Coal supply and cost under technological and environmental uncertainty

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I did not complete this work alone. I had a lot of help along the way.

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Abstract

This thesis estimates available coal resources, recoverability, mining costs, environmental impacts, and environmental control costs for the United States under technological and environmental uncertainty. It argues for a comprehensive, well-planned research program that will resolve resource uncertainty, and innovate new technologies to improve recovery and environmental performance. A stochastic process and cost (constant 2005$) model for longwall, continuous, and surface mines based on current technology and mining practice data was constructed. It estimates production and cost ranges within 5 – 11 percent of 2006 prices and production rates. The model was applied to the National Coal Resource Assessment. Assuming the cheapest mining method is chosen to extract coal, 250 – 320 billion tons are recoverable. Two-thirds to all coal resource can be mined at a cost less than $4/mmBTU. If U.S. coal demand substantially increases, as projected by alternate Energy Information Administration (EIA), resources might not last more than 100 years. By scheduling cost to meet EIA projected demand, estimated cost uncertainty increases over time. It costs less than $15/ton to mine in the first 10 years of a 100 year time period, $10-$30/ton in the following 50 years, and $15-$90/ton thereafter.

Environmental impacts assessed are subsidence from underground mines, surface mine pit area, erosion, acid mine drainage, air pollutant and methane emissions. The analysis reveals that environmental impacts are significant and increasing as coal demand increases. Control technologies recommended to reduce these impacts are backfilling underground mines, surface pit reclamation, substitution of robotic underground mining systems for surface pit mining, soil replacement for erosion, placing barriers between exposed coal and the elements to avoid acid formation, and coalbed methane development to avoid methane emissions during mining. The costs to apply these technologies to meet more stringent environmental regulation scenarios are estimated. The results show that the cost of meeting these regulatory scenarios could increase mining costs two to six times the business as usual cost, which could significantly affect the cost of coal-powered electricity generation.

This thesis provides a first estimate of resource availability, mining cost, and environmental impact assessment and cost analysis. Available resource is not completely reported, so the available estimate is lower than actual resource. Mining costs are optimized, so provide a low estimate of potential costs. Environmental impact estimates are on the high end of potential impact that may be incurred because it is assumed that impact is unavoidable. Control costs vary. Estimated cost to control subsidence and surface mine pit impacts are suitable estimates of the cost to reduce land impacts. Erosion control and robotic mining system costs are lower, and methane and acid mine drainage control costs are higher, than they may be in the case that these impacts must be reduced.

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Chapter 1: Introduction

Coal is considered an abundant and inexpensive fuel. It is widely accepted and stated that the U.S. has 250 years worth of coal. This perception is based on the assumption that coal resources are accessible and easy to extract; the 250-year "estimate was made in the 1970s and was based on the assumption that 25 percent of the coal that had been located was recoverable with current technology and at current prices" [1]. Optimistically, if more coal is located, coal availability will increase. In the absence of finding additional coal resource, the 250-year estimate is inappropriate because it assumes that all coal resource is equal and recoverable by 1970s technology with minimal safety or environmental hazard. However, future mining will likely raise new operational challenges. Coal seams vary in depth and thickness. Thick seams offer the greatest profit because they can yield a lot of product if mined. Shallow seams are also profitable to mine because little time and money must be expended to remove overlying material to surface mine it or dig access shafts to underground mine it. As shallow and thick seams are depleted, thin and deep seams must be mined to meet coal demand. Although extractive technology has evolved somewhat since the 1970s, it is not be able to produce coal from these more marginal seams at affordable costs.

This dissertation constructs a model to simulate current mining systems and applies it to the National Coal Resource Assessment (NCRA) to provide insight into future coal recoverability and mining cost. The NCRA is the best estimate of U.S. coal resources, and reports coal available by thickness and depth throughout currently mined coal regions. As a result of this analysis, cost curves illustrating coal region and mine technology selection to meet projected demand are assembled. The Energy Information Administration's business as usual case is examined, as well as alternate forecasts that account for limited natural gas supply, fossil technology innovation and integrated technology development.

Although these cost curves provide insight into future coal mining cost to meet demand, they do not completely represent the total cost of coal mining. The environmental costs associated with coal mining are considerable, and these costs can be expected to increase.

A recent National Academy of Science (NAS) report found that as remaining resources are thinner and deeper than currently mined resources, continued mining will aggravate environmental and safety problems as well as create new ones [2].

This thesis adds detail and insight to the analysis performed in the NAS report. It comes to some of the same conclusions as the NAS report – coal resource availability is uncertain; technology must be developed to improve recovery based on geological characteristics of coal; environmental implications of mining coal must be better understood. This analysis does not look at worker health and safety, which is addressed in the NAS report. This thesis makes several contributions towards improving our understanding of coal resource availability, coal recovery, and mining environmental impact. This thesis discusses how current coal resource data can be used to estimate available resource, and an estimate of coal resource given the data uncertainty. This thesis also estimates cost to extract coal using current technology, given the uncertainty in coal resource geology, and operation configuration and cost. The results are underground or surface mine cost and recovery estimates throughout the country, which are then used to produce cost curves and evaluate whether Energy Information Administration (EIA) projected demand can be met by recoverable coal resources. Finally, this thesis discusses available methods to estimate and reduce environmental impact from mining coal. It uses current estimation methods to provide insight into the magnitude of environmental impact that will result from mining coal to meet demand. It also reports on technologies that could be adopted from other countries or other industries to reduce these impacts, and estimates the cost to implement these tools.

Mining is an invasive process, which permanently transforms the environment. Traditionally, mining land and water impacts are regulated because they are the most visible. Underground mining can cause subsidence, which causes the overlying ground to collapse. When the ground collapses surface structures, such as buildings, roads, and railways, can be damaged. Subsidence can also disrupt overlying water supplies. Surface mining rearranges land topography. Overburden, or material overlying a seam, is replaced in surface mining pits. However, the original contour of the land may not be recovered if the surface mine was located in steep terrain. Overburden management poses additional problems in steep mining regions. In mountainous regions it is often placed in valleys, where it interrupts surface water bodies. The contentious practice of placing mountain top overburden in surrounding valleys is known as "mountain top removal" and is used in Appalachia because it is a high yielding low cost method. Mining can also acidify ground and surface water, because coal exposed during and after the mining process can mix with air and water to create acid. This acid can leach into local water supplies, making it unfit for consumption or recreation.

Environmental regulations that currently apply, or could be expanded to apply, to mining are the Surface Mine Control and Reclamation Act (SMCRA), Clean Water Act (CWA), and Clean Air Act (CAA). The CAA currently exempts air pollution from coal mining. The CWA and SMCRA are leniently applied and enforced. However, there is potential to improve environmental performance through regulation. This dissertation examines coal mining costs under two scenarios; laissez faire environmental regulation and regulation that has been revised to reflect modern environmental concerns. The result is insight into the cost to improve mine coal environmental performance and technological suggestions to mitigate expected environmental problems from current and future mining practices.

