Conceptual Regulatory Impact Analysis Summary
Office of Surface Mining Stream Protection Rule

For the Office of Management and Budget Submission
By the United States Department of Interior Office of Surface Mining

December 23, 2010

-DRAFT: FOR REVIEW PURPOSES ONLY-
(Partial Revisions with Rest Completed for January 5, 2011 Report)

By Donald T. Iannone & Associates
Cleveland, Ohio

Table of Contents

I. Introduction and Purpose…….Page 3

II. Necessity of the Stream Protection Rule and the RIA…….Page 7

III. Baseline Conditions…….Page 10

IV. Analysis of Rule Alternatives…….....Page 17

V. Economic Benefits……...Page 26

VI. Transfers…….....Page 30

VII. Effects…….....Page 31

VIII. Summary…….....Page 40

IX. Appendix 1: EIA Coal Forecast Assumptions……Page 44

X. Appendix 2: Mining Engineering Task Force Assumptions and Methodology Used to Forecast Future Regional Production Shifts…...Page 52

XI. Appendix 3: Assumptions Used by Morgan Worldwide in the Proposed Rule (EIS Alternative 5) Cost Analysis…….....Page 61

I. Purpose and Background

Purpose

This report identifies the economic benefits, costs and other effects of the Office of Surface Mining's (OSM's) proposed Stream Protection Rule (SPR) on the U.S. coal mining industry and coal mining areas across the United States.

This summary contains the most salient information from the Conceptual Regulatory Impact Analysis (RIA) prepared on the proposed rule, providing the information required to support the review of the rule by the U.S. Office of Management and Budget (OMB).

Background

Work commenced on the "Conceptual" RIA in July 2010. Because of the proposed nature of the SPR, this RIA is conceptual in nature. A Final RIA will be prepared on the Final Rule once it exists in 2011.

The first full draft of the Conceptual RIA was delivered for review in mid-October 2010. Since then, the document has been under review. Based upon this review, significant revisions have been made to the Conceptual RIA document.

The full RIA document is comprised of a detailed main report, and twelve supporting appendices providing additional information about the RIA study methodology and data.

Study Approach

The Conceptual RIA utilized best available data and information to assess the economic impacts (costs and benefits) of the SPR. Ideally, an RIA monetizes, or defines in monetary terms, the impacts of a rule. Monetization of economic costs and benefits was accomplished where possible in this RIA, but in some cases this could not be done given data, time, and other limitations.

Where monetization of impacts was not possible, economic impacts were otherwise quantified to the extent possible. Where quantification was not possible, qualitative information about the economic impacts was included in the RIA.

The RIA analyzes three SPR alternatives:

- EIS Alternative 1 (Baseline): Pre-Rule Situation (Least Stringent and Least Costly)
- EIS Alternative 5: Proposed Rule
- EIS Alternative 2: Most Stringent and Most Costly Version of the Rule

The Baseline Situation includes the 2008 Excess Spoil Minimization/Stream Buffer Zone Rule, which was not implemented by state regulatory authorities. An analysis of the baseline economic

impact of the coal mining industry was conducted in the RIA. A distillation of the baseline analysis findings is included in Section III below.

Methodology and Data

Research Steps

The core method used in this study was Economic Impact Analysis, using the IMPLAN input/output model. IMPLAN is a credible, very well known and frequently used economic analysis model, which has been used to analyze the economic impacts of many proposed local, state, and national projects and policies. Several federal government agencies, including the U.S. Departments of Interior and Energy and the Environmental Protection Agency, have used the IMPLAN model to assess the economic impacts of their proposed policies. A more detailed description of the IMPLAN model is provided below.

Nine sequential steps were followed in the methodology:

1. **Data Acquisition.** Identify and acquire study data for all RIA scope elements. As the EIS has progressed, new data has been incorporated into the RIA, improving its ability to identify and quantify the proposed rule's economic costs and benefits.

2. **Interviews and Background Material Review.** Conduct industry and other stakeholder interviews to gain inputs of the study and identify resource materials that should be reviewed in preparation for the study. Several unsuccessful attempts were made in the early research phase of the RIA to acquire cost of compliance data from coal mining companies and their national industry association, the National Mining Association (NMA).

3. **SPR Analysis and Cost Element Identification.** Based upon industry, government, and academic interviews, a review of earlier coal-mining studies and reports, and a review of the academic literature on mining reclamation and transportation, workable assumptions were developed to use in the impact modeling runs. These assumptions have been refined as new data are developed through the EIS.

4. **Economic Model Preparation.** Acquire the input/output tables for the nation and all coal-producing states, and build the national, region (multi-state), state, and county models to be analyzed with the IMPLAN Economic Impact Analysis software.

5. **Economic Overview.** Prepare a summary of overall national economic trends relevant to the study.

6. **Industry Analysis.** Analyze all primary and secondary data regarding the coal-mining industry from various state and national sources.

7. **Coal-Mining State and County Analysis.** Analyze key economic trends in the 25 coal mining states and the seven case study counties included in the study.

8. **Economic Modeling.** Using the input data and scenarios created for the analysis, run the national, state, and county models to identify baseline and scenario impacts of the proposed rule.

9. **Small Mine/Business Impact Analysis.** Examine the potential impacts of the SPR on small coal mines/businesses in accordance with the Regulatory Impact Analysis (RFA) guidelines.

IMPLAN Model Description

This study employed the IMPLAN Model to make the primary economic forecasts. Input/output methodology allows the examination of forward (market) and backward (supplier) linkages that are present in an industry or local, state and national economy. The model measures the total annual economic activity that results from inter- and intra-industry transactions. The model breaks the economy into 440 sectors, with each sector representing an individual industry. It then uses a sectoring scheme developed by the IMPLAN Group (Minneapolis, Minnesota), which is closely related to the U.S. Bureau of Economic Analysis (BEA) Regional Economic Information System (REIS) model.

The IMPLAN model is a matrix that shows all the economic activity between the 440 sectors. The entries in the matrix are based on the dollar amount that each industry sells to (and purchases from) other industries in the economy. It measures the amount of final consumption by the residents of the identified geographic area, as well as how much each industry exports out of the area. The model uses data collected at the county level, which are obtained from the IMPLAN Group and BEA. County data are in turn aggregated, or "rolled up", to form service areas such as local areas, states, or larger geographic regions, such as the Midwest.

Input/output models estimate economic impacts by taking advantage of the relatively stable patterns in the flow of goods and services within the economy. The prediction of an industry's total economic impact can be made by examining the purchasing patterns of the individual sectors. BEA collects extensive data regarding these regional trade flows, and reports its findings annually.

Primary Data Sources

Data used in this study come from a variety of sources. The research team attempted to use the most recent reliable data sources. These sources include:

- Dun and Bradstreet firm data from the Selectory business database (2010)
- U.S. Bureau of Economic Analysis (BEA) (2008)
- U.S. Bureau of Labor Statistics (BLS), Census of Employment and Wages (2008)
- IMPLAN Structural Matrices and Data Files (2008)
- U.S. Energy Information Administration (EIA) Coal Sector Data (Various years)

Once the primary (direct) impact is identified, it is necessary to estimate the ultimate impact on the economy. This RIA's forecasting model used variables from various national datasets. To reduce potential confusion, definitions of the major variables are presented below.

Industry Output

Industry output represents the value of the industry's total production. Industry output can be thought of as the value of industry sales plus or minus inventory changes. Industry output is not a measure of an industry's income, and therefore cannot be directly compared to the Gross State Product (GSP) numbers reported by BEA. The value of industry output is typically higher than GSP. It is a more comprehensive measure, and therefore is a better measure of true economic impacts. The IMPLAN model estimates the industry output data, which are derived from the U.S. Census Bureau's Economic Census. The structural matrices are used to determine the industrial supply chains.

Employment

Employment is the total number of full-time wage and salary employees, plus the number of self-employed workers within a particular industry. Part-time workers' hours are aggregated into full-time equivalents (based upon a 2,080-hour work year), and reported with the full-time workers. Each year's activity is computed separately so that the employment effects are computed each year.

No single source of employment data is adequate for accurately estimating employment impacts. Because of nondisclosure rules, the employment figure reported by government agencies often underestimates true employment in a given county. In accordance with 13 U.S.C. § 9, no datum that would disclose the operations of an individual employer or put an individual employer at an unfair disadvantage is published.

As focus is narrowed to the county level, the number of firms representing an industry decreases. It is common for a single business establishment to be the sole operator in that industry in a particular county. If this is the case, the employment numbers are not disclosed and the employment in that region is understated. A region's employment can be reconstructed by combining data from various sources.

Nondisclosure rules require that the individual reporting agency not reveal confidential information. However, other government agencies may report the missing data in another form. For example, the U.S. Department of Labor (DOL) collects labor data as part of the Unemployment Insurance ES-202 program. These data are for "covered employees" of the Unemployment Insurance Program. Workers not "covered," such as self-employed workers, would not be included in the data. However, "not covered" workers would be included in the employment figures captured by the U.S. Census Bureau's County Business Patterns.

By carefully combining the employment figures reported in the ES-202 dataset, County Business Patterns, the REIS data, and the IRS Quarterly Payroll File (Federal Insurance Contributions Act), a fairly comprehensive employment figure can be reconstructed. The raw data are then

"sectored" into the appropriate North American Industry Classification Codes (NAICSs) and, in turn, combined into the necessary industry sectors and IMPLAN matrices.

All impact numbers generated by the IMPLAN model are one-point-in-time in nature and not cumulative. For this RIA, these numbers were spread over an assumed 12-year implementation period for the rule.

II. Necessity of the Stream Protection Rule and the RIA

Rule Necessity

The Surface Mining Control and Reclamation Act of 1977 (SMCRA) aims to balance the need to protect the environment from the adverse effects of surface coal mining with the nation's need for coal as an essential energy source. The law ensures that coal mining operations are conducted in an environmentally responsible manner, and that mined land is adequately reclaimed during and following the mining process.

Most coal mining states now have the primary responsibility to regulate surface coal mining on lands within their jurisdiction, with OSM performing an oversight role. OSM also partners with states and Indian tribes to regulate mining on federal lands and Indian lands, and to support states' regulatory programs with grants and technical assistance.

Because of significant damage by coal mining activities to streams and other environmental resources, the SPR is needed to reduce and prevent future environmental damage and degradation.

In April 2010, OSM published in the Federal Register a Notice of Intent to produce an Environmental Impact Statement (EIS) for the proposed rule. The notice includes a list of concepts that are under consideration for the proposed SPR. Those concepts include provisions for coal mining companies that elect to mine through or bury streams to gather more specific baseline data regarding a proposed mine site's hydrology, geology, and aquatic biology; establishing a definition of the term "material damage to the hydrologic balance" of watersheds outside the permit area; and developing more effective requirements for mine operators seeking a variance from the requirement that mined areas be reclaimed to their approximate original contour.

The concepts in the proposed SPR aim to offer a more systematic and comprehensive approach to protecting streams and the surrounding environment from the adverse effects of coal mining. The proposed SPR contains 13 elements. The general intent of each of these elements is briefly described below:

- **Baseline Data and Analysis.** Proposes adding more extensive and specific permit application requirements concerning baseline data on hydrology, geology, and aquatic biology.

- **Material Damage Definition.** Proposes a definition for the term "material damage to the hydrologic balance outside the permit area." Under the Surface Mining Control and Reclamation Act (SMCRA), the regulatory authority may not approve a permit unless the proposed operation has been designed to prevent material damage to the hydrologic balance outside the permit area; however, this term is not defined in OSM regulations.

- **Activities in or Near Streams.** Addresses the circumstances under which an applicant could engage in coal-mining or mining-related activities in or near a stream.

- **Mining Through Streams.** Addresses the conditions under which mining through a streambed could be allowed.

- **Monitoring During Mining and Reclamation.** Describes the types of water and biological sampling, locations of water sampling, and duration of monitoring after issuance of the mining permit.

- **Surface Configuration and Fills.** Addresses performance standards for the final configuration of fills, and the generation and disposal of excess spoil and coal mine waste material.

- **Approximate Original Contour (AOC) Exceptions.** Addresses limits to exceptions from AOC restoration requirements.

- **Revegetation and Topsoil Management.** Addresses the restoration of the vegetation and soils following mining.

- **Permit Coordination.** Addresses coordination among regulatory authorities at the state and federal levels.

- **Financial Assurance for Long-term Discharges of Pollutants.** Addresses performance bond and financial assurance requirements for long-term discharges associated with mining.

- **Stream Definition.** Addresses the definitions of perennial, intermittent, and ephemeral streams.

- **Performance Bonds and Release.** Addresses bonding requirements and the release of bonds, to ensure that funds are available to states if needed to reclaim and restore mined lands if a mining company fails to properly reclaim lands.

- **Fish and Wildlife Protection and Enhancement.** Addresses protection and enhancement of these resources.

Need for the RIA

OMB requires that an RIA be prepared and submitted by all federal agencies proposing new regulations that are expected to have a significant economic impact. An annual economic impact of at least $100 million is the threshold for defining a significant economic impact.[1] The proposed rule is expected to have an annual economic impact of more than $100 million per year, and therefore an RIA is required.

As a requirement of OSM's rule-making process, the RIA is intended to improve understanding of the potential economic impacts (costs and benefits) of the proposed rule on the coal mining industry and coal-producing geographic areas across the United States. Both are major stakeholders that would be affected by the content of the proposed rule.

OSM requested this stakeholder focus in recognition of the potentially significant economic impacts of the proposed rule on these two stakeholders. Study interviews and the study's analysis indicate that some of the provisions of the proposed rule could have significant cost implications for coal mining companies. To the extent possible, these impacts are estimated in quantitative terms. Other impacts are described in qualitative terms only because they cannot be measured in a quantitative way at this time.

An April 1, 2010, U.S. Environmental Protection Agency (USEPA) Guidance Memorandum on improving U.S. EPA's review of Appalachian surface-mining operations lends support to OSM's new SPR nationwide. The memorandum states:

> *"The environmental legacy of mining operations in the Appalachian region is far-reaching. Recent studies, as well as the experiences of Appalachian coalfield communities, point to new environmental and health challenges from surface coal mining that we were largely unaware of even ten years ago. Since 1992, nearly 2,000 miles of Appalachian streams have been filled at a rate of 120 miles per year by surface mining practices. A recent EPA study found that nine out of every 10 streams downstream of surface mining operations exhibit significant impacts to aquatic life. Another federal study found elevated levels of highly toxic and bioaccumulative selenium in streams downstream of valley fills. These impairments are linked to contamination of surface water supplies and resulting health concerns, as well as widespread impacts to stream life in downstream rivers and streams."*

In summary, this RIA is needed for two major reasons:

- Provide an improved overall economic basis for the regulatory policy decisions made during this rule-making process.

[1] U.S Office of Management and Budget, Circular A-94.

- Identify any major economic issues raised by the proposed rule that may have significant consequences for the coal mining industry and coal-producing areas.

III. Baseline Conditions (Least Stringent Alternative/Least Negative Economic Impact)

Introduction

According to Regulatory Impact Analysis (RIA) guidance from the U.S. Office of Management and Budget (OMB), the starting point for an RIA is a characterization of the baseline conditions relative to the rulemaking process. This is the economic baseline against which the other rule alternatives are compared. It is also considered to be the Least Stringent Alternative, which also is expected to have the least economic impact on the coal mining industry and coal-producing areas.

Current Federal Regulatory Environment

All federal regulations have economic costs and benefits, but definitive measures of these costs and benefits are often not possible.[2] This is believed to be the case with this respect to this proposed rule.

The baseline situation in this RIA recognizes the current federal regulatory environment for coal mining, although no comprehensive data are available to assess either the costs of current coal mining practices to society or the costs to the coal mining industry to comply with current regulations.

According to the National Mining Association (NMA), more than three dozen federal environmental laws and regulations cover all aspects of mining. The following list includes some of those major laws.

In addition, each state has laws and regulations that mining companies must follow.[3]

- Surface Mining Control and Reclamation Act - regulates coal mining operations and reclamation.
- National Environmental Policy Act - requires an interdisciplinary approach to environmental decision-making.
- Federal Land Policy and Management Act - prevents undue and unnecessary degradation of federal lands.
- Clean Air Act - sets air quality standards.
- Federal Water Pollution Control Act (Clean Water Act) - directs standards for surface water quality and controlling discharges to surface water.

[2] U.S. Office of Management and Budget, 2010 Report to Congress on the Benefits and Costs of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, Washington DC.
[3] National Mining Association website: www.nma.org. Accessed on December 17, 2010.

- Safe Drinking Water Act - directs standards for quality of drinking water supplied to the public (states are primary authorities) and regulating underground injection operations.
- Solid Waste Disposal Act - regulates generation, storage and disposal of hazardous waste and manages solid, non-hazardous waste (states).
- Comprehensive Environmental Response, Compensation and Liability Act -requires reporting of hazardous substance releases and inventory of chemicals handled.
- Toxic Substance Control Act - requires regulation of chemicals that present risk to health or environment.
- Endangered Species Act - lists threatened plants and animals; protection plans mandated.
- Migratory Bird Treaty Act - protects nearly all bird species.

