular note is the similar sodium content of the Otter Creek Mine to the coal from the Spring Creek mine, which has been in operation for many years. The energy content of Wyoming Powder River Basin coals ranges from the 8,500 British thermal units per pound (Btu/lb) coal shown for Otter Creek Mine to over 8,800 Btu/lb coal for Black Thunder Mine. Spring Creek coal has higher energy content than the Wyoming Powder River Basin coals.

Table A-1. Comparison of Quality Characteristics of Otter Creek Coal to Representative Competing Coal

	Central Appalachia	Illinois Basin	Powder River Basin Black Thunder	Powder River Basin Spring Creek	Otter Creek	Poker Jim Creek- O'Dell Creek	Canyon Creek
Btu/lb	12,500	11,800	8,943	9,350	8,600	8,758	9,110
Sulfur %	1	2.5	0.23	0.34	0.27	0.25	0.33
SO ₂ /MMBtu	1.65	4.10	0.51	0.73	0.64	0.58	0.72
Ash %	11.5	8	5	4.1			
Moisture %	7	12	26				
Fe ₂ O ₃	8.4	18	6	7.5			
CaO	2.3	2	23	15			
MgO	1.4	0.8	5	4			
Na ₂ O	0.7	1.2	1.4	7.4	7.4	6.5	4.8
K ₂ O	3.3	1.7	0.6	0.9			
SiO ₂	52	51	33	33			
Al ₂ O ₃	26.3	22	16	13			
TiO ₂	1	1	1.3	1.6			
Base to Acid (B/A) Ratio	0.20	0.32	0.72	0.73	No data	No data	No data
Fouling Index ^a	0.14	0.38	1.00	5.41	No data	No data	No data

Sources: Tillman et al. 2009; ICAP Energy 2013; Babcock & Wilcox 2005; Cloud Peak Energy 2013; Matson and Blumer 1973; Norwest 2006.

^a The Fouling Index is an index that can be calculated from the ash analysis and, give an indication of the propensity for that coal to cause fouling problems during combustion (Evolution Markets, Inc. 2013).

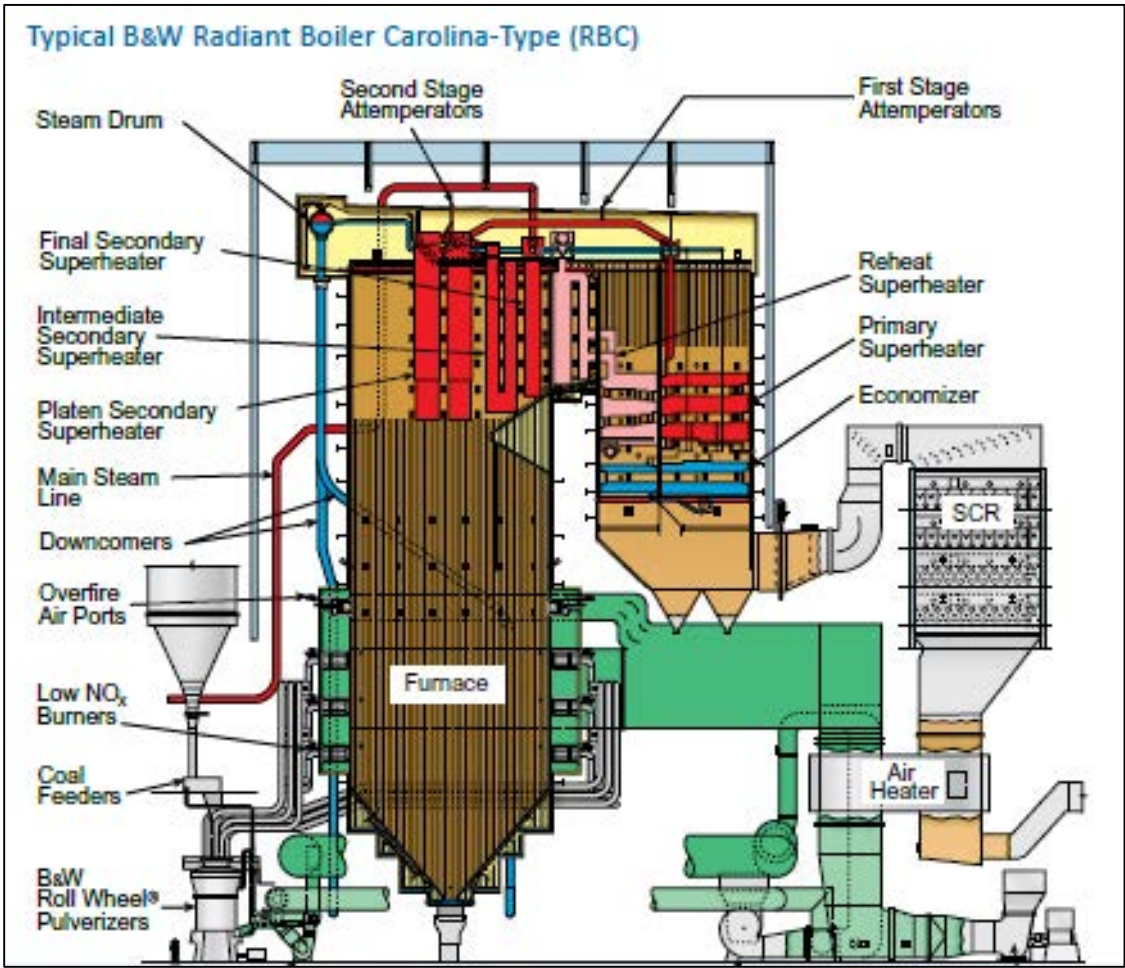
According to the BNSF Mine Guide, Decker Mine has a sodium content of 1.0% to 8.0%, Signal Peak Mine has a sodium content of 7.0%, and Spring Creek Mine has a sodium content of 8.2%. Two other Montana mines listed have much lower sodium content, thus, the Tongue River coal deposits are not unique. However, only a few other Powder River Basin mines have similarly high sodium content.