Chapter 2 develops and validates a model that estimates mining costs under the current SMCRA. The model represents typical U.S. continuous mines, longwall mines, and truck and shovel surface mines. It considers a range of possible equipment configurations within a range of input geological conditions. It simulates average production and average cost. The cost includes assumes that reclamation costs, to fill and revegetate surface voids after mining, are equal to bonding costs. This assumption is consistent with current SMCRA enforcement. The model is validated by simulating 41 real U.S. mines. The model estimated of production and cost ranges within 5 – 11 percent of historic prices and production rates.

Chapter 3 applies the model to the NCRA. The NCRA summarizes the location, overburden depth, seam thickness, and coal quality of coalfields in the Colorado Plateau, Rocky Mountains and Great Plains, Northern and Central Appalachia, Illinois, and Gulf Coast basins. The NCRA coalfield depth and thickness are input into the model to estimate the cost of coal mining. The estimated median costs range from $8/ton to $30/ton in the most of the Colorado Plateau and Rocky Mountains and Great Plains coalfields, from $33/ton to $55/ton in Appalachia, and $76 to $80/ton in the Illinois basin. The results show that 250 – 320 billion tons can be recovered by using current mining methods. The analysis concluded that this might be insufficient to meet coal demand if demand increases faster than the business as usual rate, by stagnating electricity generation technology at 2008 levels or substituting coal for liquid fuels, over a 100-year period.

Chapter 4 proposes environmental regulation revisions and revises mining costs. It evaluates two scenarios, (1) more stringent SMCRA application and enforcement, (2) more stringent SMCRA and CWA application and enforcement, and expanding the CAA to regulate coal mining. Environmental impact and cost evaluation are added to the model. Subsidence from underground mines, mountain top removal, water acidification, soil erosion, air quality, and greenhouse gas emissions are examined. The chapter estimates prevention costs: backfilling to prevent underground mine subsidence; robotic underground mining to avoid mountain top removal; coating exposed coal faces with sealant, grout or liners to reduce potential acid generation; soil replacement costs to mitigate erosion; methane well development and operation costs to extract methane before and during mining. The proposed stringent environmental regulation scenarios maintain the bonding requirement, as insurance that reclamation will be completed. However, it also mandates *prevention* of subsidence, surface stream fill, topography disruption, acid mine drainage, erosion, methane and dust emissions. Inclusion of these environmental costs double or quadruple underground mining costs, and increases surface mining costs by 30 – 50 percent.

References

1. Wald, M.L., *Science Panel Finds Fault with Estimates of Coal Supply*, in *New York Times*. 2007: New York City.
2. National Academy of Sciences, *Coal: Research and Development to Support National Energy Policy*. 2007, Washington D.C.: National Science Foundation.

Chapter 2: Coal mining production and cost model construction and validation

1 Introduction

Current coal cost forecasts extrapolate historic mine cost statistics. This practice assumes that geological, operational and regulatory mining conditions will remain the same in the future. However, historical extraction costs are not indicative of future mining costs, for several reasons. Mining practices are subject to change. Fuel, equipment capital and operating costs, and environmental regulation may increase or decrease; labor practices and technology choices may change. A flexible model of mining processes can provide insight into resource development decisions. Such a model can be adjusted to examine mining costs under uncertain future conditions, whether thinner or deeper seams, stringent regulation, or new technology adoption, and can approximate future cost to mine coal based on assumptions about geology, technology and environmental policy.

Process based modeling is a tool to estimate mine production and cost, based on technology choices, unit operations and costs. The stochastic model described in this chapter can account for this operational uncertainty. It considers a range of possible equipment configurations within a range of geological conditions for a given mine, and outputting a range of likely costs and production rates. The stochastic results represent a wide range of possibilities. This model considers geological conditions only, and is independent of delays that may be inherent due to operator preferences and site-specific problems such as labor problems or challenging terrain. It can estimate surface and underground mining costs in a new resource; the least cost means can then be chosen, thus optimizing resource planning. Furthermore, the model may be adjusted to estimate future system efficiencies because it simulates coal extraction systems. Unit operation efficiencies can be adjusted according to expected technological improvements or regulatory constraints, to determine changes to production and cost. The benefit of a process-based model is two-fold; optimize resource development for lowest cost and greatest production, and evaluate new technologies and regulations if performance and cost data are known.

This chapter describes a probabilistic model of mining processes and costs for U.S. surface and underground (continuous mining and longwall mining) operations. The model calculates costs (constant 2005$) that are representative of the average mining practice. It can be used to optimize resource planning, estimates cost by each mining method. The most desirable method, whether based on least cost or other criteria, can be chosen. The first half of the chapter describes the model's assumptions and mine production and cost calculations. The second half describes its validation.

2 Background

2.1 Surface Mining

Surface mining involves a series of material breaking and moving processes. The surface mine equipment configuration assumed in the model, and described here, uses a hydraulic shovel and truck operation. First, land is cleared and prepared for mining. Next, holes are drilled into the strata overlying the coal, called "overburden". Explosives are dropped into the holes to break up the overburden. The crumbled overburden is then excavated to expose the coal. The coal is broken up by hydraulic excavators and removed by truck. The overburden from the pits, commonly referred to as spoil, is placed in previously mined pits. Excess spoil is placed into surface storage or impoundments. The amount of material – overburden or coal – is dependent on pit size.

2.2 Underground Continuous Mining

Continuous mining uses several unit operations to cut, load, and remove coal from an underground mine. This method is also called "room and pillar mining" because "rooms" of coal are extracted while "pillars" are left to support the overburden, or "roof". It consists of cutting the coal with a continuous miner, loading the coal and securing the roof with long steel rods called "bolts". While the continuous miner cuts the coal, it intermittently loads the coal onto shuttle cars. The shuttle car then carries the coal to a central pick up point for transport to the surface. The coal is transferred from the collection point to the surface by conveyor belt. After the continuous miner has cut the coal, it backs out of the cut room. The roof bolter then enters and secures the roof by shooting bolts into the overlying strata. All the while, electricity, water, and ventilation systems must be steadily expanded and maintained in order to support the mine and miner's operations underground.

2.3 Underground longwall mining

Longwall mining is a high extraction method. The sequence of mining in a longwall mine begins with "development" sections mined by the continuous mining method. A diagram of how a longwall mine is laid out is drawn in Figure 1. The ventilation air flows from the main entries to the "bleeder entries", which eliminates methane build up in the broken material known as "gob" that forms as the longwall panel is mined. The "bleeder entries" are behind the longwall panel, and are shown on the left in Figure 1. Two parallel development sections must be completed in order to support a longwall, so that equipment may be supplied and removed from the longwall along its entire length (LW_L). It is assumed that when the longwall panel begins operation, additional development sections may begin in order to support future longwall panels. These development sections are mined in the same manner as a continuous mine, except that the pillars, referred to as "chain pillars", have a constant width and length of 82' and 160', respectively, at any depth [11]. The coal extracted in the development sections is transported within the mine by shuttle cars, as it is in the previously described continuous mine system. Coal is cut in the longwall panel by a "longwall shearer" that slices the coal by passing back and forth along the "face" or longwall width (LW_W). Coal mined by the longwall shearer is collected and moved by the face conveyor and stage loader to a belt conveyor. The strata overlying the shearer is supported by "shields." The shearer, conveyor and shields progress together underground.