Other laws that impact mining include the:

- Rivers and Harbors Act,
- Federal Mining Law,
- National Historic Preservation Act,
- Law Authorizing Treasury's Bureau of Alcohol, Tobacco and Firearms to Regulate Sale, Transport and Storage of Explosives, and
- Federal Mine Safety and Health Act.

While it may be desirable to know the "baseline" economic costs and benefits of current coal-related federal regulations to society and the coal industry, it is not possible to estimate these impacts in the context of this RIA.

While OMB tracks some of the costs of regulatory compliance, as reported in individual regulatory impact analyses, no analysis of the overall cost of all of these regulations to the coal mining industry exists. To the best of our knowledge, no industry source, including the National Mining Association (NMA), has any estimate of the compliance cost to coal mining businesses created by these regulations.

Broader regulatory cost studies (not related specifically to the coal mining industry) attempt to produce estimates of the cost of all federal regulations to society. A very rough extrapolation from an evaluation of the entire federal regulatory enterprise (all federal agencies) by the Competitive Enterprise Institute (CEI) estimates that annual regulatory compliance costs hit $1.187 trillion in 2009.[4] Environmental regulations are estimated to account for $236 billion of this total, or nearly 20% of the total. The analysis also estimates that overall federal regulatory costs:

- Are equivalent to 63 percent of all 2007 corporate pretax profits of $1.89 trillion.
- Dwarf corporate income taxes of $147 billion.
- Exceed estimated 2009 individual income taxes of $953 billion by 25 percent.

[4] Crews, Clyde Wayne, Ten Thousand Commandments: An Annual Snapshot of the Federal Regulatory State, 2010 Edition, Competitive Enterprise Institute, Washington, DC.

- Absorb 8.3 percent of the U.S. gross domestic product (GDP), estimated at $14.253 trillion in 2009.

In its 2010 report to Congress, OMB found that:[5]

- The estimated annual benefits of major Federal regulations reviewed by OMB from October 1, 1999, to September 30, 2009, for which agencies estimated and monetized both benefits and costs, are in the aggregate between $128 billion and $616 billion, while the estimated annual costs are in the aggregate between $43 billion and $55 billion. These ranges reflect uncertainty in the benefits and costs of each rule at the time that it was evaluated.

- Some rules are estimated to produce far higher net benefits than others. Moreover, there is substantial variation across agencies in the total net benefits produced by rules. For example, the air pollution rules from the Environmental Protection Agency (EPA) produced 60 to 87 percent of the benefits and 58 to 64 percent of the costs. Most rules have net benefits, but some rules have net costs.

Key Baseline Assumptions

The following assumptions were employed in analyzing the baseline situation:

1. At the request of OSM, the analysis in the EIS and RIA was restricted to assessing the proposed rule's economic impacts on the coal mining industry and areas. This study scope did not include the analysis of other industry or broader economic effects, such as those on the electricity industry, which uses almost 94% of all coal produced in the United States. For this reason, it was not possible in this RIA to assess the economic effects of possible higher coal prices caused by this rule to coal users.

2. Because of coal's availability and affordability, coal is a valuable energy resource to society and the economy. To the extent that coal continues to possess these two major advantages, its importance will remain into the future.

3. The coal mining industry is currently a regulated industry, and coal mining companies have worked to reduce their negative environmental impacts over the past several years, yet much work remains in this area in the future.[6]

4. The baseline uses 2008 data for analysis purposes to reflect the current regulatory environment, including the 2008 Stream Buffer Zone (SBZ) rule and other existing regulations applied to the coal mining industry.

[5] U.S. Office of Management and Budget, 2010 Report to Congress on the Benefits and Costs of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities, Washington DC.
[6] Both the Office of Surface Mining (OSM) and the National Mining Association (NMA) in their annual reports and other publications suggest environmental progress is being made by the coal mining industry, but neither offers quantitative data to measure this progress.

5. 2008 is an economic recession year, and therefore the economy was amidst a major downturn. This economic downturn is assumed to have reduced the demand for coal, which was evidenced in 2009 with lower overall coal demand numbers.[7]

6. Until the economy recovers to a more significant degree, both the coal mining industry and federal and state regulatory authorities may struggle to meet the financial requirements associated with implementation and compliance with the proposed rule.

7. No major changes are foreseen in regional coal production and mining methods (surface versus underground) under EIS Alternative 1 over the next 12 years.

A coal mining engineering task force, comprised of Morgan Worldwide, ECSI Engineering Services, MACTEC, and OSM was assembled to develop a "consensus" forecast on potential regional coal production and mining method shifts over the next 12 years. Table 1 identifies the baseline (existing) production levels in the 7 coal-producing regions in the future for the Baseline Situation (EIS Alternative 1).

Table 1: Current Coal Mining Levels Related to Baseline Situation (EIS Alternative 1)

	Production (Million Short Tons)		
Region	**Underground**	**Surface**	**Total**
Northern Rocky Mountains and Great Plains	3.67	538.39	542.06
Appalachian Basin	220.23	149.38	369.61
Illinois Basin	64.61	34.27	98.88
Colorado Plateau	55.78	34.28	90.06
Gulf Region	12.28	54.10	66.38
Other Western Interior	0.44	1.50	1.94
Northwest	-	1.48	1.48
Total	357.01	813.39	1,170.40

Source: Mining Engineering Coal Production Forecast Task Force, October-November 2010 Analysis

Analysis

As stated earlier, the baseline includes the 2008 Excess Spoil Minimization/Stream Buffer Zone Rule and all other federal regulations applied to the coal mining industry. The EIS and RIA for the 2008 rule concluded the rule would have no significant economic impact.

Table 2 below depicts the baseline economic impact of the coal mining industry on the U.S. economy as a whole. It shows a $32.1 billion direct impact on the national economy. Coal mining is responsible for another $23.2 billion impact in indirect impacts (business-to-business supply chain impacts), and another $26.3 billion in employee spending (induced impacts), bringing the total impact of coal mining on the national economy to more than $81.5 billion.

[7] U.S. Energy Information Administration (EIA), 2010 Energy Outlook Report.

Table 2 also shows the economic sectors that are most closely linked to coal mining, and the impacts in terms of business-to-business and employee spending. The top four sectors are: 1) support activities for mining; 2) wholesale trade businesses; 3) management of companies and enterprises; and 4) transport by rail. These sectors constitute nearly one-fourth of the supply chain expenditures.

Table 2: 2008 Baseline National Economic Output Impact of the Coal Mining Industry

Sector	Description	Direct ($)	Indirect ($)	Induced ($)	Total ($)
	Totals	**32,084,721,664**	**23,162,847,232**	**26,336,821,248**	**81,584,193,536**
21	Mining coal	32,084,721,664	2,029,731,840	29,863,232	34,144,256,000
30	Support activities for other mining	0.0	2,195,267,584	3,189,744	2,198,454,272
319	Wholesale trade businesses	0.0	1,000,024,064	1,148,633,088	2,148,655,104
360	Real estate establishments	0.0	383,846,400	1,427,955,712	1,811,800,064
356	Securities, commodity contracts, investments, and related activities	0.0	763,830,272	634,296,320	1,398,128,640
381	Management of companies and enterprises	0.0	1,002,776,576	356,299,776	1,359,077,376
115	Petroleum refineries	0.0	757,313,536	532,632,576	1,289,945,088
31	Electric power generation, transmission, and distribution	0.0	677,767,168	422,944,768	1,100,709,888
354	Monetary authorities and depository credit intermediation activities	0.0	483,776,512	610,693,120	1,094,467,584
333	Transport by rail	0.0	1,032,026,112	52,721,152	1,084,743,680
413	Food services and drinking places	0.0	105,977,856	854,038,528	960,016,384
369	Architectural, engineering, and related services	0.0	831,934,464	96,962,560	928,897,024
351	Telecommunications	0.0	298,811,392	610,592,768	909,404,160
357	Insurance carriers	0.0	121,138,432	764,225,536	885,364,736
394	Offices of physicians, dentists, and other health practitioners	0.0	2,562	863,358,976	863,361,024
335	Transport by truck	0.0	592,918,528	240,849,920	833,767,424
397	Private hospitals	0.0	3,330	827,920,384	827,922,432
205	Construction machinery manufacturing	0.0	817,332,224	1,279,540	818,612,224
20	Extraction of oil and natural gas	0.0	463,098,880	292,632,576	755,732,480

Source: IMPLAN model run, August 2010

Table 3 below shows the results of the baseline analysis of the economic output impact of the coal mining industry in each of the coal-producing states.

Across the coal-producing states, the coal mining industry has a total economic output value of $48.7 billion, with the largest economic output occurring in West Virginia ($9.7 billion), Kentucky ($8.4 billion), Pennsylvania ($6.1 billion), Virginia ($3.8 billion), and Wyoming ($3.6 billion).

The totals shown reflect the sum of impacts across the coal-producing states, and are not the same as the national impacts shown in Table 2 above. The coal-mining industry's total baseline economic output impact on the national economy is estimated at $81.5 billion, and the total economic output impact across the coal-producing states is $48.7 billion, which is approximately 60 percent of the national impact. The other 40 percent of this economic output impact occurs in the non-coal-producing states.

Table 3: Baseline State Economic Output Impact Analysis (Based on 2008 Data)

States	Direct	Indirect	Induced	Total
Alabama	$2,179,324,160	$501,268,437	$554,047,439	$3,234,640,101
Alaska	$10,734,416	$2,529,933	$2,525,246	$15,789,595
Arizona	$76,019,976	$19,338,410	$25,462,825	$120,821,210
Arkansas	$18,565,028	$3,598,628	$3,966,141	$26,129,796
Colorado	$1,136,597,632	$292,372,699	$403,660,565	$1,832,630,893
Illinois	$1,164,327,552	$417,383,281	$441,648,921	$2,023,359,694
Indiana	$1,639,472,768	$298,353,406	$439,638,097	$2,377,464,227
Kansas	$41,053,352	$7,577,350	$10,352,527	$58,983,225
Kentucky	$5,546,564,096	$1,554,182,780	$1,309,399,370	$8,410,146,403
Louisiana	$88,399,088	$21,541,460	$23,834,350	$133,774,902
Maryland	$54,881,188	$14,517,917	$15,018,628	$84,417,733
Mississippi	$36,412,316	$6,204,251	$8,276,416	$50,892,984
Missouri	$263,985,776	$64,553,798	$81,072,616	$409,612,186
Montana	$302,833,216	$67,314,615	$72,445,454	$442,593,266
New Mexico	$416,587,264	$69,543,821	$88,032,081	$574,163,188
North Dakota	$393,881,472	$70,897,559	$74,066,922	$538,845,950
Ohio	$813,621,248	$251,214,848	$258,988,544	$1,323,823,104
Oklahoma	$66,184,240	$15,324,907	$16,740,062	$98,249,207
Pennsylvania	$3,492,621,056	$1,250,007,809	$1,315,121,124	$6,057,750,026
Tennessee	$69,778,640	$22,318,727	$20,746,490	$112,843,855
Texas	$1,362,782,336	$402,430,822	$492,708,229	$2,257,921,328
Utah	$741,357,120	$210,667,504	$235,922,348	$1,187,946,971
Virginia	$2,452,940,288	$627,762,584	$736,282,657	$3,816,985,705
Washington	$23,676,292	$7,402,652	$8,313,728	$39,392,671
West Virginia	$7,060,627,968	$1,471,882,625	$1,259,405,361	$9,791,916,251
Wyoming	$2,756,616,192	$455,333,145	$434,596,660	$3,646,546,111
Totals	$32,209,844,680	$8,125,523,968	$8,332,272,801	$48,667,640,582

Source: IMPLAN model run, August 2010

Table 4 below shows the amount and distribution of the baseline economic output by coal-producing region. The Appalachian Basin has a current 68 percent share of the total. Each of

the other coal-producing regions has less than a 10 percent share of the coal mining industry's current economic output impact.

Table 4: Baseline Economic Output by Coal-Producing Region

Region	Baseline Economic Output	% Total
Appalachian Basin	$32,832,523,177	67.77
Colorado Plateau	$3,715,562,262	7.67
Gulf Region	$2,442,589,213	5.04
Illinois Basin	$4,400,823,921	9.08
Northern Rocky Mountains and Great Plains	$4,627,985,327	9.55
Northwest	$15,789,595	0.03
Other Western Interior	$409,612,186	0.85
Total-All Regions	$48,444,885,682	100.00

Source: IMPLAN model run, September 2010

As shown in Table 5 below, across the coal-producing states, the coal mining industry had a total baseline employment impact of 182,785 jobs, with the largest employment impact occurring in West Virginia (37,014), Kentucky (34,185), Pennsylvania (23,238), Virginia (12,384), and Wyoming (12,056).

Table 5: Baseline State Employment Impact Analysis (Based on 2008 Data)

State	Direct	Indirect	Induced	Total
Alabama	4,154	2,449	4,903	11,506
Alaska	24	10	19	54
Arizona	182	103	203	488
Arkansas	51	21	37	109
Colorado	2,304	1,397	3,001	6,702
Illinois	3,124	1,695	3,082	7,900
Indiana	2,795	1,567	3,888	8,250
Kansas	84	40	93	216
Kentucky	15,015	7,464	11,706	34,185
Louisiana	144	99	204	448
Maryland	153	65	111	329
Mississippi	80	36	80	196
Missouri	437	320	680	1,437
Montana	838	390	684	1,912
New Mexico	1,092	409	818	2,319
North Dakota	903	374	703	1,981
Ohio	2,253	1,226	2,184	5,663
Oklahoma	145	76	148	369
Pennsylvania	8,317	5,144	9,777	23,238
Tennessee	273	110	165	549
Texas	2,681	1,709	3,578	7,968
Utah	2,077	1,179	2,110	5,366

State	Direct	Indirect	Induced	Total
Virginia	3,961	2,719	5,703	12,384
Washington	55	33	58	146
West Virginia	17,915	6,972	12,126	37,014
Wyoming	6,074	2,161	3,821	12,056
Totals	75,131	37,768	69,882	182,785

Source: IMPLAN model run, August 2010

Conclusion

The Baseline Situation, or Least Stringent and Least Costly Alternative is found to have little to no impact on the coal mining industry's current $81.6 billion economic output impact and its 182,785 employment impact nationally.

IV. Analysis of the Proposed Rule and Most Stringent Rule Alternatives

The Proposed Rule (EIS Alternative 5) and the Most Stringent Rule Alternative (EIS Alternative 2) were analyzed. First, it is important to consider the overall coal production and consumption trends forming the foundation for the RIA scenario analysis. These trends are assumed to set the stage for the coal mining industry's future production and consumption trends.

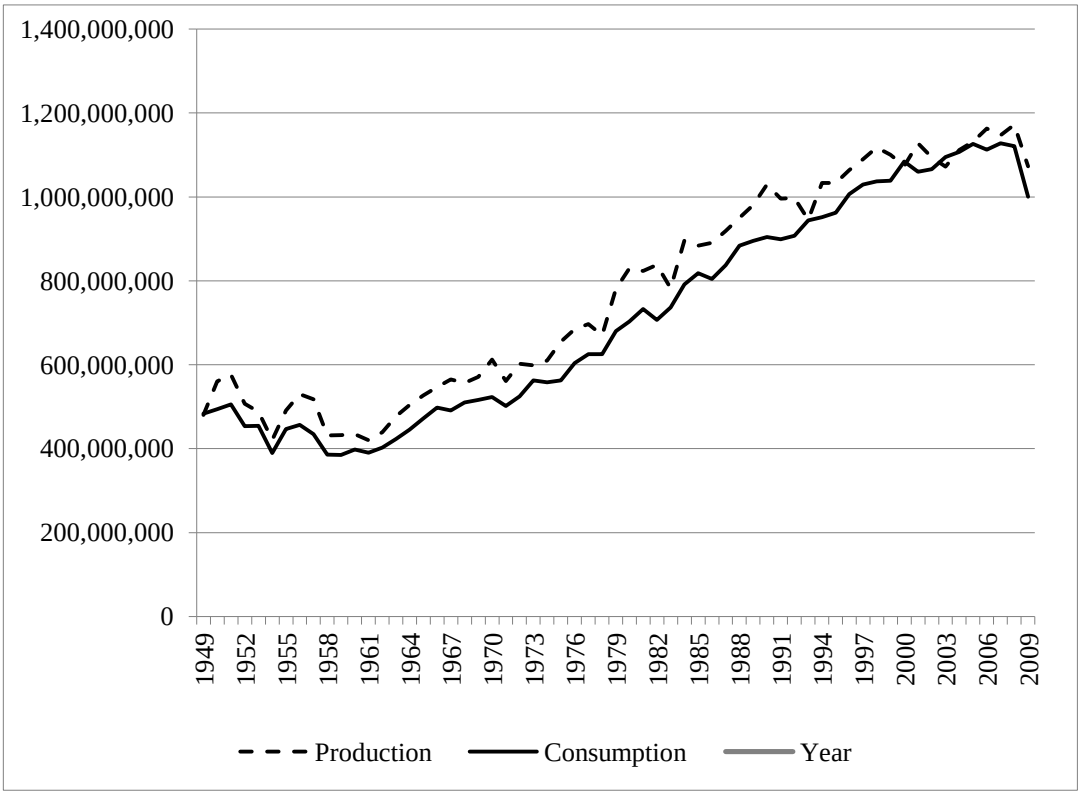
Long Term Historic National Coal Production and Consumption Trends

An important trend to bear in mind related to the two analyzed scenarios is how the proposed SPR could impact coal mining production and consumption levels. Figure 1 below shows these trends since 1949, or over the past 60 years.