Effects of Sodium on Boiler Operation

When coal is burned in a pulverized coal-fired boiler, the flame is hot enough to melt or even vaporize all the minerals in the coal. Coal-fired boilers are designed so that the ash minerals cool in the main furnace. The heat is radiated away from the flame sufficiently, so that the ash becomes a nonsticky solid by the time the hot gasses reach the top of the boiler. The main furnace is shown in brown in Figure A-1. In practice, depending on the details of the boiler design and its interaction with the particular coal being burned, some ash may still be so hot that it forms slag or fouling deposits. *Slag* is molten ash that is usually associated with wall and furnace deposits. *Fouling* is the accumulation of softer ash deposits on tube surfaces. Fouling occurs in the convection pass; the area shown on the right-hand side of the diagram, which includes the reheat superheater, primary superheater, and economizer. In this

section of the boiler, flue gas passes directly over banks of tubes. Sodium deposits can be slag (molten) or sticky even at the cooler temperatures of the convection pass. This is why sodium in the coal contributes to fouling of the boiler tubes. Depending on the boiler design, sodium can also worsen slag accumulation in the boiler, since it effectively lowers the melting point of the surface of the ash particles. Boilers can be specifically designed to burn high-sodium coal. For example, by increasing the size of the boiler to allow the combustion gasses to cool sufficiently, the ash solidifies completely and provides wider-than-normal spacing of boiler tubes in the downstream portions of the boiler. A large boiler allows for radiant cooling of the combustion gas before it meets tube surfaces at the top of the furnace and the downstream passes. Boilers built specifically to burn Powder River Basin coal or lignite coal generally have a higher volume and are taller for a given output than boilers designed for higher-quality coal.

Figure A-1. Representative Coal-fired Boiler Design



Source: Babcock & Wilcox Power Generation Group.

Measures to Ameliorate Effects of High Sodium

Some specific measures may be taken by consumers of high-sodium coal to reduce fouling in the boiler. One of these measures is adding clay. As described by Hatt (2013),

Some experience has been had with high levels of kaolin type clay addition, which when used in 5% to 10% clay/coal additions has made a less sticky ash. You can imagine if there are so many more particles to coat, the sodium layer would be thinner, and the particle less sticky.

Modifications to the boiler may also reduce the effects of fouling. For example, the convection section can be modified to increase tube spacing and more “soot blowing” equipment can be added.

To predict the effect of sodium and other coal quality characteristics on ash behavior in the boiler, there are several well-recognized slagging calculations that can be performed. These calculations use the results of the ASTM Major and Minor Elemental or ash chemistry test. The following is excerpted from Hatt (2013).

The simplest is the base to acid ratio, (B/A) that compares the amount of basic (or fluxing/bonding) elements to the acidic (or glass formers/bulk) elements.

$$\text{B/A} = \frac{\text{Sum of bases}}{\text{sum of acids}} = \frac{(\text{Fe}_2\text{O}_3 + \text{CaO} + \text{MgO} + \text{K}_2\text{O} + \text{Na}_2\text{O})}{(\text{SiO}_2 + \text{Al}_2\text{O}_3 + \text{TiO}_2)}$$

The ash is dry and has high fusion temperatures when the B/A is low. As the concentration of the fluxing elements increases, the ash becomes stickier and the ash fusion temperatures begin to decrease. There is a point above B/A=0.5 where the fusion temperatures reach a minimum, and further increases of the B/A above 0.75 only increase the amounts of fluxing or bonding material rather than meaningfully influencing the fusion temperatures.