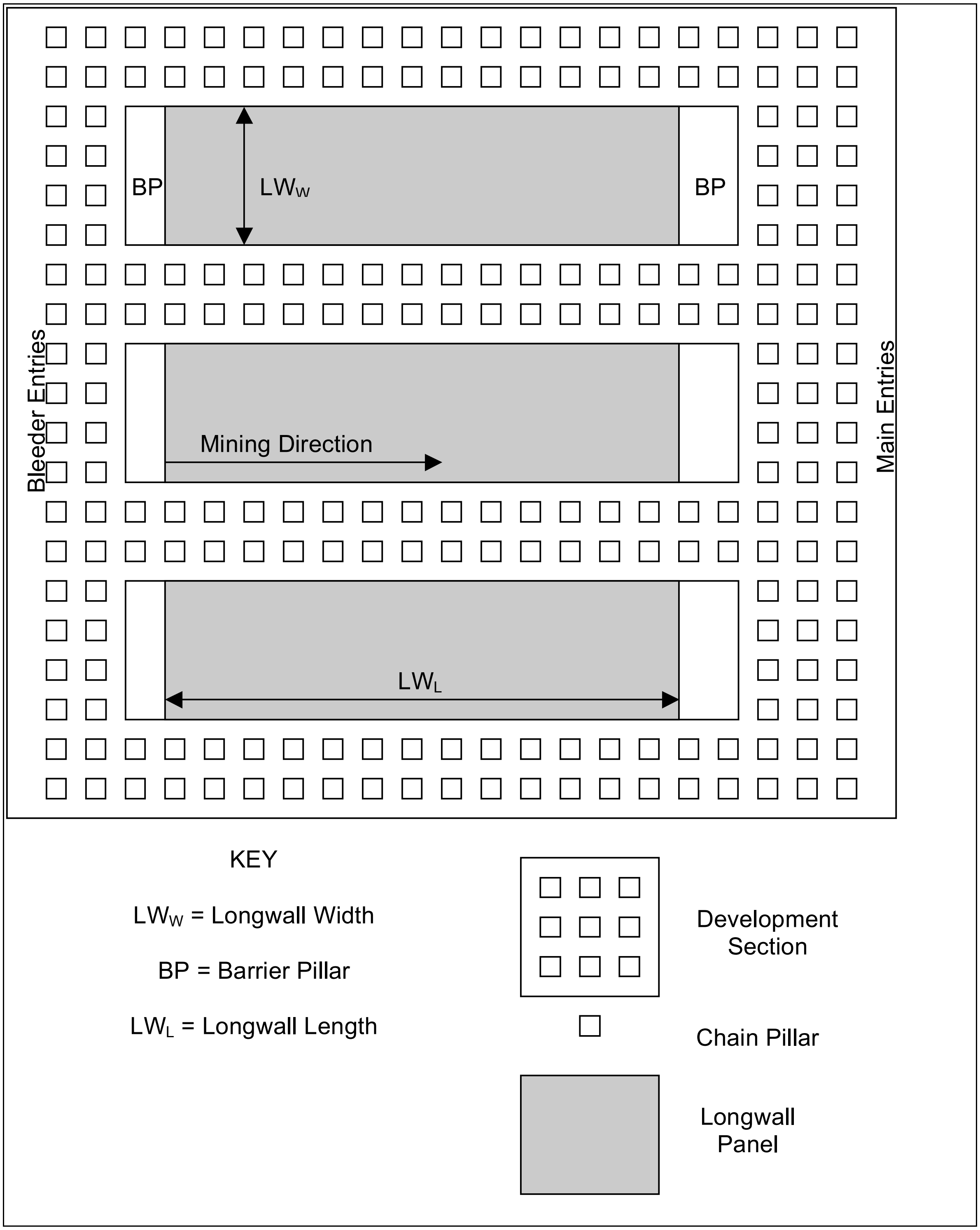

Figure 1. Longwall Mine Plan View

2.4 CoalVal Comparison

Process based modeling is typically site specific. The Bureau of Mines created the CoalVal model as a PC based tool to estimate the cost to open a greenfield mine. When the Bureau was dismantled in 1996, the CoalVal work became the responsibility of the USGS. The last publicly available user's manual was published in 1994, for CoalVal 2.0. The model is a financial model to estimate costs of mining coal via auger, contour strip, mountain top removal, continuous miner, longwall, dragline, and truck and shovel methods. It estimates the cost to extract coal, based on user equipment and labor selection. It estimates production according to predefined recovery rates. These recovery rates are based on a survey of more than 80 US mines [14]. CoalVal was reviewed in 2005 [15]. The review, performed by a committee of invited reviewers from West Virginia University, Peabody Energy, Arch Coal, the U.S. Bureau of Land Management, Mine Safety and Health Review Commission and the Kentucky Geological Survey, recommended this approach for regional modeling with the caveat that the limitations of publicly available data be recognized. However, they also said that it is "doubtful that adequate site-specific washability analyses have been incorporated into the assessment," suggested that the financial life time for the cash flow analysis of 10 years was too short. The GIS approach is very labor-intensive, requiring a GIS analysis and then user selection of "logical mining units" (LMUs). These LMUs are then input to Coalval to determine the cost of extraction by user selected mining methods. This procedure was followed in an EIA study [16], which examined the cost of mining the remaining Pittsburgh coal seam by apportioning the resource into LMUs and estimating mining costs in Coalval. In the analysis, longwall mining methods were assigned to LMUs with coal thickness greater than 42" and more than 56 million short tons; room and pillar methods were applied to LMUs with height greater than 42" and more than 13.5 million short tons of coal, and surface mining methods were applied to LMUs with 12-36" coal thickness and a minimum of 1.2 million short tons of coal to be mined over the mine life of 10 years for underground mines and 5 years for a surface mine. Not all the coal was deemed mineable. Based on the analysis of 7,753 tons of mineable coal, and how LMUs were assigned, the analysis showed that LW costs ranged from $18 – 28/ton (5130 tons of the total), CM costs range from $19-34/ton (2170 tons), and SM costs range from $21-27/ton (452 tons).

This work differs from the CoalVal work because it is not dependent on user analysis of a resource in order to create a LMU. The user does not need to generate equipment lists or operating costs; all this is already in the model. The model in this chapter simulates generalized surface and underground mines, which are representative of "typical" mines – stochastic distributions of capital and operating costs are embedded in the model. The user inputs the geological characteristics of the resource. The model estimates recovery rate, production, and cost by simulating contemporary surface and underground mining practices for the input seam thickness and depth. It assumes that the resource area could be anywhere within 1 – 3,600 square miles.

3 Method to estimate production and cost ranges

The model is different than past mining models. It bridges the gap between site specific modeling and a general resource allocation evaluation. The data input into the model is collected from the literature, to best represent the average coal mine. The model's results are representative of the average mine performing under average conditions. As discussed further, all production and cost data are input as ranges in order to capture the full range of mine operations. The model's output is an estimated range that captures the uncertainty associated with mine production and costs. These ranges are representative of the variety of coal mining operations throughout the country.

Mining conditions vary nationwide, due to site specific geological conditions, and operational practices. Rather than assessing production and cost associated with a specific equipment configuration or practices adjusted for challenging conditions, the model predicts a range of estimates for a range of equipment configurations. The output accounts for the range of equipment, configurations, overburden composition, and seam thickness variation.