The overall picture is one of a fairly consistent relationship between coal production and consumption. From a macro analysis standpoint, SMCRA, which was adopted in 1977, has had no observable negative impact on the overall national coal supply and demand numbers. There have been significant regional shifts in coal production, which are discussed below.

If this relationship continues in the future, coupled with a flat/slow-growth outlook for coal in the future, it is possible that the proposed SPR may have little impact on the coal mining industry itself, especially if the industry is capable of passing along the additional costs created by the SPR to its customers. Historically, this has been the case, and major coal users (electric power generators and steel producers) have been able to pass these costs on to their customers.

Figure 1: Long-Term Production and Consumption Trends in U.S. Coal Industry



Source: US Energy Information Administration (EIA), Annual Coal Outlook Report, 2010.

The scope of the Conceptual RIA did not include an analysis of the economic impact of SPR compliance costs on the electric power sector and other major coal using industries and final business and household consumers. Once a final rule exists, the final RIA should include this analysis to understand the overall effects of the rule on these economic sectors. Table 6 below identifies major trends in coal demand over the past five years (2005-2009).

Total coal consumption dropped by more than 11 percent during the 2005-2009 period, with the largest decline occurring in 2009, which was triggered by the economic recession that depressed demand by electric power generators and other markets, as shown in Table 6.

Table 6: U.S. Coal Consumption by Major Sector

Market	2005	2006	2007	2008	2009	2005-2009 % Change
Consumption by Sector						
Electric Power	1,037.50	1,026.60	1,045.10	1,040.60	936.5	-9.73
Coke Plants	23.4	23	22.7	22.1	15.3	-34.62
Other Industrial Plants	60.3	59.5	56.6	54.4	45.4	-24.71
Residential/Commercial Users	4.7	3.2	3.5	3.5	3.2	-31.91

Total	1,126.00	1,112.30	1,128.00	1,120.50	1,000.40	-11.15

Source: USEIA. 2009. U.S. coal supply and demand review, 2009.

The most significant observation regarding the coal market is its continued dominance by electric power generation, which has historically accounted for 90 to 94 percent of total coal demand.

Regional Coal Production Shifts, 2005-2009

U.S. Energy Information Administration (EIA) data in Table 7 below indicate a steady shift away from Eastern coal supplies and growing reliance on Western supply sources. This shift has been under way for some time, and is motivated by many factors, including the cleaner quality of Western coal and the faster growth of Western coal markets than those in the East.

U.S. coal production decreased considerably in 2009, dropping by 8.5 percent to 1,072.8 million short tons, 99.1 million short tons less than the 2008 production total. The decline in coal production in 2009 was the largest percent decline since 1958 (when production declined by 16.7 percent) and the largest tonnage decline since 1949 (when production declined by 176.1 million short tons).

Although total U.S. coal production was lower in 2009, one (Interior Region) of the three coal-producing regions had a slight increase in coal production, while the other two had large declines. Aside from refuse production, the Appalachian and Western Regions had decreases in their respective 2009 production levels of 13.0 percent and 7.7 percent, while the Interior Region remained essentially unchanged. The decrease in the Appalachian Region production was 50.9 million short tons, while the decrease in Western Region production in 2009 was 49.1 million short tons. Coal production in the Interior Region increased, but by only 216 thousand short tons.

Table 7: Coal Production in the United States

Area	**2005**	**2006**	**2007**	**2008**	**2009**	**2005-2009 % Change**
Production by Region						
Appalachia	396.7	391.2	377.8	390.2	339.3	-14.47
Northern Appalachia	140	136.2	132.1	135.6	126.5	-9.64
Central Appalachia	235.3	236.1	226.2	234	194	-17.55
Southern Appalachia	21.3	18.8	19.3	20.6	18.7	-12.21
Interior	149.2	151.4	146.7	146.6	146.8	-1.61
Western	585	619.4	621	633.6	584.5	-0.09
Refuse Recovery	0.7	0.8	1.2	1.4	2.1	200.00
Total	1,131.50	1,162.80	1,146.60	1,171.80	1,072.80	-5.19

Source: USEIA, U.S. coal supply and demand review, 2009.

The mining engineering production task force prepared forecasts for each of the EIS Alternatives. The task force's forecasts for EIS Alternative 5 (Proposed Preferred Rule) and EIS Alternative 2 (Most Stringent and Costly Rule) are discussed below in conjunction with the RIA's analysis of each of these rule alternatives.

Surface and Underground Mining Trends

Figure 2 below shows coal production trends by major mining method since 1949. Since the early 1970s, surface mining has grown in importance as the economics of the coal mining industry shifted, and more labor-intensive underground mining took a lesser priority to more productive surface mining methods. The enactment of the SMCRA and creation of OSM in 1977 appears to have no negative impact on surface mining production levels. To the contrary, surface mining has steadily grown over the past 33 years.

Figure 2: Long-Term U.S. Trend in Surface and Underground Mining

Key Assumptions Used in Analyzing EIS Alternatives 5 (Proposed Rule) and 2 (Most Stringent Case)

Three sets of working assumptions have been recognized in analyzing the economic impacts of the proposed rule (EIS Alternative 5) and the most stringent version of the rule (EIS Alternative 2). The discussions of assumptions are quite lengthy, and therefore they have been placed appendices to this summary report. Appendix 1 describes the assumptions used in the U.S. EIA's

most recent Coal Forecast under its 2010 Energy Outlook. Appendix 2 contains the assumptions and methodology used by the mining engineering task force, which has developed a preliminary forecast of regional coal production shifts in the future. Finally, Appendix 3 defines the assumptions and methodology used by Morgan Worldwide in preparing cost estimates for the proposed rule (EIS Alternative 5).

Much of the RIA in its conceptual form relates to the estimates economic "costs" of the rule in its various forms. With the completion of the Draft EIS and other data become available, the RIA will be revised to include more information about economic "benefits" of the rule. Additional illustrative information about the rule's potential economic benefits will be added to this summary document in preparation of our January 5, 2011 submission to OSM.

EIS Alternative 5 (Proposed Rule Analysis)

EIS Alternative 5 is the proposed rule because it offers the most balanced approach to protecting the environment and ensuring the nation's demands for coal as a fuel source are effectively met.

A major underlying assumption giving shape to the RIA analysis of Alternative 5 is that the proposed rule will cause some reductions in coal production and consumption and some shifts in regional mining locations and mining methods. These shifts are described below in Table 8.

In Alternative 5, rule-related compliance cost estimates were calculated on a per-coal-ton basis for each of the seven coal-producing regions. These estimates considered all 13 elements of the proposed SPR. The per-ton cost estimates were created with a cost estimation methodology developed by Morgan Worldwide Consultants, Inc. See Appendix 3 for the detailed assumptions and methodology used in this analysis.

The compliance cost estimates for each region were applied to the annual coal production data for each of the seven coal-producing regions. The resulting regional data were then entered into the IMPLAN model as reductions in coal-mining industry output. The model then calculated the estimated reductions in coal industry economic output and employment at the national level and for each region based upon the cost estimates.

The mining engineering task force forecasted production and mining method shifts under EIS Alternative 5 are described in Table 8 below. The central concern in these shifts is the loss of production to the coal regions impacted by the proposed preferred rule.

Table 8: Forecasted Lost Coal Production Under EIS Alternative 5, 2010-2022

	Lost Production (Million Short Tons)			Lost Production (%)		
Region	**Underground**	**Surface**	**Total**	**Underground**	**Surface**	**Total**
No Rocky Mtns/Great Plains	-	-	-	0.00%	0.00%	0.00%
Appalachian Basin	-0.37	-47.88	-48.25	-0.17%	-32.05%	-13.05%
Illinois Basin	-	-7.27	-7.27	0.00%	-21.20%	-7.35%

Colorado Plateau	-0.41	-1.28	-1.69	-0.74%	-3.74%	-1.88%
Gulf Region	0.00	-12.10	-12.10	-0.02%	-22.36%	-18.23%
Other Western Interior	- 0.44	-1.50	-1.94	100.00%	100.00%	100.00%
Northwest	-	- 0.48	-0.48	0.00%	-32.30%	-32.30%
Total	- 1.22	-70.50	-71.72	-0.34%	-8.67%	-6.13%

Source: Mining Engineering Coal Production Forecast Task Force, October-November 2010 Analysis

The forecast in Table 8 above points to an overall (across all regions) production loss of 71.7 million tons, with the lion's share of that loss occurring in surface mining (70.5 million tons). This is a 6.13% over loss of production due to rule's requirements under Alternative 5.

The cost of these losses was calculated in two ways. In the first, the compliance cost estimates were modeled in IMPLAN using early cost estimates produced by Morgan Worldwide. The results were than compared to the Baseline IMPLAN modeling results. These results are summarized in Table 10 below. The cost data for Alternative 5 is contained in Table 9 below. Based upon an analysis of the cost components of Alternative 5, these estimates were prepared for both underground and surface mining in each of the 7 regions. A weighted cost was calculated for these costs for use in the IMPLAN model. Both economic output and employment impact were estimated using the IMPLAN model.

Table 9: Per Ton Compliance Cost Estimates for EIS Alternative 5

Coal-Producing Region	Underground Cost per Ton	Surface Cost per Ton	% Underground Mining	Weighted Cost
Northern Rocky Mountains/Great Plains	$0.253	$0.194	0.68%	$0.195
Appalachian Basin	$0.758	$7.359	59.59%	$3.426
Illinois Basin	$0.494	$2.934	65.34%	$1.340
Colorado Plateau	$0.186	$1.049	61.93%	$0.515
Gulf Region	$0.122	$2.813	18.50%	$2.315
Other Western Interior	$0.218	$7.480	22.73%	$5.829
Northwest	$0.000	$2.407	0.00%	$2.407

Source: Morgan Worldwide, October 2010

The numbers in Table 9 indicate that the greatest cost burden on a per ton basis for complying with the rule under Alternative 5 are likely to fall in Other Western Interior and Appalachian regions.

Table 10: Coal Mining Economic Output Modeling of Compliance Costs Associated with EIS Alternative 5, 2010-2022

Region	Baseline Economic Output	Overall Change Caused by EIS Alternative 5	% Decrease Under EIS Alternative 5	Average Annual Reduction in Economic Output
Appalachian Basin	$32,832,523,177	-$1,114,815,653	-3.40	-$92,901,304
Colorado Plateau	$3,715,562,262	-$31,900,996	-0.86	-$2,658,416
Gulf	$2,442,589,213	-$72,496,342	-2.97	-$6,041,362
Illinois Basin	$4,400,823,921	-$65,892,542	-1.50	-$5,491,045
N Rocky Mtn & Great Plains	$4,627,985,327	-$62,161,400	-1.34	-$5,180,117
Northwest	$15,789,595	-$2,195,474	-13.90	-$182,956
Other Western Interior	$409,612,186	-$7,666,546	-1.87	-$638,879
Total - All Regions	$48,444,885,682	-$1,357,128,953	-2.80	-$113,094,079

Source: IMPLAN model run, October 2010

Across all 7 coal-producing regions, the total loss of economic output impact is estimated at $1.357 billion over the 12 years, with an average annual loss of $113 million. The Appalachian Basin is expected to see the biggest part of this loss ($1.114 billion over 12 years), with an average annual loss of almost $93 million. The smallest losses are expected in the Northwest and Other Western Interior regions.

Table 11: Coal Mining Employment Modeling of Compliance Costs Associated with EIS Alternative 5, 2010-2022

Region	Baseline Employment	Employment Reduction Caused by EIS Alternative 5	% Employment Change Caused by EIS Alternative 5	Average Annual Employment Reduction
Appalachian Basin	124,867	-4,679	-3.7	-390
Colorado Plateau	14,874	-136	-0.9	-11
Northern Rocky Mountains and Great Plains	15,949	-246	-1.5	-21
Illinois Basin	16,150	-256	-1.6	-21
Northwest	54	-8	-14.8	-1
Other Western Interior	2,130	30	1.4	3
Gulf Region	8,612	-272	-3.2	-23
Total-All Regions	182,638	-5,567	-3.0	-464

Across all coal-producing regions, the estimated employment loss related to EIS Alternative 5 is 5,567 jobs over the 12-year period, and 464 jobs on an annual basis. The Appalachian Basin is projected to loss the greatest number of jobs: 4,679 over the 12 years and 390 jobs per year.

Employment losses in the other coal regions are expected to be much smaller. These data are described in Table 11 above.

The second approach to estimating the cost impacts of EIS Alternative 5 used a standard mining engineering economic approach developed by Morgan Worldwide, which did not involve the use of IMPLAN modeling. This second approach made full use of the coal production shift results from the mining engineering coal production forecast task force.

The per ton compliance cost estimates found in Table 9 above were used in this second cost analysis approach.

Table 12: Mining Engineering Cost Estimates to Comply with EIS Alternative 5, 2010-2022

Region	Underground			Surface			Total		Total Cost
	Tons (x ,000)	%	Cost/ Ton	Tons (x ,000)	%	Cost/Ton	Tons (x ,000)	Weighted Cost	
No. Rocky Mtns/Great Plains	4,213.80	0.70%	$0.25	618,499	99.30%	$0.19	622,713	$0.20	$121,331,210
Appalachian Basin	219,862.00	68.40%	$0.76	101,500	31.60%	$7.36	321,362	$2.84	$913,723,080
Illinois Basin	74,222.80	73.30%	$0.49	27,000	26.70%	$2.93	101,223	$1.15	$115,920,773
Colorado Plateau	55,370.00	62.70%	$0.19	33,000	37.30%	$1.05	88,370	$0.51	$44,932,193
Gulf Region	12,281.00	22.60%	$0.12	42,000	77.40%	$2.81	54,281	$2.20	$119,623,175
Other Western Interior									$0
Northwest	0	0.00%	0	1,000	100%	$2.41	1,000	$2.41	$2,407,211
Total	365,949.60			822,999			1,188,949	$1.11	$1,317,937,641

According to the analysis in Table 12, the total direct cost of complying with the SPR under EIS Alternative 5 would be $1.317 billion over the 12-year period, with the lion's share ($914 million) of this cost total occurring in the Appalachian Basin.

The Northern Rocky Mountain and Great Plains, Illinois Basin, and Gulf Basin regions would incur significant (in excess of $100 million over the 12 years) costs in complying with the rule.

Table 13 below provides annualized cost estimates for each of the 7 coal-producing regions. The average annual cost of complying with the rule would be $109.8 million across the 7 regions, with the largest share ($76,143,590) of this cost falling in Appalachia.

Table 13: Coal Regions' Annual Cost of Complying with SPR Under Alternative 5

Region	Annual Cost to Comply with EIS Alternative 5
No. Rocky Mtns/Great Plains	$10,110,934
Appalachian Basin	$76,143,590
Illinois Basin	$9,660,064
Colorado Plateau	$3,744,349
Gulf Region	$9,968,598
Other Western Interior	$0
Northwest	$200,601
Total	$109,828,137

The two cost estimating approaches ended up producing relatively simple overall cost numbers. The IMPLAN modeling approach showed a total cost over the 12 years of $1.357 billion (or $113 million per year) and the mining engineering costing approach produced a total cost over the 12 years of $1.317 billion (or $110 million per year).

EIS Alternative 2 (Most Stringent/Most Costly Alternative)

Alternative 2 assumes the SPR would be adopted and enforced in the most stringent way possible. In general, the alternative could hypothetically eliminate all surface mining across the United States due to its strict definition of a stream and the severe restrictions it would impose on mining activities. Table 14 below presents the mining engineering task force's estimates on production losses due to Alternative 2.

Table 14: **Forecasted Lost Coal Production Under EIS Alternative 2, 2010-2022**

	Lost Production (Million Short Tons)			Lost Production (%)		
Region	**Underground**	**Surface**	**Total**	**Underground**	**Surface**	**Total**
Northern Rocky Mountains and Great Plains	-	538.39	538.39	0.00%	100.00%	99.32%
Appalachian Basin	-	149.38	149.38	0.00%	100.00%	40.41%
Illinois Basin	-	34.27	34.27	0.00%	100.00%	34.66%
Colorado Plateau	-	34.28	34.28	0.00%	100.00%	38.07%
Gulf Region	0.00	54.10	54.10	0.02%	100.00%	81.50%
Other Western Interior	0.44	1.50	1.94	100.00%	100.00%	100.00%
Northwest	-	1.48	1.48	0.00%	100.00%	100.00%
Total	0.44	813.39	813.83	0.12%	100.00%	69.53%

The estimates in Table 14 indicate that 100% of surface mining and nearly 70% of all mining (surface and underground combined) nationwide would be lost due Alternative 2. These outcomes are catastrophic in nature. They would pose a dire threat to electric power generation

across much of the nation and would injure steel and other metals production. These impacts, while not measurable in economic terms, are believable to be very significant. One simple way to think about these impacts is to use the Baseline economic impact numbers from Tables 2 and 3 earlier in this report to create a quick estimate of the amount of this impact. First of all, almost 70% of current total coal production is from surface mining. The total economic impact of the coal mining industry on all U.S. states (coal-producing and non-coal-producing) is $82 billion. Over $57 billion (70%) of the total $82 billion economic impact could be roughly attributed surface mining. This amounts to an annualized loss of $4.75 billion. This would be potentially eliminated by the strict adoption of Alternative 2.