The Fouling Index (FI) is most commonly applied to Eastern and Midwestern U.S. coals. It is useful in indicating the difference between Illinois Basin Coals.

The Fouling Index is expressed as:

FI = % Na ₂ O x	Base to Acid Ratio	
Rated:	0-0.2	Low
	0.2-0.5	Medium
	0.5-1.0	High
	< 1.0	Severe

More sodium = higher fouling.

The Western U.S. and other low rank coals can have considerable sodium percentages in the ash. A separate fouling factor is used for these coals. It is based solely on the sodium percentages in the coal ash.

Less than 3.0 %	Low/Medium
3.0-6.0%	High
Greater than 6.0%	Severe

Based on these measures and the values shown in Table A-1, it may be seen that coal from Spring Creek Mine would be expected to exhibit high fouling potential. Given that the sodium content of the Tongue River coal deposits is similar to Spring Creek, it too, is likely to be a high-fouling coal.

Uses of High-Sodium Coal

As stated, sodium content of Tongue River coal deposits is higher than for many other Powder River Basin mines, and high sodium can cause some difficulties in burning the coal. The concern is to what extent the effects of high-sodium coal limit its marketability. Experience shows that some high-sodium coals have been used in boilers that were not specifically designed for them. In 2011, Spring Creek Mine shipped approximately 19.1 million tons of coal (Cloud Peak Energy 2013).

Data collected by the U.S. Energy Information Administration on deliveries of coal to power plants show that this coal was purchased by more than 15 power plants in various parts of the United States. Some of these plants, such as the B C Cobb and Presque Isle plants, were designed for higher-quality bituminous coal. These plants may be using Spring Creek coal in a blend with higher-quality coals. Other plants using Spring Creek coal were designed for Powder River Basin or other lower-quality coal. These examples illustrate that the high sodium in coal is a handicap but not a barrier to the sale of this coal, domestically and internationally.

Table A-2 shows the deliveries of coal from Spring Creek Mine to various customers during 2012, which totaled 17.2 million tons. A total of 10.3 million tons were shipped to electric utilities in the United States. An additional 4.4 million tons were exported via various coal terminals in British Columbia, Canada (primarily Vancouver). Customers for the remaining 2.5 million tons were not specifically reported.

In addition to sales of higher-sodium coal in the U.S. market, for the last several years, coal from Spring Creek Mine has been exported to Asian customers. Cloud Peak, owner of Spring Creek Mine, reports exports of 4.4 million tons in 2012, most of which appears to be from Spring Creek Mine (Cloud Peak Energy 2013), which has a sodium content of 8.2%. Limited information is available on the specific buyers of this coal, but Korea is the largest. Buyers in Korea, China, Taiwan and others in the Asian market buy coal from many sources and may be blending coals of varying quality.

Buyers consider many trade-offs between coal quality and cost when purchasing Spring Creek coal or other higher-sodium coal when lower-sodium coal is available. Many factors affect these decisions, including the customer's boiler and air pollution control equipment, coal quality, and transportation costs.

Table A-2. Deliveries of Spring Creek Coal in 2012

Owner	Plant Name	Thousand Tons
Allete	Clay Boswell	1,625
Allete	Taconite	176
Alliant	Nelson Dewey	459
CMS Energy	B C Cobb	263
DTE Energy	Belle River	2,965
DTE Energy	St Clair	1,937
Pinnacle West Capital	Cholla	14
Salt River Project	Coronado	736
Trans Alta	Centralia	1,438
Weyerhaeuser	Longview	100
Wisconsin Energy Corp.	Presque Isle	586
Wyandotte DPS	Wyandotte	11
Subtotal Domestic Consumption		10,310
Exports		4,400
Other/Uncharacterized		2,500
Total		17,200
Sources: Cloud Peak Energy 2013; Ventyx 2013; Kokiino 2005.		

Conclusion

The high sodium content of coal from the Tongue River coal deposits is an undesirable characteristic. However, the use of similar coal by both U.S. and Asian consumers indicates that the quality of the Tongue River coal deposits is not likely to prevent its use. Some buyers clearly have a combination of boiler design, operational strategies, and coal blending that allows them to use coal with sodium content similar to the Tongue River coal deposits.

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