To create a model that represents the inherent uncertainty related to a wide array of mining practices, a model was built in Analytica – a stochastic modeling tool that allows the user to estimate a range of potential outcomes. The components of the model, such as the timing and capacity of machinery, capital costs, and tax rates, are input as ranges to reflect mine operation and data uncertainty. The input range bounds determine the output range bounds. The top end of the range represents the 95th percentile, or highest possible value. The bottom end of the range represents the 5th percentile, or lowest possible value. The model results are 5th – 95th percentile estimates range, which represents the widest range of possibilities. It shows the range in production and cost resulting from all possible equipment sizes, timing and configuration for a mine system.

3.1 U.S. coal characteristics

This model estimates production rates and costs for U.S. bituminous coal, which has accounted for over 50 percent of annual U.S. coal production since records have been kept in 1950 [17]. Coal density is 1705 – 1846 tons/acre-foot [18]. Overburden, the material overlying the target coal seam for mining, may contain some or a combination of sandstone, clay, gravel, shale, and various other materials. An overburden density range that accounts for all these possibilities is 1900 – 3190 tons/acre-ft with a swell factor, or ratio of expanded cut rock volume to its original volume, of 1.25 – 1.6 [18]. The volume of coal cut by each method is based on the coal type; the density can be changed in order to evaluate other types of coal. For example, the volume of coal extracted by a continuous miner cut is estimated by:

$$T_{CM} = CM_D \times Th \times CM_W \times \rho_B \qquad (1)$$

Where:
T_{CM} = tons of coal cut by the continuous miner
CM_D = continuous miner cutting depth
Th = seam thickness
CM_W = continuous miner cutting width
ρ_B = bituminous coal density

Other coal densities may be substituted may be substituted for the bituminous coal density in order to estimate the volume of coal cut.

3.2 Coal mining cost and production model

The model estimates the average levelized cost to mine coal in constant 2005$. It was developed specifically to evaluate U.S. mining operations. The model approximates the cost to mine coal, based on resource size. A schematic of the resource's simplified dimensions, as model input, is shown in Figure 2. Overburden depth, seam thickness, interburden depth, and resource width and length are inputs into the model. The model estimates production and costs in a single seam for underground mines, and up to ten seams for surface mines. Figure 2 is an example showing two seams. The overburden depth, seam thickness, interburden depth, and resource width and length are inputs into the model.

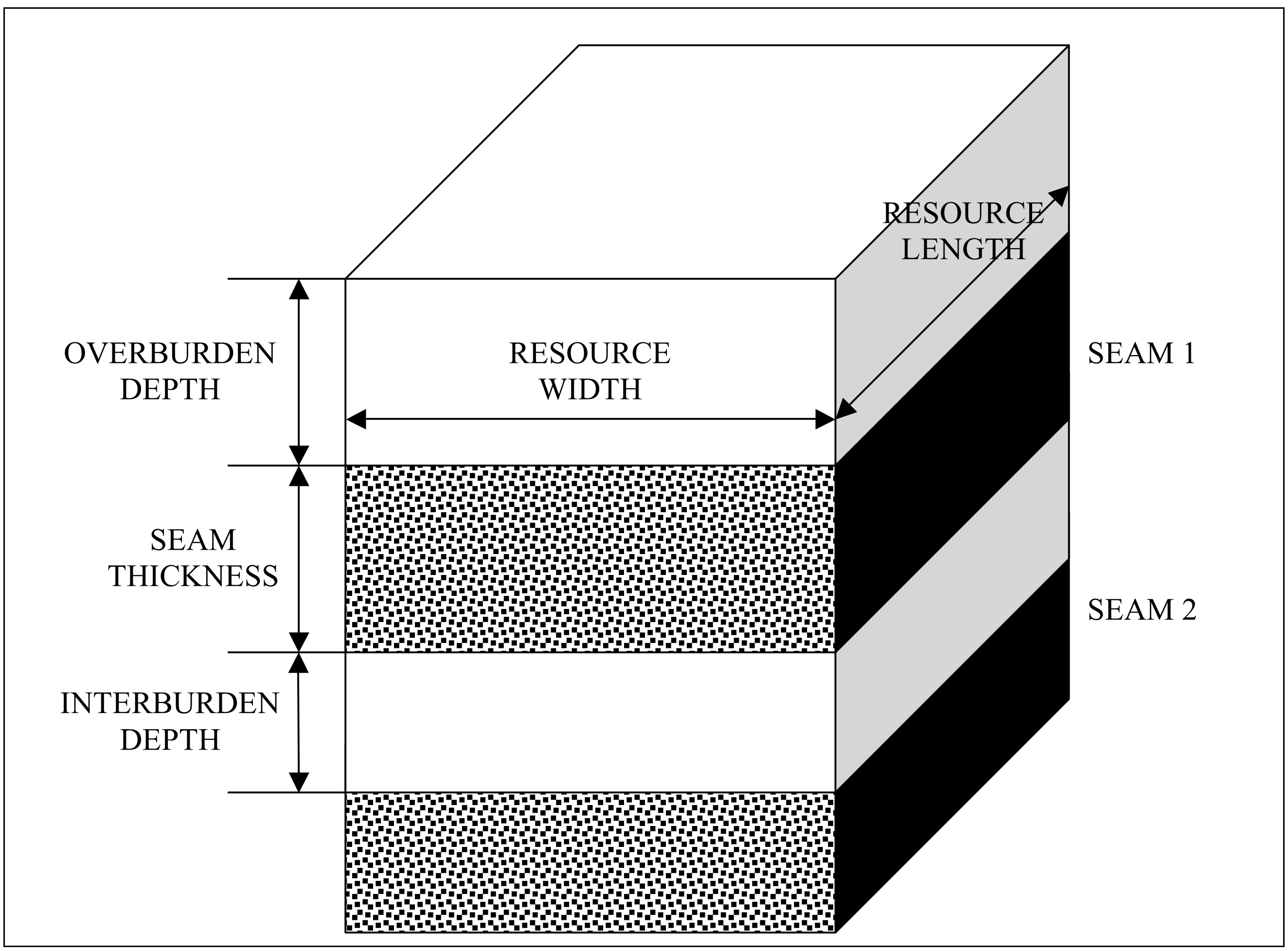

Figure 2. Simplified coal resource dimensions

The model is capable of modeling production and costs for a surface mine operating in up to ten seams. However, continuous and longwall mines are simulated in single seams only. These parameters are indicative of the total amount of mine area that may be covered by the simulated mines. Based on this geological data, the model defines the dimensions of longwall, continuous, and surface mines that could be constructed to extract the resource. Physical aspects of the modeled mines that are dependent on the depth, width and length of the resource are: continuous mine pillar width, longwall panel width and length, and surface mine pits and roads. The dimensions of the coal resource are used to estimate the size and number of the underground mine workings or surface mine pits. Unit operations can be scheduled appropriately, knowing the physical space of the mine. Sizes and unit operations for mines based on input geological parameters these mine workings are defined by the model, following predominant methods in mine design literature [3, 5, 6, 8].