Within the 25 coal-producing states themselves, coal mining creates an economic impact of $48 billion. Almost $34 billion (70%) of this $48 billion in economic impact is tied to the surface mining of coal. This economic impact would be potentially eliminated by Alternative 2.

V. Economic Benefits (This will be expanded in a significant way before the January 5, 2011 submission to OSM.)

The SPR is expected to create significant environmental benefits, which will produce economic benefits nationally and in coal-producing areas. None of these benefits can be monetized at this time, and only some of them can be quantified because of the proposed nature of the rule and very limited quantitative data on these beneficial impacts. Once the EIS for the SPR has been completed and a final rule exists, an improved foundation for quantifying and monetizing these benefits will be possible. The chief economic benefits of the rule, stemming from its environmental benefits include:

1. Fewer miles of stream destroyed.
2. Conserved land acreage.
3. Improved protection of the biological condition of streams.
4. Added fish and wildlife habitat protection and enhancement.
5. Increased reforestation of lands used in mining.
6. Lessen adverse impacts on downstream water quality and groundwater during and after mining and reclamation.
7. Improved aesthetics of reclaimed lands.

Where available, quantitative data are offered to measure these benefits. In most cases however, quantifiable data are not available. A diligent effort was made to secure these data from OSM, the state regulatory agencies, EPA, the Energy Information Administration, and the Army Corps of Engineers. Some of this data will be available once the EIS is further along. This will be added in the final RIA.

Stream Mile Protection

A preliminary analysis of stream mile protection under EIS Alternative 5 was completed by Morgan Worldwide. The results are summarized in Table 15 below. This is best available information for use at this time. Once more precise stream mile protection data are available,

these will be included in the final RIA. Attempts were made to secure data from OSM, EPA, and the Army Corps of Engineers. No data was available for use in the Conceptual RIA.
Using an assumption on the stream density (ft per permit acre), a calculation of the current stream impact per annum was undertaken, and then that calculation was used to develop a stream impact per ton for each of the coal-producing regions. Using the redistribution of coal production under EIS Alternative 5, a new stream impact was prepared. As shown in Table 15, the baseline case has an annual impact of 3,657,700 ft, and Alternative 5 would have an impact of 2,731,254 ft, which is a reduction of about 25%.

Table 15: (Preliminary) Stream Mile Protection Under EIS Alternative 5

Baseline Case	**Surface Permitted Acres**	**Ft / Acre**	**Total Stream Length**	**Annual Stream Impact**		**Annual Surface Tonnage**	**Stream Impact per Surface Ton**
	Acres		Ft	Ft	Miles	(,000 tons)	ft/Ton
N Rocky Mountain / Great Plains	562,200	5	2,811,000	281,100	53.2	538,387	0.52
Appalachian Basin	1,107,160	20	22,143,200	2,214,320	419.4	149,376	14.82
Illinois Basin	254,880	15	3,823,200	382,320	72.4	34,266	11.16
Colorado Plateau	119,690	10	1,196,900	119,690	22.7	34,283	3.49
Gulf Region	409,920	15	6,148,800	614,880	116.5	54,099	11.37
Other Western Interior	30,790	10	307,900	30,790	5.8	1,499	20.54
Northwest	7,300	20	146,000	14,600	2.8	1,477	9.88
Total				**3,657,700**		813,387	
EIS Alternative 5	**Annual Stream Impact**	**Annual Surface Tonnage**	**Stream Impact per Ton**				
	Ft		ft/Ton				
N Rocky Mountain / Great Plains	322,928	618,499	0.52				
Appalachian Basin	1,504,616	101,500	14.82				
Illinois Basin	301,250	27,000	11.16				
Colorado Plateau	115,211	33,000	3.49				
Gulf Region	477,365	42,000	11.37				
Other Western Interior	0	0	20.54				
Northwest	9,885	1,000	9.88				
Total	**2,731,254**	822,999					
Baseline Case	**3,657,700**						

Alternative 5 Miles	**2,731,254**					
Stream Mile Savings	**926,446**					
Percentage Reduction	**25.3**					

Conserved Land Area

A second economic benefit of the SPR is conserved land that is protected during mining and can be made available as future open space/green space, or can be used for recreation, residential, agricultural and business uses. Table 16 below provides very basic baseline data on permitted acreage for coal mining in each of the regions. These data were collected by Morgan Worldwide.

Table 16: Baseline Permitted Acreage for Coal Mining by Coal Region

		Permitted Acreage		**Subtotal**	
Region	**State**	**Surface**	**Underground**	**Surface**	**Underground**
N Rocky/Great Plains	Wyoming	395,840	5,270		
	Montana	59,900	6,400		
	N. Dakota	106,460	0	562,200	11,670
App. Basin	West Virginia	269,950	31,160		
	Ky - East	436,230	933,450		
	Pennsylvania	295,800	47,700		
	Ohio	9,120	590		
	Virginia	64,560	7,440		
	Maryland	4,150	940		
	Tennessee	27,350	1,270	1,107,160	1,022,550
Illinois Basin	Indiana	194,710	7,480		
	Illinois	11,700	22,600		
	Ky-West	48,470	400,050	254,880	430,130
Col. Plateau	Colorado	45,100	118,800		
	New Mexico	74,150	13,220		
	Arizona				
	Utah	440	1,790	119,690	133,810
Gulf Region	Texas	285,600	0		
	Alabama	75,370	11,460		
	Louisiana	41,930	0		
	Mississippi	5,800	0		
	Arkansas	1,220	120	409,920	11,580
Other West	Oklahoma	21,600	300		
	Missouri	6,050	0		
	Kansas	3,140	0	30,790	300
Northwest	Alaska	7,300	1,250		

	Washington		0	7,300	1,250

Qualitative Insights about Other Economic Benefits of the Stream Protection Rule

A variety of environmental articles and reports discuss strategies to enhance the economic value of mined land. While these sources do not provide monetary or other quantitative information that can be readily used in the Conceptual RIA, a summary of some of these documents provides qualitative insights into the economic benefits of the SPR. These summaries are provided below.

1. Reforestation of land that has been surface mined for coal can produce high-value commercial forests while providing watershed protection and wildlife habitat. Forests growing on good quality mine sites can sequester 3 to 5 times more 4 carbon than the grasslands that were established through the original reclamation. Source: Burger, J.A., and C.E. Zipper. 2009. *Restoring the Value of Forests on Reclaimed Mined Land.* Virginia Cooperative Extension Publication 460-138.

2. Targeted reforestation on surface mines can reduce forest fragmentation that has been caused by mining, as needed to restore habitat for wildlife species that depend on large expanses of unbroken forest, including rapidly declining bird species such as the Cerulean Warbler and for species that depend on successional forest habitat. Source: Wickham, J.D., K. H. Riitters, T. G. Wade, M. Coan, and C. Homer. 2007. *The effect of Appalachian mountaintop mining on interior forest*. Landscape Ecology 22:179-187.

3. When conducted on favorable mines sites, establishment of bioenergy plantations approach profitability using conventional economic measures. Sources: Sullivan, J., J. Aggett, G. Amacher, and J. Burger. 2005. *Financial viability of reforesting reclaimed surface mined lands, the burden of site conversion costs, and carbon payments as reforestation incentives.* Resources Policy 30: 247-258. Susmita Sen, *Geospatial Environmental Analysis*, Virginia Tech. Ph.D. research and dissertation in preparation, planned for completion in 2010. Major advisors are R.H. Wynne and C.E. Zipper.

4. Forests have been the traditional land use and support an established industry throughout the eastern coalfields. Forests provide many benefits such as wildlife habitat, watershed control, carbon sequestration, and recreation. Source: Angel, P, V. Davis, J. Burger, D. Graves, and C. Zipper. 2005. *The Appalachian Regional Reforestation Initiative*, Forest Reclamation Advisory Number 1.

5. Re-establishing productive forests on otherwise unused and non-productive mined lands will generate economic value for landowners and communities, and will enhance environmental quality by accelerating restoration of ecosystem services – such as watershed protection, water quality enhancement, carbon storage and wildlife habitat – that are typically provided by native forests on non-mined landscapes. Source: Burger, J.A., and C.E. Zipper. 2010. *Reforestation Guidelines for Unused Surface Mined Lands in the Eastern United States.* Publication 460-144.

VI. Transfers

Because of the proposed nature of the rule, it is not possible to quantify or monetize any transfers of either costs or benefits that may be associated with the rule. Moreover, the requested scope of the RIA analysis was restricted primarily to the impact of the rule on the coal mining industry. These issues will be analyzed more thoroughly in the final RIA once a final rule exists. Three potential transfers should be considered for evaluation in the final RIA:

1. **Coal Production Shifts**: Considerable attention has been given to regional shifts in coal production and mining method shifts. These could be seen as a form of "transfer" of rule-related benefits and costs. Available data on these shifts was discussed earlier in this report. A few important summary points should be considered in the context of transfers:

    a. Regional Production Shifts: Analysis for both the EIS and RIA point to a potential loss of coal production from Eastern coal locations (principally the Appalachian Basin) to Western and Illinois Basin sources. It is important to note that these shifts have been underway for several years. It is likely that the SPR could add to these regional shifts. These future shifts could carry the economic benefits (production, sales, employment, payroll, and taxes) associated with coal mining in Eastern states to Illinois Basin and Western states. One potential impact of these regional shifts could also be increases and decreases in the coal revenues and profits of coal mining companies. Those companies with Western mining operations would appear to stand to gain, and those with their primary operations in the East could be placed at a disadvantage.

    b. Mining method shifts, especially those from surface mining to underground mining could have similar effects in benefitting coal companies in a position to capture the new underground mining business created by the shift from surface mining to underground mining.

2. **Costs Passed Along to Customers**: A second type of transfer could be represented by the actions by coal producers to pass along any increased cost of production related to the SPR to their customers, namely electric power companies and heavy metals (steel and other primary metals) manufacturing industries. Historically, coal producers have been able to pass along their increased costs to customers. Given the slowly recovering nature of the general economy, it may be more difficult for coal companies to pass along SPR costs to their customers.

3. **Intergovernmental and Private to Public Sector Cost Shifts**: A third potential type of transfer could relate to the transfer of any increased cost of production, mine site protection and reclamation, or other SPR-related cost from one level of government to another (for example an unfunded mandate created by the rule that creates added regulatory or environmental cleanup costs to state and local governments.) A second type of transfer in this category could be a transfer of rule compliance costs from a private

entity (coal mining company) to the public sector (federal, tribal, state or local government).

VII. Other Effects of the Stream Protection Rule

1. Regulatory Flexibility Act (Small Business Impact) Analysis

Purpose

This section presents and analyzes best available information on the economic impact of the Office of Surface Mining's (OSM's) proposed Stream Protection Rule (SPR) on small coal mining business entities. Available data from various sources have been examined and analyzed. This analysis is a part of the rule's Conceptual Regulatory Impact Analysis (RIA). A more complete analysis of these impacts will be conducted within the Final RIA on the Final Stream Protection Rule (SPR) when it exists.

Background and Definitions

An analysis of the economic impact of proposed federal regulations on small business entities (also known as firms, companies or enterprises) is a required component of a Regulatory Impact Analysis (RIA). Executive Order 13272, signed August 13, 2002, gave federal agencies new direction in their efforts to assess the impact of their proposed rulemakings on small businesses and other small organizations under the Regulatory Flexibility Act (RFA). It also directed the U.S. Small Business Administration's Office of Advocacy to provide agencies with information on how to comply with the President's directive.

By definition, the Regulatory Flexibility Act (RFA) is an effort by the federal government to balance the social goals of federal regulations with the needs and capabilities of small businesses and other small entities in American society.

Research indicates that smaller businesses bear a greater proportionate share of the burden of regulatory compliance costs. For firms employing fewer than 20 employees, the annual regulatory burden averaged $6,975 per employee during the 1995-2000 time period—almost 60 percent more than that of firms with more than 500 employees.[8] Small businesses, defined as firms employing fewer than 20 employees, bear the largest burden of federal regulations, according to available research.

As of 2008, small businesses (firms with less than 500 employees) faced an annual regulatory cost of $10,585 per employee, which was 36 percent higher than the regulatory cost facing large firms (defined as firms with 500 or more employees).[9]

---

[8] See W. Mark Crain and Thomas D. Hopkins, The Impact of Regulatory Costs on Small Firms, report no. PB2001-107067, prepared by Hopkins and Crain for the U.S. Small Business Administration, Office of Advocacy (Springfield, Va.: National Technical Information Service, 2001).

[9] See Nicole Crain and W. Mark Crain, The Impact of Regulatory Costs on Small Firms, for the U.S. Small Business Administration, Office of Advocacy under contract number SBAHQ-08-M-0466, September 2010.

Since the federal government began calculating the economic impact of the RFA in 1998, the law is estimated to have saved small entities (and the U.S. economy as a whole) more than $200 billion without undermining the broad purposes of the regulations it affects.[10]

Definition of a Small Coal Mining Business

The U.S. Small Business Administration (SBA) defines a small business in the coal mining industry (NAICS 2121) for RFA purposes as an entity employing fewer than 500 people.[11] While this definition is used in assessing the economic impact of the SPR on smaller coal mining entities, a more complete analysis of the coal mining industry by various employment size groups is provided.[12]

U.S. Coal Mining Industry Enterprise (Corporate) Profile

For RFA purposes, the coal mining industry is analyzed from two perspectives: 1) enterprise (corporate) basis; and 2) establishment (operating facility) basis. Because of differences in how the data are organized and reported, the two sets of numbers do not align completely, but they are close. *The most important data in fulfilling the RFA requirements is the corporate or enterprise data.*

Table 17 below analyzes the U.S. coal mining industry on an enterprise basis, identifying the number of firms, establishments and employment for coal mining, or NAICS 2121. An **establishment** is defined as a single physical location at which business is conducted or where services or industrial operations are performed. An **enterprise** is defined as a business organization consisting of one or more domestic establishments under common ownership or control. For companies with only one establishment, the enterprise and the establishment are often the same. The employment of a multi-establishment enterprise is determined by summing the employment of all associated establishments.

Table 17: U.S. Coal Mining Industry Enterprise Profile in 2007[13]

Enterprise Employment Size	Number Firms	Number Establishments	Employment	% Total Firms	% Total Establishments	% Total Employment
0-4	197	199	332	29.0	18.7	0.4

[10] Source: Analysis of Regulatory Flexibility Act (RFA) annual reports by the United States Small Business Administration on November 30, 2010 at: http://www.sba.gov/advo/laws/flex/

[11] U. S. Small Business Administration, Table of Small Business Size Standards Matched to North American Industry Classification System Codes, Update, November 5, 2010.

[12] NAICS stands for the North American Industry Classification System, which standardizes how operating businesses are classified for operating and government reporting purposes.

[13] Source: U.S Census, Statistics of U.S. Business Enterprises, 2007.

5-9	80	80	527	11.8	7.5	0.7
10-19	103	105	1,433	15.2	9.8	1.8
<20	380	384	2,292	56.0	36.0	2.9
20-99	194	215	8,284	28.6	20.2	10.4
100-499	64	142	12,392	9.4	13.3	15.5
<500	638	741	22,968	94.0	69.5	28.8
500+	41	325	56,880	6.0	30.5	71.2
Total	679	1,066	79,848	100.0	100.0	100.0

The U.S. coal mining industry in 2007, analyzed on an enterprise (firms) basis, consisted of 679 total firms, or corporate entities, which operated 1,066 mining operations employing 79,848 people. 56% of the industry's total firms had 20 or fewer employees and 94% had less than 500 employees.

On an employment basis, only 2.9% (2,292 jobs) of coal mining enterprise employment was accounted for by coal enterprises with less than 20 employees. Coal enterprises with employment less than 500 people accounted for 29% of total employment, while coal enterprises with more than 500 employees represented 71% of total employment.

U.S. Coal Mining Industry Revenues by Small and Large Businesses

Table 18 below analyzes coal revenues produced by small and large coal mining businesses.

Table 18: Coal Mining Receipts (Revenues) by Small and Large Businesses in 2007[14]

Industry Receipts Size Group (Dollars)	Firms	Employ.	Estimated Receipts ($000)	Avg. Firm Employ. Size	Avg. Firm Receipts ($000)	No. Firms with Avg. Employ <500	% Industry Total Receipts
Total	679	79,848	33,550,214	118	49,411	620	100.0%
<100,000	24	0	0	0	0	24	0.0%
100,000-499,999	278	2,092	105,063	8	378	278	0.3%
500,000-999,999	25	80	16,473	3	659	25	0.0%
1,000,000-2,499,999	40	518	71,559	13	1,789	40	0.2%
2,500,000-4,999,999	50	1,294	184,756	26	3,695	50	0.6%
5,000,000-7,499,999	44	1,422	275,296	32	6,257	44	0.8%
7,500,000-9,999,999	27	1,146	236,338	42	8,753	27	0.7%
10,000,000-14,999,999	47	2,336	590,449	50	12,563	47	1.8%

[14] Source: U.S Census, Statistics of U.S. Business Enterprises, 2007.

15,000,000-19,999,999	18	1,107	323,721	62	17,985	18	1.0%
20,000,000-24,999,999	11	819	254,100	74	23,100	11	0.8%
25,000,000-29,999,999	9	935	225,935	104	25,104	9	0.7%
30,000,000-34,999,999	5	462	142,363	92	28,473	5	0.4%
35,000,000-39,999,999	7	548	250,861	78	35,837	7	0.7%
40,000,000-44,999,999	2	0	0	0	0	2	0.0%
45,000,000-49,999,999	3	0	0	0	0	3	0.0%
50,000,000-74,999,999	24	3,512	1,444,888	146	60,204	24	4.3%
75,000,000-99,999,999	6	NA	NA	NA	NA	6	NA
100,000,000+	59	61,596	28,810,646	1,044	488,316	0	85.9%
% Defined as Small Business (<500 Employees)	91.3%						
% Industry Receipts by Small Businesses	14.1%						

The data in Table 18 indicates that 14.1% of the coal mining industry's total receipts (revenues) in 2007 was produced by coal firms employing less than 500 people, or small businesses. The remaining 85.6% of industry receipts come from coal firms that employ 500 or more employees, or large businesses.

U.S. Coal Mining Industry Business Legal Form Profile

The analysis in Table 19 below indicates that on an establishment basis over 48% of total coal mining business establishments (operations) employed less than 20 people and almost 98% employed less than 500 people. Only 2.3% of all coal mining establishments employed over 500 people in 2008 according to the data in Table 3.

Almost 78% of all coal mining establishments are associated with corporations or S-corporations, and the other 22% are associated with sole proprietorships and partnerships, which tend to be smaller in employment size than corporate entities.

Table 19: U.S. Coal Mining Industry Business Legal Form Profile, 2008[15]

Business Legal Type	Total Establish	<20 Employ	20-499 Employ	>500 Employ	% <20 Employ	% 20-499 Employ	% >500 Employ	Totals
All Establishments	1108	536	547	25	48.4%	49.4%	2.3%	100.0%

[15] U.S. Census, County Business Patterns 2008

Corporations	546	214	221	240	39.2%	57.3%	3.5%	100.0%
S-Corporations	318	172	164	169	54.1%	45.6%	0.3%	100.0%
Sole Proprietorships	44	33	19	11	75.0%	22.7%	2.3%	100.0%
Partnerships	198	117	86	79	59.1%	38.9%	2.0%	100.0%
Other	2	0	1	1	0.0%	100.0%	0.0%	100.0%

Coal Production and Revenues by Mine Type and Employment Size

The Mine Safety and Heath Administration (MSHA) within the U.S. Department of Labor classifies establishments (mines) in the U.S. coal mining industry into three major coal commodity groups: bituminous, lignite, and anthracite.[16] Bituminous operations represent approximately 97% of coal mining operations and approximately 99% of coal miners and total coal production. Anthracite operations represent approximately 2% of coal mining operations and less than 1% of coal miners and total coal production. Lignite operations represent less than 1% of coal mining operations, coal miners, and total coal production.

The U.S. surface coal mining industry produced an estimated 742.5 million short tons in 2009. The average price of coal in surface mines in 2009 was $22.35 per short ton. The U.S. underground coal sector produced an estimated 332 million short tons in 2009. The average price of coal in underground mines in 2009 was $51.35 short per ton. Table 4 below presents the coal production and revenues for 2009.

A diligent effort was made to acquire firm or corporate level data on coal production and revenues from MSHA, but it is not available since employment data are not included in the agency's corporate data files. Employment data at the mine (establishment) level are available in the MSHA database, which were used in Table 20 to analyze coal production and revenues by the employment size of mines. Because of data reporting problems, mine (establishment) production and revenue data could not be aggregated at the firm or corporate level in a valid way.

Table 20: Coal Production by Mines in Short Tons and Coal Revenues in 2009

Coal Production by Mines in Short Tons			
Mine Size	Coal-Surface	Coal-UG	Total
1-19 Employees	19,713,676	5,036,046	24,749,722
20-499 Employees	475,066,642	236,566,737	711,633,379
500+ Employees	247,760,869	90,256,010	338,016,879
Grand Total	742,541,187	331,858,793	1,074,399,980
Total Coal Revenues, Apportioned by Coal Tonnage Produced			

[16] This categorization is based on MSHA-collected data grouped by Standard Industrial Classification (SIC) code description. Some publications of the U.S. Department of Energy further divide the bituminous group into bituminous coal and sub-bituminous coal.

Mine Size	Coal-Surface	Coal-UG	Total
1-19 Employees	$440,600,659	$258,600,962	$699,201,621
20-499 Employees	$10,617,739,449	$12,147,701,945	$22,765,441,394
500+ Employees	$5,537,455,422	$4,634,646,114	$10,172,101,536
Grand Total	$16,595,795,530	$17,040,949,021	$33,636,744,551

Source: Mine Safety and Health Administration (MSHA) Employment and Production Database

Over 66% of total coal production (including both surface and underground mined) in 2009 was produced by mines with employment in the 20-499 range, which are considered to be small businesses. Almost 69% of total coal production occurred in mining operations with less than 500 employees. About 2% of total coal revenues was produced by mines with less than 20 employees.

Coal Production Concentration

According to U.S. Energy Information Administration (EIA) industry survey data, U.S. coal production is highly concentrated. The five largest corporate producers represent over 53% of total coal production in 2009, according to the data presented in Table 5 below. The 29 coal producers listed in Table 21 account for over 87% of total U.S. coal production.

Table 21: Largest U.S. Coal Producers in 2009

Rank	Controlling Company Name	Production (Thou. Short Tons)	Percent of Total Production
1	Peabody Energy Corporation	189,232	17.6
2	Arch Coal Inc.	148,061	13.8
3	Cloud Peak Energy	90,965	8.5
4	Alpha Natural Resources LLC	83,523	7.8
5	CONSOL Energy Inc.	58,145	5.4
6	Massey Energy Co.	37,161	3.5
7	NACCO Industries Inc.	31,085	2.9
8	Patriot Coal Corp.	29,268	2.7
9	Peter Kiewit Sons Inc.	27,136	2.5
10	Alliance Resource Operating Partners LP	25,874	2.4
11	Murray Energy Corp.	25,837	2.4
12	Westmoreland Coal Co.	24,266	2.3
13	Energy Future Holdings Corp.	21,272	2.0
14	Drummond Co. Inc.	19,964	1.9
15	Intl Coal Group Inc. (ICG)	17,414	1.6
16	BHP Billiton Ltd.	14,917	1.4
17	James River Coal Co.	9,855	0.9
18	Chevron Corp.	9,841	0.9
19	PacifiCorp	9,447	0.9

20	Level 3 Communications	8,392	0.8
21	Walter Industries Inc.	7,571	0.7
22	Trinity Coal Corp.	6,805	0.6
23	Booth Energy Group	6,506	0.6
24	Cline Group	6,497	0.6
25	TECO Energy Inc.	6,205	0.6
26	Rosebud Mining Co.	6,084	0.6
27	Black Hills Corp.	6,016	0.6
28	Oxbow Carbon & Minerals Holding Inc.	5,703	0.5
29	Western Fuels Association Inc.	5,234	0.5
	Subtotal	**938,276**	**87.3**
	All Other Coal Producers	**136,647**	**12.7**
	U.S. Total	**1,074,923**	**100.0**

Source: Energy Information Administration, U.S. Department of Energy, 2010 Annual Coal Outlook Report, May 2010

Earlier Relevant RFA Analyses

A preliminary RFA analysis was conducted for OSM's Excess Spoil; Stream Buffer Zones; Diversions Rule in 2008. The analysis did not find any major economic impacts of that rule on small mining operations and companies. The cost impact of the rule was estimated at $240,000, which was related to increased monitoring and reporting requirements created by the rule.

Major Observations and Summary

1. Research suggests that small businesses are generally impacted in a significant economic way by federal regulations. For this reason, it is important to carefully consider the economic impacts of the SPR on smaller coal mining companies.

2. The U.S. coal mining industry is represented by a large and significant number of small businesses, defined as those employing less than 500 people. The U.S. coal mining industry in 2007, analyzed on an enterprise (company) basis, consisted of 679 total firms, or corporate entities, which operated 1,066 mining operations employing 79,848 people. Almost 56% of the industry's total firms had 20 or fewer employees and 94% had less than 500 employees. See Table 1.

3. 14.1% of the coal mining industry's total receipts (revenues) in 2007 was produced by coal firms employing less than 500 people, or by small businesses. This amounts to revenues of $4.73 billion. The remaining 85.9% ($28.8 billion) of industry receipts come from coal firms that employ 500 or more employees, or large businesses. See Table 2.

4. Analyzed on an establishment (mine operations) basis, over 48% of total coal mining business establishments employed less than 20 people and almost 98% employed less than 500 people. See Table 3.

5. On an employment basis, only 2.9% (2,292 jobs) of coal mining enterprise employment is accounted for by coal enterprises with less than 20 employees. Coal enterprises with employment less than 500 people accounted for 28.8% of the industry's total employment, while coal enterprises with more than 500 employees represented 71.2% of the industry's total employment. This indicates that coal employment is heavily concentrated in larger coal mining enterprises or companies and not smaller ones. See Table 1.

6. According to the economic analysis for the RIA, the baseline (pre-SPR) national economic impact (industry output) of the coal mining industry is presently $48.7 billion. This economic impact generates a total national employment impact of 182,785 jobs. If coal mining enterprises employing less than 500 people account for 28% (22,968) of the coal industry's direct employment (79,848 jobs), then it is fair to assume that coal mining enterprises with less than 500 employees also account for 28% of the industry total economic and employment impacts. This means that currently (in the pre-SPR environment) smaller coal enterprises account for an estimated $13.6 billion of the industry's total national economic impact and an estimated 51,180 of the industry's total employment impact.

7. The economic analysis for the RIA shows that under Economic Impact Analysis Scenario One (which corresponds to the EIS Alternative 5 or the proposed preferred alternative) the national economic impact of the coal industry would be reduced by $1.36 billion over a 12-year period, which represents a 2.8% overall reduction in the industry's economic impact. On an annual basis over the 12 years, this represents a $113.3 million reduction in coal mining industry economic output. It is also estimated that 5,567 jobs would be lost nationally over the 12 years under RIA Scenario One (EIS Alternative 5) as a result of this $1.36 billion economic output reduction. On an annual basis, this represents a 464-job loss per year over the 12 years. If we assume that smaller coal mining enterprises would experience equal reductions in their economic impact (-2.8%) and employment impact (-3.0%), then the economic contribution of smaller mining enterprises would be reduced by $380 million ($13.6 billion x .028) over the 12 years ($31.7 million per year), and the employment contribution of these operations would be reduced by 1,530 jobs (51,000 jobs x .030) over the 12 years, or by 128 jobs per year.

8. We are unable to estimate the economic impact of the Most Stringent Alternative (EIS Alternative 5) because of insufficient data to conduct this analysis. It is known from a recent mining engineering forecast for the EIS that Alternative 5, if adopted, could trigger a 100% loss (814 million tons) of surface mining production across the United States. Using MSHA data, we estimate that surface mining operations account for 69% (743 million tons) of total coal production. Moreover, 67% of all surface mining production is accomplished by small coal mining operations (with less than 500 employees). From this

standpoint, the economic impact of Alternative 2 on small mines and small mine enterprises would be catastrophic in nature. It could eliminate all of them.

9. Using the 2008 Excess Spoils and Stream Buffer Rule as the Least Stringent Alternative, we know the economic impact of the 2008 rule was expected to be very minimal or insignificant from an economic impact standpoint. The economic impact of the 2008 rule was assessed to be minimal in its RFA analysis.

10. The overall conclusion of this analysis is that: a) smaller coal mining companies could be economically impacted in a catastrophic way by the EIS Alternative 5 (Most Stringent Version), if it is adopted; b) they would impacted in an economically significant way by EIS Alternative 2 (Proposed Preferred Rule Version); and c) smaller coal mining businesses would not be impacted in any economically significant way by the baseline situation, which is represented by the 2008 Rule, which was not implemented upon its adoption.

Table 22: Small Business Profile Summary [17]

Coal Companies	Business Size Definition[18]	Number Firms	% Total Firms	% Total Industry Employment Total: 79,848	%Total Industry Revenues Total: $33.6 Billion	%Total Industry Production Total: 1.074 billion tons
Small Businesses	<500 Employees	638	93.9%	28.8%	14.1%	68.5%
Large Businesses	>500 Employees	41	6.1%	71.2%	85.9%	31.5%
Totals		679	100%	79,848	100%	100%

Table 23: Small Business Impact Summary

Impact	EIS Alternative 5 (Proposed Preferred Rule)	EIS Alternative 2 (Most Stringent Rule)	Least Stringent Rule (2008 Excess Spoils & Stream Buffer Rule)
Reduced Total Economic Output Impact (Over 12 years)	-$380 Million	Devastating impact on small mining companies. 100% elimination of surface mining across the U.S.	No significant economic impact on small mining companies
Reduced Annual Economic Output Impact $380 million/12 years)	-$31.7 Million		
Reduced Total Employment Impact	-1,530 Jobs		

[17] All data are for firms or companies except the production data, which relates to mines or business establishments.
[18] Reflects the U.S. SBA size standards for the coal mining industry, which must be used in the Regulatory Flexibility Act (RFA) analysis for the SPR.

(Over 12 years)			
Reduced Annual Employment Impact (1,530/12 years)	-128 Jobs		

2. Effects on State, Local, and Tribal Governments

Possible effects were described briefly under the Transfers Section of this document. Possible effects were identified, but quantification and monetization of these effects is not possible at this time given the proposed nature of the rule and the lack of data to measure these effects.

The public comments offered during the Scoping Phase of the EIS included some mention of these issues as concerns, but no quantitative was included with these comments.

Earlier EIS and RIA reports related to the coal mining industry were reviewed, including the final EIS for the 2008 Stream Buffer Zone rule.

3. Effects on Wages and Growth

Possible effects on the growth of the coal mining industry and the general economy should be considered. With respect to the coal mining industry, the SPR could result in reduced coal production and revenues to coal companies. These potential impacts have been accounted in the analysis conducted on the three alternatives examined in the Conceptual RIA.

Effects on wages in the coal mining industry are not clear at this point. In general, the economic downturn has worked against wage increases. Wage decreases are not likely related to the rule, but they may be sparked by labor-management negotiations in efforts to maintain employment levels during the slow economy.

The negative effects of coal companies passing future production cost increases due to the SPR on to customers was discussed above in the Transfers Section. This is a possible concern that should be examined in the final RIA.

VIII. Summary

Table 23, which is required for OSM's submission to OMB serves as an overall summary of the economic costs, benefits, and other effects of the proposed Stream Protection Rule.

Table 23: Required OMB Regulatory Impact Analysis Table for Conceptual RIA, for the Period 2010-2022

Category	Primary Estimate: EIS Alternative 5 (Proposed Preferred Rule)	Minimum Estimate: EIS Alternative 1: Baseline Situation (Least Stringent and Least Costly)	Maximum Estimate: EIS Alternative 2: (Most Stringent and Most Costly)	Source Citation

Category	Primary Estimate: EIS Alternative 5 (Proposed Preferred Rule)	Minimum Estimate: EIS Alternative 1: Baseline Situation (Least Stringent and Least Costly)	Maximum Estimate: EIS Alternative 2: (Most Stringent and Most Costly)	Source Citation
Benefits:				
Annualized Monetized Benefits	They exist but cannot be monetized at this stage.	None known[19]	They exist but cannot be monetized at this stage.	This summary document pages 22-25.
Annualized Quantified, but Non-Monetized Benefits	Stream miles protected and land acreage conservation.	None known	Stream miles protected and land acreage conservation	This summary document pages 22-25.
Non-Quantified Benefits/Qualitative Benefits	Future land and water uses enabled by the rule.	None known	Future land and water uses enabled by the rule.	This summary document pages 22-25.
Costs:				
Annualized Monetized Costs	$109-113 million in production and sales and 464 jobs per year.	None known	$4.75 billion in production and revenues across all 50 states and $2.74 billion in production and revenues to the 25 coal producing states.	This summary document pages 11-21. “ “
Annualized Quantified, but Non-Monetized Costs	None available (should be examined in the final RIA)[20]	None known	None available (should be examined in final RIA)	“ “
Non-Quantified Costs/Qualitative Costs	None known	None known	Extensive damage to the economic health of the coal mining industry and the ripple effects of this damage to the general economy.	This summary document pages 11-21.
Transfers:				
Annualized Monetized Transfers	None available (should be examined in final RIA)	None known	None available (should be examined in final RIA)	This summary document pages 25-26.