The model schedules unit operations based on estimated sizes for surface mining pits, continuous mine rooms and pillars, and longwall panel and development sections. Equipment is sized according to the mine design literature [18-21]. Based on estimated production rates, it sizes a Level III or IV preparation plant according to run-of-mine production levels [22] simulated by the model. It calculates US federal taxes and regulatory fees; all equipment cost estimates are based on reported US mine cost data [18, 23]. Furthermore, the model uses US based equipment timing study data [18, 24-28] to configure unit operations and estimate production rate. The unit operations and preparation plant modeling are detailed in Appendix A.

Operations differ according to mine type. In a surface mine, overburden must be removed in order to access a coal seam. If multiple seams are surface mined, interburden between seams must be removed in order to access subsequent coal seams. All the material, overburden and coal, is loaded by hydraulic excavators and removed by large trucks. In an underground mine, entries must be developed and hoists inserted in order to access the coal. The model estimates the size of the required ventilation system, so that methane levels within the mine may be mitigated. The model also schedules coal face cutting, roof bolting, coal loading and tramming in continuous mines and longwall development sections. It schedules development sections and longwall panels in longwall mines; the shearer timing and cutting rate define the panel timing. Based on the scheduling of unit operations according to equipment capacity, cutting and travel rate, production rate and mine lifetime are estimated.

The average annual production rate and resulting average cost over the time needed to mine the coal are the primary model outputs. The range of these estimates captures the variation in production and cost. Production rate and operations vary from year to year, depending on mine type and practice. For example, longwall mine production will vary according to whether the longwall panel(s) have started. During the longwall development phase, coal is produced solely from the continuous miners in the development sections for the panel. When the retreating operation in a panel begins, the production rate increases because the yield of coal from the shearer is much greater than that of continuous miners. Additionally, if development for more panels is underway while the shearer is in operation, a maximum production rate for the longwall mine will be achieved. Cost varies per year as well. Several costs are dependent on production rate, such as income and production based taxes, royalties. In addition to the variation in costs due to variable production rate, capital costs to replace equipment, and straight-line depreciation results in equipment costs that differ on a yearly basis.

Costs corresponding to the process steps simulating in the model are estimated, as described in Appendix A. The four main process categories for these costs are premining, mine development, exploitation, and closure, as summarized in Table 1. Premining costs are comprised of permitting and land clearing costs. Land clearing costs are incurred to remove plant growth and prepare surface land for support buildings, shafts, entry points, and mine pits. Mine development includes the costs to access the coal seam, whether by breaking up the overburden by explosives and trucking it to storage or disposal, or sinking shafts and installing hoists. The overburden removal cost is the cost to move the overburden from a surface mining pit to a storage or disposal area. It does not include the cost of drilling and explosives; these costs are included in the ANFO explosives cost. Operating costs are labor payroll, fuel, electricity and lubricating oil, royalties, taxes and regulatory fees, equipment capital and the washing cost in a preparation plant. It is assumed that closure costs are covered by the reclamation bond premium, which may extend for 5 – 50 years after mine closure.

Table 1 Mining process and cost categories

Premining	Mine Development	Exploitation	Closure
Permitting Land clearing	Explosives Overburden removal Shaft capital cost Hoist capital cost	Payroll Fuel and lubricating oil (all equipment, including shaft and hoist) Utilities (all equipment, including shaft and hoist) Royalties Taxes (state, real property, tangible property, SMCRA, income, excise) Haulage (underground or in pit and surface transport to on site washing plant) Equipment capital costs, includes prep plant Washing cost	Reclamation bond premium

3.3 Coal mining model parameters

The model simulates a range of equipment configuration, capacities, timing, and costs, all described in Appendix A. For each mine type simulated, the model bases its production and cost estimate on the equipment sizes, costs and timing reported in the literature. Data collected includes, but is not limited to:

1. Time worked; hours per shift, shifts per day, days per year,
2. Number of employees,
3. Number of mining units (continuous miners, shovels, augers, longwall shearers),
4. Traveling time per mining unit
5. Cutting rate and yield per cut for each mining unit
6. Delays resulting from building water, electricity, and ventilation supports for mining operations
7. Operations and maintenance cost per unit operation

Most of these data are input into the model as ranges. For example, the model assumes one to seven surface mining teams comprised of one to two excavating shovels or bulldozers, two to five trucks varying from 125 – 240 tons, a grader and a drill. In addition to these machines, the mine has surface support buildings, water and wastewater treatment facilities and access roads. The costs for the equipment, and more detail about their operation, may be seen in Appendix A. Furthermore, information about how costs are estimated by the model, including assumptions about commodity prices and coal sales price, are summarized as well.

4 Validation

The model was validated by simulating real U.S. coal mines, for which seam thickness and depth data was available. The simulation results were compared to the mines' coal prices and production rates. Seventeen longwall mines, ten surface mines, and fourteen continuous mines were simulated. The seam characteristics were input into the model in order to simulate mining under those conditions. The mine's coal reserve was unknown; the model assumed that the reserve can be anywhere from 1 – 2 million acres worth of coal. The model's estimated 5^{th} – 95^{th} percentile ranges of production rate and cost were compared to the mine's historical production and price data. It was assumed that the coal market is close to equilibrium, so that coal price can be compared to projected mining costs.

4.1 Mine sample description and data sources

A comprehensive production and geological dataset for all U.S. coal mines is not available. The dataset described here is the most complete compilation of operating conditions and production rates from public data. The mine and coal seam data used in validation are compiled from the Energy Information Administration (EIA) Annual Coal Report, Illinois Department of Mines and Minerals annual statistical report, *Coal Age* magazine, and the Society of Mining Engineers Mining Engineering Handbook. The most complete reports are the Illinois Department of Mines and Minerals annual statistical reports and the *Coal Age* longwall census. The first is specific to Illinois, but provides detailed configuration and production information about all Illinois mines; the second provides complete description of all U.S. longwall mines' configurations but no production data. The Illinois Department of Mines and Minerals annual statistical reports summarize Illinois coal mines' production rate, seam characteristics, and number of continuous mining units. The mines described in these reports are the lowest producers in the dataset. Coal resource and production data for mines outside Illinois were combined from several sources. Production data for the fifty top producing US mines is available from the EIA Annual Coal Report; geological data for longwall mines and some of the surface mines on the list were available from the *Coal Age* longwall census and Society of Mining Engineers' 2nd edition Mining Engineering Handbook, respectively. The *Coal Age* longwall census also describes seam depth and thickness, as well as the number of panels and their dimensions. The uncertainty inherent in values reported varies by source. The Illinois Department of Mines and Minerals and EIA report discrete values, whereas the longwall census and SME report discrete values and ranges. The reporting style likely reflects the amount of information available from the operator.

Surface, continuous and longwall mines are all simulated according to the geological data collected. The seam depth and thickness data are input into the model in order to simulate the sample mines. The model is run for a range of coal resource areas between 494 – 2,300 acres. Some of the mine seam thicknesses, overburden and interburden depths are reported in the literature as ranges, and input into the model as a uniform distribution of minimum to maximum value. The geological data for the sample mines are summarized in Table 2 - Table 4, while the ownership information and production data are presented in Table 5 - Table 7 for the surface, continuous and longwall mines, respectively.

The sample represents a breadth of production ranges and operations in varying geological conditions. Because more data was available throughout the U.S. for surface and longwall mines, these sample mines operated in the widest range of conditions. Continuous mines operated in the narrowest range of conditions because all sample data is from a few seams in Illinois. Surface mine seam thickness ranged from 0 – 55 ft, with up to ten seams extracted by a single operation. Interburden and overburden depths for the seam mined by the sample mines ranged from 10 – 200. Longwall mines included in the sample operated in seams almost as thick, 5 – 23 ft, and at much deeper depths, 300 – 9300 ft. Some longwall mines had more than one longwall panel. It is assumed that both panels are operating under the same conditions. In the case that seam thickness and overburden depth were reported for each panel, the widest value range for seam thickness and overburden depth was used. Continuous mines operated in small seams, with thickness ranging from 5 – 8 ft and seam depths of 110 – 900 ft.

Table 2. Geologic characteristics for selected U.S. surface mines[a]

State	Mine Name	Seam Name(s)	Seam Minimum Thickness, ft	Seam Maximum Thickness, ft	Minimum Seam Depth, ft	Maximum Seam Depth, ft
IL	Wildcat Hills	No. 6	4.5	NA	50	NA
		No. 7	2	NA	100	NA
IL	Eagle Valley	No. 6	4	NA	65	NA
IL	Creek Paum	M-Boro	4	NA	70	NA
		No. 5	4	NA	100	NA
		No. 6	6	NA	100	NA
IL	Elkville	No. 6	6	NA	100	NA
		No. 7	8	NA	90	NA
IL	Prairie Eagle	No. 7	2	NA	28	NA
IL	Red Hawk	No. 5	2	NA	110	NA
		No. 6	6	NA	80	NA
IL	Friendsville	Friendsville	5	NA	60	NA
CO	Colowyo Mine	Y3	5	NA	33	NA
		Y2	3	NA	36	NA
		X	13	NA	82	NA
		A2	4	NA	41	NA
		A3	2	NA	10	NA
		B	6	NA	54	NA
		C	6	NA	35	NA
		D	10	NA	29	NA
		E	7	NA	29	NA
		F	5	NA	21	NA
WY	Jacobs Ranch Mine	Upper Wyodak	0	8	150	200
		Middle Wyodak	40	55	0	38
		Lower Wyodak	0	9	0	73
TX	Big Brown Strip	NA	5	8	40	155
		NA	6	10	28	45

[a]Sources: [18, 52].
NA = Not available

Table 3. Geologic characteristics for selected U.S. continuous mines[a]

State	Mine Name	Mine Name	Seam	Seam Thickness ft	Seam Depth ft
IL	ICG Illinois	Viper	IL #5	6	280
IL	Freeman United Coal Mining.	Crown 2	IL #6	8	320
IL	Freeman United Coal Mining.	Crown 3	IL #6	8	365
IL	Knight Hawk Coal, LLC	Prairie Eagle U/G	IL #6	6	120
IL	Coulterville Coal Co	Gateway	IL #6	5	200
IL	Arclar Company	Willow Lake	IL #5	5	270
IL	Black Beauty Coal Co.	Wildcat Hills	IL #6	5	390
IL	Nubay Mining	Liberty Mine	IL #5	6	257
IL	Black Beauty Coal Co.	Riola	IL #6	6	250
IL	Black Beauty Coal Co.	Vermillion Grove	IL #6	6	250
IL	Wabash Mine Holding Co.	Wabash	IL #5	7	850
IL	White County Coal Corp.	Pattiki	IL #6	8	900
IL	Mach Mining LLC	Pond Creek	IL #6	7	460

[a]Sources: [52].

Table 4. Geologic characteristics for selected U.S. longwall mines[a]

State	Mine Name	Seam Name	Seam Min Thickness, ft	Seam Max Thickness, ft	Min Seam Depth, ft	Max Seam Depth, ft
CO	Elk Creek	D	9	15	300	1600
CO	West Elk	B	23	NA	600	1400
CO	Foidel Creek Mine	Wadge	8	10	600	1400
IL	Galatia	Harrisburg (No. 5)	5	5	500	800
IL	Galatia	Harrisburg (No. 5)	5	5	450	550
NM	San Juan	Fruitland No. 8	10	15	450	1200
OH	Century Mine	Pittsburgh (No. 8)	5	NA	400	600
OH	Powhatan No. 6	Pittsburgh (No. 8)	5	NA	400	600
PA	Bailey	Pittsburgh	5	6	600	1000
PA	Enlow Fork	Pittsburgh (No. 8)	5	6	600	1000
PA	Enlow Fork	Pittsburgh	5	6	600	1000
PA	Cumberland	Pittsburgh (No. 8)	7	8	750	1050
PA	Emerald	Pittsburgh (No. 8)	6	7	380	950
UT	Sufco	Upper Hiawatha	7	17	800	1100
UT	Dugout Canyon	Rock Canyon	6	8	1000	1600
VA	Buchanan	Pocohontas No. 3	5	6	1400	2000
WV	McElroy	Pittsburgh	5	5	500	1000
WV	Loveridge	Pittsburgh	8	NA	1000	9300
WV	Robinson Run	Pittsburgh	8	NA	500	900
WV	Federal No. 2	Pittsburgh	8	NA	750	1400

[a]Source: [37, 53].

4.1.1 Simulation comparison data

Sample mine production, and state and national coal prices were used to evaluate the model's simulation output. These data for the three mine types, along with location and owner, are shown in Table 5 - Table 7. Average 2006 surface mine production is 5.0 million tons/year (Table 5), average continuous mine production is 1.2 million tons/year (Table 6), and average longwall mine production was 5.6 million tons/year (Table 7). The 2006 average national prices of surface and underground mined coal were $22/ton and $48/ton [53], respectively.

The surface mine data set includes small mines in Illinois and larger mines in Colorado and the Powder River Basin. The average production rate among large surface mines is 18 million tons per year [54]. At 40 million tons per year output, Jacobs Ranch mine produced more than twice the average top producing mine. Colowyo and Big Brown Strip are also among the top producing U.S. surface mines; they produced 6.2 million and 4.5 million tons in 2006, respectively.

Table 5. Production and owner information per surface mine used in validation[a]

State	Company Name	2006 Production, Million Tons	Owner	State Coal Price, $/Ton
IL	Wildcat Hills	2.6	Black Beauty Coal Co	31.17
IL	Eagle Valley	0.2	Black Beauty Coal Co	31.17
IL	Creek Paum	1.4	Knight Hawk Coal, LLC	31.17
IL	Elkville	0.4	S Coal Co	31.17
IL	Prairie Eagle	0.8	Knight Hawk Coal, LLC	31.17
IL	Red Hawk	0.7	Knight Hawk Coal, LLC	31.17
IL	Friendsville	0.3	Vigo Coal Co	31.17
CO	Colowyo Mine	6.2	Colowyo Coal Company LP	24.27
WY	Jacobs Ranch Mine	40.0	Jacobs Ranch Coal Company	9.03
TX	Big Brown Strip	4.5	TXU Mining Company LP	18.61

[a]Sources: [52, 53].

Continuous mine production data used in this validation were reported in the Illinois Department of Mines and Minerals annual statistical reports [52]. Coal price data per state and the national average is also available [53]. None of the continuous mine owners are publicly traded companies. The owner per each mine, their 2006 production rate, and number of continuous mining machines are shown in Table 6. The least producing continuous mine is the Prairie Eagle mine. It produces an order of magnitude less than the next lowest producing mine. At Prairie Eagle, continuous mine production is not the primary focus of the mine, instead it provides some additional production to supplement the surface mine.