[19] “None known” refers to the fact that it is not believed there is an impact or effect.

[20] “None available (should be examined in the final RIA)” refers to the fact that is believed there is an impact, but no definitive data or information about the impact is available at this time.

Category	Primary Estimate: EIS Alternative 5 (Proposed Preferred Rule)	Minimum Estimate: EIS Alternative 1: Baseline Situation (Least Stringent and Least Costly)	Maximum Estimate: EIS Alternative 2: (Most Stringent and Most Costly)	Source Citation
From Whom to Whom	None available (should be examined in final RIA)	None known	None available (should be examined in final RIA)	“ “
Annualized Monetized Transfers (Off Budget)	None available (should be examined in final RIA	None known	None available (should be examined in final RIA	“ “
Effects:				This summary document pages 26-36.
Effects on State, Local, and Tribal Governments	None available (should be examined in final RIA	None known	None available (should be examined in final RIA	
Effects on Small Businesses	-$31.7 million per year in reduced business. -128 jobs per year.	Insignificant ($240,000 for monitoring over time for 2008 rule	None available (should be examined in final RIA	“ “
Effects on Wages		None known	None available (should be examined in final RIA	“ “
Effects on Growth		None known	None available (should be examined in final RIA	“ “

Discount Rates

A net present value (NPV) analysis was conducted on the proposed preferred rule (Alternative 5). The results are provided in Table 24 below. Because of the more generalized nature of the economic impact of EIS Alternative 1 (Least Stringent and Costly/Baseline/2008 Rule) and the EIS Alternative 2 (Most Stringent and Costly Rule), no discounting of presented numbers was done.

Table 24: 3% and 7% Discount Analysis of EIS Alternative 5 (Proposed Preferred Rule)

3% Discount Rate				7% Discount Rate		
Year	**Amount**	**Present Value**		**Year**	**Amount**	**Present Value**
0	0	0		0	0	0
1	0	0		1	0	0
2	0	0		2	0	0
3	$135,712,895	$135,712,895		3	$135,712,895	$135,712,895
4	$135,712,895	$135,712,895		4	$135,712,895	$135,712,895
5	$135,712,895	$135,712,895		5	$135,712,895	$135,712,895
6	$135,712,895	$135,712,895		6	$135,712,895	$135,712,895
7	$135,712,895	$135,712,895		7	$135,712,895	$135,712,895
8	$135,712,895	$135,712,895		8	$135,712,895	$135,712,895
9	$135,712,895	$135,712,895		9	$135,712,895	$135,712,895
10	$135,712,895	$135,712,895		10	$135,712,895	$135,712,895
11	$135,712,895	$135,712,895		11	$135,712,895	$135,712,895
12	$135,712,895	$135,712,895		12	$135,712,895	$135,712,895
Totals	$1,357,128,953	$1,357,128,953		Totals	$1,357,128,953	$1,357,128,953

Appendix 1: U.S. Energy Information Administration's 2010 Coal Forecast Assumptions

Source Document: Assumptions to the Annual Energy Outlook 2010
Report #: DOE/EIA-0554(2010)
Release date: April 9, 2010
Next release date: April 2011

Coal Market Module

The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2010, DOE/EIA-M060(2010) (Washington, DC, 2010).

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Forty separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

* As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.

* Between 1980 and 1999, U.S. coal mining productivity increased at an average rate of 6.7 percent per year from 1.93 to 6.61 tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[1] Since 1999, however, growth in overall U.S. coal mining productivity has slowed substantially, decreasing at a rate of 1.1 percent per year to 5.96 tons per miner hour in 2008. By region, productivity in most of the coal producing basins represented in the CMM has declined some during the past 5 years. In the Central Appalachian coal basin,

which has been mined extensively, productivity declined by a significant 33 percent between 1999 and 2008, corresponding to an average decline of 4.4 percent per year.

Over the projection period, labor productivity is expected to decline in most coal supply regions, reflecting the trend of the previous five years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

In the CMM, different rates of productivity improvement are assumed for each of the 40 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies. [2] Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the Energy Information Administration's Form EIA-7A, Coal Production Report. In the reference case, overall U.S. coal mining labor productivity declines at rate of 0.3 percent a year between 2008 and 2035. Reference case projections of coal mining productivity by region are provided in Table 12.1.

* With the exception of the AEO2010 Low and High Coal Cost Cases, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2008 dollars (i.e., increase at the general rate of inflation) over the projection period. This assumption primarily reflects the recent trends in these cost variables.

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 10) and 16 demand regions (Figure 11) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial coal demand are provided by the petroleum market, industrial, commercial, and residential demand modules, respectively; electricity coal demands are projected by the EMM; coal imports and coal exports are projected by the CMM based on non-U.S. coal supply availability, endogenously determined U.S. import demand, and exogenously determined world coal demand (non-U.S.).

The key assumptions underlying the coal distribution modeling are:

* Base-year (2008) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve.

Delivered price data are from Form EIA-3, Quarterly Coal Consumption Report-Manufacturing Plants, Form EIA-5, Quarterly Coke Consumption and Quality Report, Coke Plants, Form EIA-923, Power Plant Operations Report, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, Coal Production Report.

* For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars). [3]

* Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The east index is a function of railroad productivity, the user cost of capital for railroad equipment, and national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, a risk premium is added to the cost of borrowing in order to account for the possibility that greenhouse gas emissions may be regulated in the future. The west index is a function of railroad productivity, investment, and western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2010 reference case, eastern coal transportation rates are projected to be the same in 2035 and western rates are projected to be 5 percent higher in 2035 compared to 2008.

* For the projection period, the explanatory values are assumed to have varying impacts on the calculation of the indices. For the west, investment is the analogous variable to the user cost of capital of railroad equipment. The investment value and the PPI for rail equipment which is used to derive the user cost of capital increase with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance). Increases in investment (west) or the user cost of capital for railroad equipment (east) cause projected transportation rates to increase. For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, productivity is held flat for the projection period for both regions. For the east for the projection period, diesel fuel is removed from the equation in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program. The transportation rate indices for seven AEO2010 cases are shown in Table 12.2.

* Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.

* For AEO2010, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100 percent of all coal shipments are subject to the surcharge program.

* Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2008) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the EIA-923, Power Plant Operations Report. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data from information reported on the Form EIA-923, Power Plant Operations Report, historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.

* Electric generation demand received by the CMM is subdivided into “coal groups” representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

* Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 652 MW and the capability of producing 50,000 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 46 percent of the energy input is retained in the product with the remaining energy used for

conversion (38 percent) and for the production of power sold to the grid (17 percent). The liquid products produced include naptha, kerosene, and diesel. For AEO2010, coal-biomass-to-liquids capability has been incorporated into the NEMS structure. These facilities have the same operating features as CTL plants except 80 percent of the energy input is derived from coal with the remaining 20 percent derived from biomass.

Coal Imports and Exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

* Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

* Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

* U.S. coal exports are determined, in part, by the projected level of world coal import demand. World steam and metallurgical coal import demands for the AEO2010 cases are shown in Tables 12.3 and 12.4.

* Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

* Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Coal Quality

Each year the values of base year coal production, heat, sulfur and mercury (Hg) content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost and quality of fossil

fuels delivered to generating facilities, the Form EIA-5 which records the origin, cost, and quality of coal receipts at domestic coke plants, and the Form EIA-3, which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu, shown in Table 71, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emission factors for each coal type are shown in Table 12.5 in pounds of carbon dioxide emitted per million Btu. [4]

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

Legislation and Regulations

The AEO2010 is based on current laws and regulations in effect before October 31, 2009.

The AEO2010 reference case incorporates provisions of the Clean Air Act Amendments of 1990 as they apply to SO2 and NOx emissions.

The Clean Air Mercury Rule (CAMR) and the Clean Air Interstate Rule (CAIR) are additional rules promulgated by EPA related to coal emissions but were vacated by the courts in February and July 2008, respectively. CAIR addresses further SO2 emissions and seasonal and annual NOx emissions while CAMR addresses mercury emissions. As a result of the court ruling, CAMR is not included in the AEO2010 reference case and, in the absence of a cap-and-trade system, mercury allowance prices are not modeled. However, with or without CAMR, many States were planning to implement mercury rules of their own. For those States, the effects of state laws are approximated and modeled for the AEO2010. CAIR, however, was temporarily reinstated by the courts in December 2008 and is included in AEO2010.

The Energy Improvement and Extension Act of 2008 (EIEA) passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008. Subtitle B provides investment tax credits for various projects sequestering CO2. These provisions are assumed to result in 1 gigawatt of advanced coal-fired capacity with carbon capture and sequestration by 2017 in the AEO2010 reference case. Subtitle B also extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018 and is also modeled in the AEO2010.

Title IV, under Energy and Water Development, of the American Recovery and Revitalization Act of 2009 (ARRA), provides $3.4 billion for additional research and development on fossil energy technologies. This includes $800 million to fund projects under the Clean Coal Power Initiative (CCPI) program, focusing on projects that capture and sequester greenhouse gases. In July 2009, a total of $408 million, was allocated to two projects, the Basin Electric Power

Cooperative's Antelope Valley Station in North Dakota and the Hydrogen Energy Project in California, to collectively demonstrate the capability to capture 3,000,000 tons of carbon dioxide per year. In December 2009, three additional project awards were announced through the CCPI program and will receive part of their government funding through ARRA. These projects include American Electric Power's Mountaineer plant in West Virginia (235 megawatt flue gas stream), Alabama Power's Barry plant in Alabama (160 megawatt flue gas stream), and a new plant to be built by Summit Texas Clean Energy in Texas. To reflect the impact of this provision, the AEO2010 reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

Title XVII of the Energy Policy Act of 2005 authorizes loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. For AEO2010, The 2 gigawatts of advanced coal-fired capacity with carbon capture and sequestration assumed for EIEA and ARRA are also assumed to benefit from these loan guarantees.

Beginning in 2009, electricity generating units of 25 megawatts and greater are required to hold an allowance for each ton of CO2 emitted in 10 Northeastern States as part of the Regional Greenhouse Gas Initiative (RGGI). The States participating in RGGI include Connecticut, Maine, Maryland, Massachusetts, Rhode Island, Vermont, New York, New Jersey, New Hampshire, and Delaware. RGGI is modeled in AEO2010 as an emissions reduction for the Middle Atlantic region.

Coal Alternative Cases

Coal Cost Cases

In the reference case, coal mine labor productivity is assumed to decline on average by 0.3 percent per year through 2035 while miner wage rates and mine equipment costs remain constant in 2008 dollars. Eastern and Western transportation rates are flat and 5 percent higher, respectively, in 2035 compared to 2008. In two alternative coal cost cases, productivity, average miner wages, equipment cost, and transportation rate assumptions were modified for 2010 through 2035 in order to examine the impacts on U.S. coal supply, demand, distribution and prices.

In the low mining cost case, coal mine labor productivity is assumed to increase at an average rate of 3.2 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine suppy costs are all assumed to be about 25 percent lower by 2035 in real terms in the low coal cost case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower by 2035.

In the high mining cost case, coal mine labor productivity is assumed to decline at an average rate of 3.0 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine supply costs are assumed to be about 30 percent higher by 2035. Compared to the reference case, coal transportation rates are assumed to be 25 percent higher by 2035.

The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

No Greenhouse Gas Concern Case

In the reference case, to reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without carbon capture and sequestration technology and new coal-to-liquids plants is assumed. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation nor does it affect the operation of existing plants. This adjustment was first implemented for AEO2009.

The No GHG concern case excludes the 3-percentage point increase in the cost of capital.

Appendix 2: Assumptions and Methodology Used by the Mining Engineering Task Force to Forecast Coal Production Shifts

Step-By-Step Explanation of Alternative Impact on Production (Metrics)

Step 1: Baseline Data:

The baseline data comes from the 2008 DOE/EIA production reports as shown in the following table:

				CURRENT PRODUCTION			
				Alternative 1			
Region	States	Number of Mines	Heat Content (MM Btu / Ton)	Underground (MM ton)	Surface (MM ton)	Total Production (MM ton)	Total (Trillion Btu)
N Rocky Mountain / Great Plains	Wyoming	20	17.13	3.50	464.14	467.64	8,009.11
	Montana	6		0.17	44.62	44.79	767.01
	North Dakota	4		-	29.63	29.63	507.41
				3.67	**538.39**	**542.06**	**9,283.53**
Appalachian Basin	West Virginia	301	24.61	88.37	69.41	157.78	3,882.22
	Kentucky - East	446		44.14	46.12	90.26	2,220.88
	Pennsylvania	266		53.32	12.10	65.41	1,609.53
	Ohio	48		17.05	9.20	26.25	645.92
	Virginia	114		15.81	8.91	24.71	608.08
	Maryland	21		0.75	2.11	2.86	70.37
	Tennessee	23		0.79	1.54	2.33	57.40
				220.23	**149.38**	**369.61**	**9,094.40**
Illinois Basin	Indiana	30	22.44	12.22	23.67	35.89	805.37
	Illinois	19		27.06	5.86	32.92	738.61
	Kentucky -	23		25.33	4.73	30.06	674.58
				64.61	**34.27**	**98.88**	**2,218.56**
Colorado Plateau	Colorado	12	21.47	24.37	7.66	32.03	687.76
	New Mexico	5		7.05	18.60	25.65	550.68
	Arizona	1		-	8.03	8.03	172.32
	Utah	9		24.37	-	24.37	523.19
				55.78	**34.28**	**90.06**	**1,933.96**
Gulf Region	Texas	11	13.15	-	39.02	39.02	512.98
	Alabama	59		12.28	8.33	20.61	270.98
	Louisiana	2		-	3.84	3.84	50.53
	Mississippi	1		-	2.84	2.84	37.37
	Arkansas	2		0.00	0.07	0.07	0.91
				12.28	**54.10**	**66.38**	**872.76**
Other Western Interior	Oklahoma	7	22.74	0.44	1.02	1.46	33.29
	Missouri	2		-	0.25	0.25	5.62
	Kansas	2		-	0.23	0.23	5.21
				0.44	**1.50**	**1.94**	**44.12**
Northwest	Alaska	1	15.48	-	1.48	1.48	22.86
	Washington	-		-	-	-	-
				-	**1.48**	**1.48**	**22.86**
TOTAL				**357.01**	**813.39**	**1,170.40**	**23,470.19**

Step 2: Production Losses (Tons):

This preliminary approach to the quantification of the impact of the implementation of the various alternatives on the regional production was based on an **informal elicitation process** in which Steve Gardner, Doug Mynear, Joe Zaluski, John Morgan and Edmundo Laporte, estimated the tons that would be lost at each region.

The elicitation process is a method of subjective probabilities in which an expert or experts are asked to estimate various behaviors and likelihoods regarding specific model variables or scenarios. This method has seen increasing usage in environmental risk assessment and is used by **EPA** (EPA/630/R-97/001, March 1997)

Expert elicitation can be informal or formal. Informal elicitation methods include self assessment, brainstorming, causal elicitation (without structured efforts to control biases), and taped group discussions between the project staff and selected experts.

Formal elicitation methods generally follow the steps identified by the U.S. Nuclear Regulatory Commission (USNRC, 1989; Oritz, 1991; also see Morgan and Henrion, 1990; IAEA, 1989; Helton, 1993; Taylor and Burmaster; 1993) and are considerably more elaborate and expensive than informal methods.

Following NCRP's definition of an expert (NCRP 1996), an expert has (1) training and experience in the subject area resulting in superior knowledge in the field, (2) access to relevant information, (3) an ability to process and effectively use the information, and (4) is recognized by his or her peers or those conducting the study as qualified to provide judgments about assumptions, models, and model parameters at the level of detail required. Therefore, the individual who participated in the elicitation process, as mentioned above, are experts and, therefore, the described elicitation process is valid.

A more detailed analysis would require a formal elicitation process through which probabilistic ranges of impact would be defined by the experts. Those ranges would then be used to build a stochastic prediction model (Monte Carlo simulation).