Table 6. Production and owner information per continuous mine used in validation[a]

Owner	Mine Name	Number of Continuous mining Units	2006 Production, Million Tons	State Coal Price, $/Ton
ICG Illinois	Viper	6	3.9	31.17
Freeman United Coal Mining	Crown 2	4	1.3	31.17
Freeman United Coal Mining	Crown 3	5	1.6	31.17
Knight Hawk Coal, LLC	Prairie Eagle U/G	1	0.1	31.17
Coulterville Coal Co	Gateway	4	2.4	31.17
Arclar Company	Willow Lake	10	3.6	31.17
Black Beauty Coal Co.	Wildcat Hills	2	0.5	31.17
Nubay Mining	Liberty Mine	NA	0.3	31.17
Black Beauty Coal Co.	Riola	2	0.3	31.17
Black Beauty Coal Co.	Vermillion Grove	4	1.4	31.17
Wabash Mine Holding Co.	Wabash	6	1.2	31.17
White County Coal Corp.	Pattiki	8	2.5	31.17
Mach Mining LLC	Pond Creek	2	0.1	31.17

[a]Source: [52, 53].

Longwall description and ownership are summarized in Table 7. The range of production among the sample mines is 4.4 – 9.6 million tons. The average production rate of large longwall mines is 6.5 million tons [53]; 8 of the sample mines exceed this production level and 14 are below it. All have one operating longwall except Galatia, Bailey, Enlow Fork, and McElroy. These two panel mines are located in 5 feet thick seams, but owe their high output to having more than one panel.

Table 7. Production and owner information per longwall mine used in validation

State	Mine Name	2006 Production, Million Tons	Owner	State Coal Price, $/Ton
CO	Elk Creek	5.1	Oxbow Mining	24.10
CO	West Elk	6.0	Arch Coal Incorporated	24.10
CO	Foidel Creek Mine	8.6	Peabody	24.10
IL	Galatia	7.2	Foundation	31.17
NM	San Juan	7.0	BHP Billiton	29.15
OH	Century Mine	6.5	American Energy Corporation	27.40
OH	Powhatan No. 6	4.4	Ohio Valley Coal	27.40
PA	Bailey	10.1	Consol Energy	37.40
PA	Enlow Fork	10.7	Consol Energy	37.40
PA	Cumberland	7.5	Foundation Coal	37.40
PA	Emerald	5.9	Foundation Coal	37.40
UT	Sufco	7.9	Arch Coal Incorporated	24.98
UT	Dugout Canyon	4.4	Arch Coal Incorporated	24.98
VA	Buchanan	5.0	Consol Energy	52.99
WV	McElroy	10.5	Consol Energy	45.94
WV	Loveridge	6.4	Consol Energy	45.94
WV	Robinson Run	5.7	Consol Energy	45.94
WV	Federal No. 2	4.6	Peabody	45.94

[a]Source: [53].

4.2 Production and Price Data Are Complicated

No singular geographical, geological, or operational factor can predict the production rate of any of the sample mines. Site specific operating conditions that the model can not account for includes innovative technology, equipment configuration or quantity, more efficient management, miner training and skills, which lend themselves to a high production rate. The number and type of equipment is likely the greatest factor in determining production rate differences among mines located in similar geological conditions.

It is not possible to truly correlate productivity according to geography, seam thickness, seam, or company:

1. Production may vary within a state. For example, Illinois surface mine production rates range from 0.1 – 2.6 million tons per year. Illinois continuous mine production rates vary between 0.1 – 3.9 million tons per year. The longwall mines, Century and Powhatan, are in the same seam in Ohio; however their production rates are 6.5 million tons and 4.4 million tons per year.

2. Production may vary within a seam. It is dependent on the available resource, and the number of extractive unit operations used to mine it. There are several examples that can be drawn from the sample mine data set. The sample set includes two surface mines that are both mining in Illinois No. 6 and No.7; these mines, Wildcat Hills and Elkville, produce 2.6 million tons and 0.4 million tons, respectively. Wildcat Hills is the larger producer, presumably, because the seam sections mined by Elkville have greater overburden than those mined by Wildcat Hills. The continuous mines, Willow Lake and Liberty, are both located in the No. 5 seam, at the same reported thickness. However, Liberty produces less coal than Willow Lake because it is in a deeper section of the seam. Two longwall mines in the Pittsburgh seam produce more than their neighbors because they have two panels. The Century, Powhatan No. 6, Bailey and Enlow Fork mines are all located in the Pittsburgh seam, at the same reported thickness. The Bailey and Enlow Fork mines are located in deeper seam sections than the Century and Powhatan mines, but they are more productive because they have two longwall panels. Because they have two panels, they are more productive than the Cumberland and Emerald mines, which are also in the Pittsburgh seam, even though the latter mines are in a thicker portion of the seam.

3. Production may vary within a company because management and equipment configuration can vary among mines. The Black Beauty Coal company owns two surface mines in Illinois that produce 0.17 million tons and 2.6 million tons; Knight Hawk coal owns three surface mines whose production range from 0.7 – 1.4 million tons per year. Nothing is known about the mine's equipment configuration, and reasons for the production difference. Black Beauty Coal owns two continuous mining operations in Illinois that are included in this sample, Riola and Vermillion Grove, which are located in the No. 6 seam at the same seam thickness and overburden depth. However, the Vermillion Grove mine produces about four times the amount that Riola does. It has four continuous miner units, while Riola has two. In addition to being less equipped than Vermillion Grove, Riola has roof control problems [55]. Consol Energy owns six of the seventeen longwall mines examined for the data sample. However, the production rates for these mines vary from 5.7 million tons of coal per year for the Robinson Run mine in West Virginia to 10.7 million tons of coal per year for the Enlow Fork mine in Pennsylvania. The Robinson Run mine is located under shallower overburden than the Enlow Fork mine, and is located in a thicker portion of the Pittsburgh seam. The reason for this discrepancy is that there are two longwall panels operating at the Enlow Fork mine. There are also two panels operating at the Bailey and McElroy mines.

4.2.1 Factors Affecting Mining Costs That Can't Be Modeled

Although price is not the same as cost, it is the only publicly coal valuation data available. The cost calculated by the model is not fully representative of the price charged by a company. Energy and sulfur content dictate the coal's quality and demand for it. Furthermore, there are operating costs beyond the minesite that are included in the price of coal, and sometimes transportation costs are added; these additional costs account for part of the difference between cost and price. In order to best estimate the difference between cost and price, the owner's annual revenue and profit were examined. Publicly held companies report their revenue and profit to the Securities Exchange Commission. Several of the mines are owned by large publicly held companies, and their overall revenue and profit are published in their annual 10-K report. The owner of each mine, their 2006 production rate, the 2006 price of coal in that state, and availability of publicly reported revenue and profit are shown in Table 4-6. None of the continuous and surface mine owners are publicly traded. Some mining companies in the sample are small, local companies that are not subsidiaries of a larger company; no 10-K report could be found. The rest of this discussion focuses on longwall mining, which can provide an example of factors affecting cost. The 2006 national price of coal, which is also used in order to validate the model's output, was $38 per ton. The national price is used because the coal price varies per region based on a variety of coal quality and extraction factors previously discussed, and can provide insight into how the model's cost estimates at a nationwide level.