The following table shows the estimated losses (tons) corresponding to the implementation of **Alternative 4** as estimated during the informal elicitation process:

Step 2: Production Losses (Tons) (Part 2):

		TONNAGE LOSSES		
		Alternative 4		
Region	States	Underground (MM ton)	Surface (MM ton)	Production (MM ton)
N Rocky Mountain / Great Plain	Wyoming	-		-
	Montana	-		-
	North Dakota	-		-
		-	-	-
Appalachian Basin	West Virginia	0.37	7.41	7.78
	Kentucky - East	0.14	4.12	4.26
	Pennsylvania	-	2.10	2.10
	Ohio	0.05	0.20	0.25
	Virginia	-	0.91	0.91
	Maryland	0.25	0.11	0.36
	Tennessee	0.29	0.54	0.83
		1.11	15.38	16.48
Illinois Basin	Indiana	-	1.67	1.67
	Illinois	-	-	-
	Kentucky - West	-	-	-
		-	1.67	1.67
Colorado Plateau	Colorado	-	0.66	0.66
	New Mexico	0.05	0.60	0.65
	Arizona	-	0.03	0.03
	Utah	2.37	-	2.37
		2.41	1.28	3.69
Gulf Region	Texas	-	-	-
	Alabama	-	0.33	0.33
	Louisiana	-	-	-
	Mississippi	-	-	-
	Arkansas	0.00	0.07	0.07
		0.00	0.40	0.40
Other Western Interior	Oklahoma	-	0.02	0.02
	Missouri	-	-	-
	Kansas	-	-	-
		-	0.02	0.02
Northwest	Alaska	-	-	-
	Washington	-	-	-
		-	-	-
TOTAL		3.52	18.75	22.27

Step 3: Energy Losses (Btu):

The lost tons were converted into energy, by multiplying them by the typical heat content of the coals from each region (as shown in the DOE/EIA in Step 1). The corresponding losses are shown in the following table:

		ENERGY LOSSES		
		Alternative 4		
Region	States	Underground (Trillion Btu)	Surface (Trillion Btu)	Total (Trillion Btu)
N Rocky Mountain / Great Plain	Wyoming	-	-	-
	Montana	-	-	-
	North Dakota	-	-	-
		-	-	-
Appalachian Basin	West Virginia	9.08	182.30	191.38
	Kentucky - East	3.52	101.28	104.80
	Pennsylvania	-	51.55	51.55
	Ohio	1.30	4.87	6.18
	Virginia	-	22.32	22.32
	Maryland	6.23	2.63	8.86
	Tennessee	7.11	13.39	20.50
		27.24	378.34	405.57
Illinois Basin	Indiana	-	37.47	37.47
	Illinois	-	-	-
	Kentucky - West	-	-	-
		-	37.47	37.47
Colorado Plateau	Colorado	-	14.15	14.15
	New Mexico	0.99	12.86	13.85
	Arizona	-	0.54	0.54
	Utah	50.78	-	50.78
		51.77	27.55	79.32
Gulf Region	Texas	-	-	-
	Alabama	-	4.34	4.34
	Louisiana	-	-	-
	Mississippi	-	-	-
	Arkansas	0.03	0.88	0.91
		0.03	5.22	5.25
Other Western Interior	Oklahoma	-	0.52	0.52
	Missouri	-	-	-
	Kansas	-	-	-
		-	0.52	0.52
Northwest	Alaska	-	-	-
	Washington	-	-	-
		-	-	-
TOTAL		79.04	449.10	528.14

For example, the implementation of Alternative 4 in the Appalachian Region would cause the loss of 16.48 million tons of coal per year (1.11 million tons of underground coal and 15.38 million tons of surface coal). Since the typical heat content of coal from that region is 24.61 million Btu per ton, then the corresponding energy loss would be 16.48 MM ton x 24.61 MM Btu/ton = 405.57 Trillion Btu (27.24 Trillion Btu from underground coal and 378.34 Trillion Btu from surface coal).

Applying the same principle to all the regions, the final estimated nationwide impact of the application of Alternative 4 is the loss of 528.14 Trillion Btu (79.04 Trillion Btu from underground coal and 449.10 Trillion Btu from surface coal).

Step 4: Summary of Losses (tons and Btu):
The following table summarizes the losses described in steps 2 and 3.

Alternative 4

Region	Lost Production (Million Short Tons)			Lost Heat Content (Trillion Btu)
	Underground	Surface	Total	
Northern Rocky Mountains and Great Plains	-	-	-	-
Appalachian Basin	1.11	15.38	16.48	406
Illinois Basin	-	1.67	1.67	37
Colorado Plateau	2.41	1.28	3.69	79
Gulf Region	0.00	0.40	0.40	5
Other Western Interior	-	0.02	0.02	1
Northwest	-	-	-	-
Total	3.52	18.75	22.27	528

It can be observed that some mining methods and/or regions were not affected by the implementation of this Alternative (shaded in green). These are called "unaffected areas" and the production from those "unaffected areas" is called "unaffected production".
The coal necessary to make up the energy losses caused by this Alternative will come from the "unaffected areas"

Step 5: Apportioning of Make-up Energy:

As mentioned in step 4, the additional coal required to make up the energy losses will come from the unaffected areas. For this analysis, it has been considered that each unaffected area will contribute to the energy make-up, proportionally to its current production.
As observed in the following table, the Northern Rocky Mountains Region is an "unaffected area", with an "unaffected production of 63 Trillion Btu from underground mining and 9,221 Trillion Btu from Surface mining, for a regional sub-total of 9,284 Trillion Btu. Those figures are the result of multiplying the "unaffected production" (tonnage) by the typical heat content of coal coming from that region:

3.67 MM ton x 17.13 MM Btu/ton = **63 Trillion Btu** (Unaffected underground production)
538.39 MM ton x 17.13 MM Btu/ton = **9,221 Trillion Btu** (Unaffected surface production)
63 Trillion Btu + 9,221 Trillion Btu = **9,284 Btu**

As shown in the table, the total unaffected production would reach 10,766 Trillion Btu.
Since the 9,221 Trillion Btu of surface unaffected production from the Northern Rocky Mountains Region represent 85.65% of the national unaffected production (9,221 Trillion Btu ÷ 10,766 Btu = 85.65%), then it is assumed that 85.65% of the lost energy will come from that region. Similarly, since the 1,450 Btu of underground unaffected production from the Illinois Basin Region represent 13.47% of the national unaffected production, it is assumed that the same percentage of the lost energy will come from that region, and so on.

Alternative 4

	Unaffected Production (Trillion Btu)			% of Unaffected Production	
Region	Underground	Surface	Total	Underground	Surface
Northern Rocky Mountains and Great Plains	63	9,221	9,284	0.58%	85.65%
Appalachian Basin	-	-	-	0.00%	0.00%
Illinois Basin	1,450	-	1,450	13.47%	0.00%
Colorado Plateau	-	-	-	0.00%	0.00%
Gulf Region	-	-	-	0.00%	0.00%
Other Western Interior	10	-	10	0.09%	0.00%
Northwest	-	23	23	0.00%	0.21%
Total	1,523	9,244	10,766	14.14%	85.86%

In this case, 14.4% of the make-up energy will come from underground operations and the remaining 85.86% will come from surface mines.

Step 6: Apportioning of Make-up Energy (part 2:

The following table shows how the lost energy is distributed among the unaffected regions. For example, since the apportioning exercised described in step 5 indicates that 85.65% of the lost energy will come from surface operations, in the Northern Rocky Mountains Region, then additional 452 Trillion Btu will need to come from that area (528 Trillion Btu x 85.65% = 452 Trillion Btu).

Alternative 4

		% of Unaffected Production		Heat Content Contribution (Trillion Btu)		
Region	Lost Heat Content (Trillion Btu)	Underground	Surface	Underground	Surface	Total
Northern Rocky Mountains and Great Plains	-	0.58%	85.65%	3	452	455
Appalachian Basin	406	0.00%	0.00%	-	-	-
Illinois Basin	37	13.47%	0.00%	71	-	71
Colorado Plateau	79	0.00%	0.00%	-	-	-
Gulf Region	5	0.00%	0.00%	-	-	-
Other Western Interior	1	0.09%	0.00%	0	-	0
Northwest	-	0.00%	0.21%	-	1	1
Total	528	14.14%	85.86%	75	453	528

Step 7: Calculation of Required Additional Coal Production:

The following table shows the additional coal production required to make-up the calculated energy losses.

The necessary apportioned energy contribution of each region, as calculated in step 6, is divided by the typical heat content for coals form those regions, in order to calculate the necessary tons of coal.

For example, the 452 Trillion Btu from surface mines in the Northern Rocky Mountains Region that will have to be produced, represent an additional production of 26.4 Million tons (452 Trillion Btu ÷ 17.13 Million Btu = 26.4 Million tons).

The table indicates that a total of 29.9 Million tons will need to be produced at the unaffected areas, in order to compensate the calculated energy losses.

Alternative 4

	Heat Content Contribution (Trillion Btu)			Req'd. Additional Production (Million Short Tons)			
Region	Underground	Surface	Total	Underground	Surface	Total	Heat Content (Million Btu per Short Ton)
Northern Rocky Mountains and Great Plains	3	452	455	0.2	26.4	26.6	17.13
Appalachian Basin	-		-	-		-	24.61
Illinois Basin	71	-	71	3.2	-	3.2	22.44
Colorado Plateau	-	-	-	-	-	-	21.47
Gulf Region	-	-	-	-	-	-	13.15
Other Western Interior	0	-	0	0.0	-	0.0	22.74
Northwest	-	1	1	-	0.1	0.1	15.48
Total	75	453	528	3.4	26.5	29.9	

As can be observed, in order to compensate for the loss of the 22.7 Million tons (see step 4), 29.9 Million tons from unaffected areas are required.

<u>Step 8: Calculation of Required Production Increases (percentage):</u>

The following table shows the required increase of production (percentage) for each unaffected region; how much the current production of those areas would need to be increased, in order to obtain the necessary tons to make-up the estimated energy losses.
For example, as calculated in step 7, additional 0.2 Million tons of underground coal will be required to come from the Northern Rocky Mountains Region. Since the current underground production of that region is 3.67 Million tons (as indicated in the baseline data), the additional requirement represents an increase of production of 4.91% (0.2 Million tons/3.67 Million tons = 4.91%).

Alternative 4

Region	Req'd. Additional Production (Million Short Tons)			Req'd. Increase in Current Prod.	
	Underground	Surface	Total	Underground	Surface
Northern Rocky Mountains and Great Plains	0.2	26.4	26.6	4.91%	4.91%
Appalachian Basin	-	-	-	0.00%	0.00%
Illinois Basin	3.2	-	3.2	4.91%	0.00%
Colorado Plateau	-	-	-	0.00%	0.00%
Gulf Region	-	-	-	0.00%	0.00%
Other Western Interior	0.0	-	0.0	4.91%	0.00%
Northwest	-	0.1	0.1	0.00%	4.91%
Total	3.4	26.5	29.9		

Alternative 1

Region	Production (Million Short Tons)		
	Underground	Surface	Total
Northern Rocky Mountains and Great Plains	3.67	538.39	542.06
Appalachian Basin	220.23	149.38	369.61
Illinois Basin	64.61	34.27	98.88
Colorado Plateau	55.78	34.28	90.06
Gulf Region	12.28	54.10	66.38
Other Western Interior	0.44	1.50	1.94
Northwest	-	1.48	1.48
Total	357.01	813.39	1,170.40

Step 9: Calculation of Final Production Table:

The following table shows the final production distribution, reflecting the production shifts corresponding to the implementation of this alternative.
In the specific case of Alternative 4, 1,178 Million tons of coal will need to be produced in order to provide 23,470 Trillion Btu, which under the baseline conditions are achieved with 8 Million tons of coal less (1,170 Million tons under Alternative 1).

Alternative 4

	Final Production (Million Short Tons)		
Region	Underground	Surface	Total
Northern Rocky Mountains and Great Plains	4	565	569
Appalachian Basin	219	134	353
Illinois Basin	68	33	100
Colorado Plateau	53	33	86
Gulf Region	12	54	66
Other Western Interior	0	1	2
Northwest	-	2	2
Total	357	821	1,178

Appendix 3: Assumptions and Methodology Used by Morgan Worldwide in the Cost Analysis for the Proposed Rule (EIS Alternative 5)

Cost Summary

	Underground Cost / Ton	Surface Cost Per Ton	% Underground Mining
N Rocky Mountain / Great Plains	$0.253	$0.194	0.68%
Appalachian Basin	$0.758	$7.359	59.59%
Illinois Basin	$0.494	$2.934	65.34%
Colorado Plateau	$0.186	$1.049	61.93%
Gulf Region	$0.122	$2.813	18.50%
Other Western Interior	$0.218	$7.480	22.73%
Northwest	$0.000	$2.407	0.00%

Weighted Cost
$0.195
$3.426
$1.340
$0.515
$2.315
$5.829
$2.407

	Underground	
	Tons (x ,000)	%
Northern Rocky Mountains and Great Plains	4,214	0.7%
Appalachian Basin	219,862	68.4%
Illinois Basin	74,223	73.3%
Colorado Plateau	55,370	62.7%
Gulf Region	12,281	22.6%
Other Western Interior		
Northwest	0	0.0%
Total	**365,950**	

d	Surface			Total			Total Cost
Cost/Ton	Tons (x ,000)	%	Cost/Ton	Tons (x ,000)	Weighted Cost		
$0.253	618,499	99.3%	$0.194	622,713	$0.19		$121,331,210
$0.758	101,500	31.6%	$7.359	321,362	$2.84		$913,723,080
$0.494	27,000	26.7%	$2.934	101,223	$1.15		$115,920,773
$0.186	33,000	37.3%	$1.049	88,370	$0.51		$44,932,193
$0.122	42,000	77.4%	$2.813	54,281	$2.20		$119,623,175
							$0
$0.000	1,000	100.0%	$2.407	1,000	$2.41		$2,407,211
	822,999			**1,188,949**	**$1.11**		**$1,317,937,641**

Cost Impacts - Surface

	Element #1	Element #2
	Stream Definition	Baseline Data
N Rocky Mountain / Great Plains		$0.003
Appalachian Basin		$0.188
Illinois Basin		$0.040
Colorado Plateau		$0.009
Gulf Region		$0.099
Other Western Interior		$0.515
Northwest		$0.068

Notes:

Annual Surface Tons

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Baseline Data

Additional monitoring prior to permit sub
Tons per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Mc

Material Damage

Additional risk of long term treatment / a

Long term treatment / abatement occurre

Treatment Cost as % of bond amount per
Average full cost bonding amount
Acres per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Bo

Activity in or Near streams

Additional cost for stream / buffer zone r
Stream length per ton of coal varies by re
Effect of fills

Appalachian Basin
Effected by mining (excl Mine Through a

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest
Average permit life

Annual cost per Ton calculated as: (Str

Mining Through Streams

Additional cost for stream restoration
Stream length per ton of coal varies by re
Effect of Mine through

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest
Average permit life

Annual cost per Ton calculated as: (Str

Monitoring

Additional monitoring during mining is a
Tons per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Mo

Surface Configuration / Fills

Additional excess spoil transportation in
Additional cost assumed at $0.25 per cu.y

Appalachian Basin

Annual cost per Ton calculated as: (Cu

AOC Exception

Increased bonding if AOC variance
AOC variances differ by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Revegetation Topsoil

Increased reclamation cost
Cost increase varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi

Northwest

Annual cost per Ton calculated as: (Pe

Fish & Wildlife

Increased enhancement cost
Costs vary by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Pe

Performance Bond Release

Additional time for bond releases
Time extension assumed at 3 years
Average bonding amount
Acres per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Cost of bond 1%

Annual cost per Ton calculated as: (Pe

Financial Assurance for Long Term Discharge

Additional Bonding
Additional bonding amount
Acres per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Cost of bond 1%

Annual cost per Ton calculated as: (Pe

Element #3	Element #4	Element #5	Element #6	Element #7
Material Damage	Activity in or Near Stream	Mining Through Stream	Monitoring	Surface Confguration and Fills
$0.006	$0.005	$0.005	$0.001	
$0.445	$0.268	$0.148	$0.094	$3.500
$0.446	$0.223	$0.223	$0.020	
$0.209	$0.122	$0.122	$0.005	
$0.455	$0.284	$0.284	$0.050	
$1.232	$0.514	$0.514	$0.258	
$0.297	$0.346	$0.346	$0.034	

Great Plains	538,387,000
	149,376,000
	34,266,000
	34,283,000
	54,099,000
or	1,499,000
	1,477,000

mittal cost is assumed at $0.5M per permit

Great Plains	193.6	M tons
	2.7	M tons
	12.6	M tons
	55.2	M tons
	5.0	M tons
or	1.0	M tons
	7.4	M tons

nitoring Cost) / (Tons per Permit)

ibatement

nce as % of permits

	5%
annum	20%
	$6,000

Great Plains	562,200
	1,107,160
	254,880
	119,690
	409,920
or	30,790
	7,300

nding Amount per Acre) x (Treatment cost %) x (Damage %) x (Acreage) / (Annual Tons)

estoration
gion

	Excess Spoil per Ton cu.yd/ton	Yd of Exces Spoil per Ft cu.yd / ft	Stream Impact per Ton ft	Cost per Foot
	3	5,000	0.001	$200

nd Fill)

	Intermittent / Perennial Ft per Acre	Acre per Permit	Stream Length per permit	% Effected
Great Plains	5	562,200	2,811,000	10%
	20	1,107,160	22,143,200	10%
	15	254,880	3,823,200	20%
	10	119,690	1,196,900	35%
	15	409,920	6,148,800	25%
or	10	30,790	307,900	25%
	20	7,300	146,000	35%
	10	years		

eam Length) x (% Mined Through) x (Cost per Foot) / (Annual Tons) x (Permit Life)

gion

	Intermittent / Perenial Ft per permit acre	Acre per Permit	Stream Length per permit	% Mined Through
Great Plains	5	562,200	2,811,000	60%
	20	1,107,160	22,143,200	35%
	15	254,880	3,823,200	75%
	10	119,690	1,196,900	50%
	15	409,920	6,148,800	65%
or	10	30,790	307,900	65%
	20	7,300	146,000	50%
	10	years		

eam Length) x (% Mined Through) x (Cost per Foot) / (Annual Tons) x (Permit Life)

ssumed at $0.25M per permit per annum

Great Plains	193.6	M tons
	2.7	M tons
	12.6	M tons
	55.2	M tons
	5.0	M tons
or	1.0	M tons
	7.4	M tons

onitoring Cost) / (Tons per Permit)

order to elevate backfill and achieve AOC plus landforming
/d. Additional cost is only for trucking

	Average Ratio cu.yd/ton
	14

bic Yards Moved) x (Additional Cost per Cubic Yard)

	AOC Variance % of Permits
Great Plains	
or	

	Addition $ per acre
Great Plains	$1,000
	$2,000
	$1,500
	$1,000
	$1,000
or	$1,000

	$1,500

rmitted Acres) x (Additional Cost per Acre) / (Annual Tons) x (Permit Life)

	Addition $ per acre
Great Plains	$500
	$1,500
	$1,000
	$500
	$1,000
or	$1,000
	$1,000

rmitted Acres) x (Additional Cost per Acre) / (Annual Tons) x (Permit Life)

	$3,000
Great Plains	562,200
	1,107,160
	254,880
	119,690
	409,920
or	30,790
	7,300
of value	

rmitted Acres) x (Average Bond) x (Bonding Cost) x 3 / (Annual Tons) x (Permit Life)

	$2,500
Great Plains	562,200
	1,107,160
	254,880
	119,690
	409,920
or	30,790
	7,300
of value	

rmitted Acres) x (Additional Bond) x (Bonding Cost) / (Annual Tons) x (Permit Life)

Element #8	Element #9	Element #10	Element #11	Element #12
AOC Exceptions	Revegetation / Topsoil	Fish & Wildlife	Performance Bond / Release	Financial Assurance for Long Term Discharges
	$0.104	$0.052	$0.009	$0.008
	$1.482	$1.112	$0.067	$0.056
	$1.116	$0.744	$0.067	$0.056
	$0.349	$0.175	$0.031	$0.026
	$0.758	$0.758	$0.068	$0.057
	$2.054	$2.054	$0.185	$0.154
	$0.741	$0.494	$0.044	$0.037

Cost per Ton

$0.12

Cost per Foot	Cost per Permit
$100	$28,110,000
$100	$221,432,000
$100	$76,464,000
$100	$41,891,500
$100	$153,720,000
$100	$7,697,500
$100	$5,110,000

Cost per Foot	Cost per Permit
$200	$337,320,000
$200	$1,550,024,000
$200	$573,480,000
$200	$119,690,000
$200	$799,344,000
$200	$40,027,000
$200	$14,600,000

Element #13	TOTAL
Permit Coordination	
	$0.194
	$7.359
	$2.934
	$1.049
	$2.813
	$7.480
	$2.407

Report No: DOE/EIA 0584 (2008)
Data For: 2008
Report Released: September 2009

Region	Coal-Producing	# of Underground Mines	Underground	# of Surface Mines	Surface	Production	% Underground	Subtotal	% of Total	Cum %	% Underground
N Rocky Mountain / Great Plains	Wyoming	1	3,501	19	464,143	467,644	0.7%				
	Montana	1	168	5	44,617	44,785	0.4%				
	North Dakota			4	29,627	29,627	0.0%	542,056	46.3%	46.3%	0.7%
Appalachian Basin	West Virginia	186	88,369	115	69,409	157,778	56.0%				
	Kentucky - East	205	44,143	241	46,116	90,259	48.9%				
	Pennsylvania	51	53,318	215	12,095	65,413	81.5%				
	Ohio	11	17,053	37	9,198	26,251	65.0%				
	Virginia	65	15,806	49	8,907	24,713	64.0%				
	Maryland	2	753	19	2,107	2,860	26.3%				
	Tennessee	5	789	18	1,544	2,333	33.8%	369,607	31.6%	77.9%	59.6%
Illinois Basin	Indiana	6	12,223	24	23,670	35,893	34.1%				
	Illinois	11	27,055	8	5,863	32,918	82.2%				
	Kentucky - West	11	25,331	12	4,733	30,064	84.3%	98,875	8.4%	86.3%	65.3%
Colorado Plateau	Colorado	8	24,370	4	7,659	32,029	76.1%				
	New Mexico	1	7,046	4	18,599	25,645	27.5%				
	Arizona			1	8,025	8,025	0.0%				
	Utah	9	24,365			24,365	100.0%	90,064	7.7%	94.0%	61.9%
Gulf Region	Texas	0		11	39,017	39,017	0.0%				
	Alabama	8	12,281	51	8,330	20,611	59.6%				
	Louisiana			2	3,843	3,843	0.0%				
	Mississippi			1	2,842	2,842	0.0%				
	Arkansas	1	2	1	67	69	2.9%	66,382	5.7%	99.7%	18.5%
Other Western Interior	Oklahoma	1	441	6	1,023	1,464	30.1%				
	Missouri			2	247	247	0.0%				
	Kansas			2	229	229	0.0%	1,940	0.2%	99.9%	22.7%
Northwest	Alaska			1	1,477	1,477	0.0%				
	Washington					0		1,477	0.1%	100.0%	0.0%
TOTAL			**357,014**		**813,387**	**1,170,401**	**30.5%**				

Surface				Underground			
Tons per Mine per Annum	Permit Life	Tons per Permit	Weighted Average	Tons per Mine per Annum	Permit Life	Tons per Permit	Weighted Average
24,613	10	246,128		3,501	15	52,515	
8,957	10	89,570		168	15	2,520	
7,407	10	74,068	**193,591**		15	0	**27,518**
1,372	5	6,860		475	10	4,751	
375	5	1,873		215	10	2,153	
304	5	1,521		1,045	10	10,455	
709	5	3,547		1,550	10	15,503	
504	5	2,522		243	10	2,432	
151	5	753		377	10	3,765	
130	5	648	**2,663**	158	10	1,578	**4,195**
1,496	5	7,478		2,037	15	30,558	
4,115	5	20,574		2,460	15	36,893	
2,505	7	17,537	**12,602**	2,303	15	34,542	**34,612**
8,007	5	40,036		3,046	15	45,694	
6,411	10	64,113		7,046	15	105,690	
8,025	10	80,250			15	0	
			55,205	2,707	15	40,608	**46,484**
3,547	5	17,735			10	0	
404	5	2,021		1,535	10	15,351	
1,922	5	9,608			10	0	
2,842	5	14,210			10	0	
69	5	345	**5,029**	2	10	20	**13,648**
244	5	1,220		441	10	4,410	
124	5	618			10	0	
115	5	573	**970**		10	0	**4,410**
1,477	5	7,385			10	0	
			7,385		10		

		Permitted Acreage		Subtotal	
Region	State	Surface	Underground	Surface	Underground
N Rocky	Wyo	395,840	5,270		
	Mont	59,900	6,400		
	N. Dak	106,460	0	562,200	11,670
App. Basin	WV	269,950	31,160		
	Ky - East	436,230	933,450		
	Pa	295,800	47,700		
	Oh	9,120	590		
	Virg	64,560	7,440		
	Mary	4,150	940		
	Tenn	27,350	1,270	1,107,160	1,022,550
Illinois Bas	Ind	194,710	7,480		
	Ill	11,700	22,600		
	Ky-West	48,470	400,050	254,880	430,130
Col. Plateau	Col	45,100	118,800		
	NM	74,150	13,220		
	Ariz				
	Ut	440	1,790	119,690	133,810
Gulf Reg.	Tx	285,600	0		
	Al	75,370	11,460		
	LA	41,930	0		
	Miss	5,800	0		
	Ark	1,220	120	409,920	11,580
Other West	Ok	21,600	300		
	Missouri	6,050	0		
	Kan	3,140	0	30,790	300
Northwest	Alaska	7,300	1,250		
	Wash		0	7,300	1,250

Assumed 90% of surface in E Ky. 70 % of underground

Assumed 10% of surface in W Ky. 30 % of underground

No information thru 2000

used 2010 report - no infor for 2009
used 2010 report - no infor for 2009
used 2010 report - no infor for 2009

14,820 ac.Excluded as no 2008 onward production

Cost Impacts - Surface

	Element #1	Element #2	Element #3	Element #4	Element #5	Element #6	Element #7	Element #8	Element #9	Element #10	Element #11	Element #12	Element #13
	Stream Definition	Baseline Data	Material Damage	Activity in or Near Stream	Mining Through Stream	Monitoring	Surface Confguration and Fills	AOC Exceptions	Revegetation / Topsoil	Fish & Wildlife	Performance Bond / Release	Financial Assurance for Long Term Discharges	Permit Coordination
	current definitions expanded to consider biological, hydrological, and physical characteristics.	*expanding suite of chemicals subject to analysis, documentation of biological conditions, sediment load, meteorological data, stream form and function, and aquatic organisms*	*when the mining operation has affected the quality or quantity of the water so that the water body could no longer be used for its designated use*	*prohibit mining activities in intermittent and perennial streams and within 100 feet of intermittent and perennial streams, but would allow excess spoil fills*	*mining through intermittent and perennial streams prohibited unless the restoration of stream form and function could be demonstrated*	*expanding the suite of chemicals subject to analysis and requiring documentation of biological conditions*	*greater emphasis on minimizing the amount of excess spoil disposed of in valley fills additional regulation the placement of excess spoil / restoring pre-mining topography*	*allows AOC exceptions, but imposes additional requirements / criteria to ensure protection of streams, aquatic ecology, and biologic communities*	*revegetation requirements that emphasize native species and original organic material*	*ephemeral streams not included. Enhancement activities, as conditions of the permit, must be within the same watershed and on the permitted area*			
N Rocky Mountain / Great Plains		Increased cost for additional data collection				Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Appalachian Basin	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release	Additional cost for avoidance and additional restoration cost	Additional cost for avoidance and additional restoration cost	Increased cost for additional data collection	Increased cost for higher excess spoil transport	Increased cost for stream protection	Increased cost for topsoil and planting	Increased on site mitigation cost	Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Illinois Basin	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release	Additional cost for avoidance and additional restoration cost	Additional cost for avoidance and additional restoration cost	Increased cost for additional data collection			Increased cost for topsoil and planting	Increased on site mitigation cost	Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Colorado Plateau		Increased cost for additional data collection				Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Gulf Region	Additional stream segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release	Additional cost for avoidance and additional restoration cost	Additional cost for avoidance and additional restoration cost	Increased cost for additional data collection			Increased cost for topsoil and planting	Increased on site mitigation cost	Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Other Western Interior	Additional stream segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release	Additional cost for avoidance and additional restoration cost	Additional cost for avoidance and additional restoration cost	Increased cost for additional data collection			Increased cost for topsoil and planting	Increased on site mitigation cost	Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	
Northwest	Additional stream segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release	Additional cost for avoidance and additional restoration cost	Additional cost for avoidance and additional restoration cost	Increased cost for additional data collection			Increased cost for topsoil and planting	Increased on site mitigation cost	Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranne and length of coverage	

Cost Impacts - Underground

	Element #1	Element #2	Element #3	Element #4	Element #5	Element #6	Element #7	Element #8	Element #9	Element #10	Element #11	Element #12	Element #13
	Stream Definition	Baseline Data	Material Damage	Activity in or Near Stream	Mining Through Stream	Monitoring	Surface Confguration and Fills	AOC Exceptions	Revegetation / Topsoil	Fish & Wildlife	Performance Bond / Release	Financial Assurance for Long Term Discharges	Permit Coordination
	current definitions expanded to consider biological, hydrological, and physical characteristics.	*expanding suite of chemicals subject to analysis, documentation of biological conditions, sediment load, meteorological data, stream form and function, and aquatic organisms*	*when the mining operation has affected the quality or quantity of the water so that the water body could no longer be used for its designated use*	*prohibit mining activities in intermittent and perennial streams and within 100 feet of intermittent and perennial streams, but would allow excess spoil fills*	*mining through intermittent and perennial streams prohibited unless the restoration of stream form and function could be demonstrated*	*expanding the suite of chemicals subject to analysis and requiring documentation of biological conditions*	*greater emphasis on minimizing the amount of excess spoil disposed of in valley fills additional regulation the placement of excess spoil / restoring pre-mining topography*	*allows AOC exceptions, but imposes additional requirements / criteria to ensure protection of streams, aquatic ecology, and biologic communities*	*revegetation requirements that emphasize native species and original organic material*	*ephemeral streams not included. Enhancement activities, as conditions of the permit, must be within the same watershed and on the permitted area*			
N Rocky Mountain / Great Plains		Increased cost for additional data collection				Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Appalachian Basin	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection	Increased cost for esces spoil disposal for mine face up and refuse disposal				Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Illinois Basin	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Colorado Plateau		Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Gulf Region	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Other Western Interior	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	
Northwest	Additional streamn segments could be classified as intermittent	Increased cost for additional data collection	More difficulty in obtaining bond release. Cost for stream restoration fom subsidence damage			Increased cost for additional data collection					Increased cost due to length of bond coverage	Increased Cost due to additional financial assuranrnce and length of coverage	

Cost Impacts - Underground

	Element #1	Element #2
	Stream Definition	Baseline Data
N Rocky Mountain / Great Plains		$0.018
Appalachian Basin		$0.119
Illinois Basin		$0.014
Colorado Plateau		$0.011
Gulf Region		$0.037
Other Western Interior		$0.113
Northwest		

Notes:

Annual Underground Tons

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Baseline Data

Additional monitoring prior to permit sub
Tons per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Mc

Material Damage

Additional risk of long term treatment / a
Long term treatment / abatement occurrer
Treatment Cost as % of bond amount per
Average bonding amount
Acres per permit varies by region

N Rocky Mountain /
Appalachian Basin

Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Bo

Monitoring

Additional monitoring during mining is a
Tons per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Annual cost per Ton calculated as: (Mo

Surface Configuration / Fills

Additional excess spoil transportation and
Additional cost assumed at $0.50 per cu.y

Appalachian Basin

Annual cost per Ton calculated as: (Cu

Performance Bond Release

Additional time for bond releases
Time extension assumed at 3 years
Average bonding amount
Acres per permit varies by region

N Rocky Mountain /
Appalachian Basin
Illinois Basin
Colorado Plateau
Gulf Region
Other Western Interi
Northwest

Cost of bond	1%
Permit Life	15

Annual cost per Ton calculated as: (Pe

Financial Assurance for Long Term Discharge

Additional Bonding

Average bonding amount		
Acres per permit varies by region		
	N Rocky Mountain /	
	Appalachian Basin	
	Illinois Basin	
	Colorado Plateau	
	Gulf Region	
	Other Western Interi	
	Northwest	
Cost of bond		1%
Permit Life		15

Element #3	Element #4	Element #5	Element #6	Element #7
Material Damage	Activity in or Near Stream	Mining Through Stream	Monitoring	Surface Confguration and Fills
$0.191			$0.009	
$0.279			$0.060	$0.250
$0.399			$0.007	
$0.144			$0.005	
$0.057			$0.018	
$0.041			$0.057	

Great Plains	3,669,000
	220,231,000
	64,609,000
	55,781,000
	12,283,000
or	441,000
	0

mittal cost is assumed at $0.5M per permit

Great Plains	27.5	M tons
	4.2	M tons
	34.6	M tons
	46.5	M tons
	13.6	M tons
or	4.4	M tons
	0.0	M tons

nitoring Cost) / (Tons per Permit)

batement	
nce as % of permits	10%
annum	20%
	$3,000
Great Plains	11,670
	1,022,550

	430,130
	133,810
	11,580
.or	300
	1,250

nding Amount per Acre) x (Treatment cost %) x (Damage %) x (Acreage) / (Annual Tons)

ssumed at $0.25M per permit per annum

' Great Plains	27.5	M tons
	4.2	M tons
	34.6	M tons
	46.5	M tons
	13.6	M tons
.or	4.4	M tons
	0.0	M tons

onitoring Cost) / (Tons per Permit)

d coal preparation plant waste disposal
/d. Additional cost is only for trucking

	Waste per ton
	cu.yd/ton
	0.5

ubic Yards Moved) x (Additional Cost per Cubic Yard)

	$3,000
' Great Plains	11,670
	1,022,550
	430,130
	133,810
	11,580
.or	300
	1,250

of value
years

rmitted Acres) x (Average Bond) x (Bonding Cost) x 3 / (Annual Tons) x (Permit Life)

	$2,500
Great Plains	11,670
	1,022,550
	430,130
	133,810
	11,580
or	300
	1,250
of value	
years	

Element #8	Element #9	Element #10	Element #11	Element #12
AOC Exceptions	Revegetation / Topsoil	Fish & Wildlife	Performance Bond / Release	Financial Assurance for Long Term Discharges
			$0.019	$0.016
			$0.028	$0.023
			$0.040	$0.033
			$0.014	$0.012
			$0.006	$0.005
			$0.004	$0.003

Element #13	TOTAL
Permit Coordination	
	$0.253
	$0.758
	$0.494
	$0.186
	$0.122
	$0.218
	$0.000