Table 8 summarizes annual revenue and net income reported by publicly held companies that own mines included in the data sample. All of these companies, except for BHP Billiton, specialize in coal mining. The larger revenues and net incomes reported by BHP Billiton in their 2007 annual report are likely due to their sales in other minerals. These data are used to estimate the price of coal to be charged, based on the estimated mining costs output by the model.

Table 8. Revenue and Net Income Reported by Public Companies (Billion$)

	Consol Energy[1]		Arch Coal Incorporated[2]		Peabody[3]		Foundation Coal[4]		BHP Billiton[5]	
	Revenue	Net Income	Revenue	Net Income	Revenue	Net Income	Revenue	Net Income	Revenue	Net Income
2007	3.72	0.27	2.41	0.17	4.57	0.26	1.49	0.03	41.27	13.50
2006	3.72	0.41	2.50	0.26	5.14	0.60	1.47	0.03	34.14	10.53
2005	3.81	0.58	2.51	0.04	4.55	0.42	1.32	0.09	24.76	6.63
2004	2.78	0.20	1.91	0.11	3.55	0.18	0.10	-0.05	NA	NA
2003	2.22	-0.01	NA	NA	2.73	0.03	0.10	0.03	NA	NA
2002	2.18	0.01	NA	NA	2.72	0.11	0.90	0.03	NA	NA

1 [56]
2 [57]
3 [58]
4 [59]
5 [60]

The ratio between revenue and net income illustrates the percentage of revenue that may be attributed to profit or cost. The revenue and income for each company is shown in Table 3. From this, the percent of revenue that is cost is determined as:

$$c_i = \frac{(R_i - I_i)}{R_i} \times 100 \qquad (2)$$

where: c_i = ratio of cost to revenue for company i
Ri = revenue for company i

The model's cost ratio compared to historic price is determined as:

$$r_{i,M} = \frac{C_{i,M}}{P_{i,M}} \times 100 \qquad (3)$$

where: $c_{i,M}$ = ratio of cost to price for company i, mine M
$P_{i,M}$ = price for company i, mine M

Equation 3 is computed using state and national price for coal.

The results of equations 2 and 3 per each mine is shown in Table 9.

Table 9. Percentage of Revenue Attributed to Cost, based on Company 10-K reports and Model Estimates

Mine Name	Ratio of Cost to Revenue	Owner
Elk Creek	NA	Oxbow Mining
West Elk	94	Arch Coal Incorporated
Foidel Creek	93	Peabody
Galatia	98	Foundation
San Juan	70	BHP Billiton
Century and Powhatan	NA	American Energy Corporation
Bailey and Enlow Fork	93	Ohio Valley Coal
Cumberland	98	Consol Energy
Emerald	98	Consol Energy
Sufco	94	Foundation Coal
Dugout Canyon	94	Foundation Coal
Buchanan	93	Arch Coal Incorporated
McElroy	93	Arch Coal Incorporated
Loveridge	93	Consol Energy
Robinson Run	93	Consol Energy
Federal No. 2	94	Consol Energy

The Bailey and Enlow Fork mines are paired in Table 8 because they operate under the same geologic conditions; the same is true for the Century and Powhatan mines. The Century and Powhatan mines are each owned by non-publicly traded companies, so that revenue and income data for those companies is not available. In general, companies operated on a slim profit margin. On average, 3 – 7% of their income was pure profit. The exception is the San Juan mine, owned by the large international company, BHP Billiton. The additional charges can include transportation, or items tabulated in the company's annual report.

Looking at company 10-K reports, additional costs related to mining as reported by companies owning the sample mines are summarized in Table 10. These items are described as affecting the reported cost and revenue reported in their 10-K reports. Not all companies provided this information. The costs in Table 10, are the additional costs that comprise price, which cover fire costs, accidents, property acquisitions and sales, are costs that reflect operation of a company beyond a single mine operation. The model does not reflect these costs, only the costs of a greenfield mine to extract coal under set geological conditions.

Table 10. Items that Affect Reported Costs and Profit

		Cost (-) or Profit (+), million $		
Company	Item	2006	2005	2004
Consol Energy	Buchanan Mine Fire	0	-34	NA
Consol Energy	Buchanan Mine skip hoist accident	0	-3	NA
Consol Energy	Sales contract buy outs	0	-13	NA
Consol Energy	Litigation settlements and contingencies	-1	-10	NA
Consol Energy	Incentive compensation	-24	-35	NA
Consol Energy	Bank fees	-9	-12	NA
Consol Energy	Accounts receivable securitization fees	0	-2	NA
Consol Energy	Terminal/River operations	-51	-24	NA
Consol Energy	Stock-based compensation expense	-23	-4	NA
Consol Energy	Miscellaneous transactions	-12	-19	NA
Arch Coal	Sale of select Central Appalachia operations	NA	75	0
Arch Coal	Peabody reserve swap and asset sale	NA	46.5	0
Arch Coal	West Elk combustion event			0
	Idling	-30		
	Insurance recovery	42	33	
Arch Coal	Accounting for pit inventory	-41	0	0
Arch Coal	Sales of interest in Natural Resource Partners LP	0	0	91
Arch Coal	Acquisition of Triton Coal Company, LLC	0	0	-382
Arch Coal	Acquisition of remaining interests of Canyon Fuel	0	0	NA

4.3 Results

Although mine performance varies throughout the country, the model is blind to geographic location. Results are presented and discussed by mine type, and are explained according to geological conditions, and known equipment configuration input into the model.

The model's simulated production rate, and costs capture most of the actual output and price. Model results are dependent on data uncertainty. The size of range reflects the availability of data, and whether the data were input to the model as discrete values or ranges. Production rate is directly related to seam thickness in the model. Thicker seams have higher production rates than thinner ones. As expected, when more mining equipment units are included in the mine simulation, the estimated production rate increased. The model estimated the tightest range of production rates for mine types that had discretely reported geological characteristics. Therefore, it estimated the tightest ranges for continuous mining, followed by surface mining. The ranges of longwall estimated production rates and costs are greatest because longwall geological data was typically reported as data ranges. The continuous mine geological data was reported as discrete data points.

The 50th percentile estimate is mentioned here as a means to compare the output of simulating all three mine types, although the complete range of estimates should be considered when evaluating the model output. Considering the 50th percentile estimate, the model estimated the highest production rates for surface mines and longwall mines. The 50th percentile production rates for surface mines, longwall, and continuous mines were 1.5 – 8.2 million tons, 3.6 – 16.1 million tons, and 1.2 – 1.9 million tons, respectively. The model estimated highest 50th percentile mining costs for continuous mining, $33 – 46/ton. Longwall and surface mines simulated 50th percentile cost estimates range from $13 – 41/ton and $19 – 40/ton, respectively.

4.3.1 Comparison of surface mine simulation results to real mine data

The estimated ranges of production costs and rates are compared to actual price and production. To simulate the sample surface mines, the model was run with its baseline assumptions as described in Appendix A. A sensitivity scenario, assuming one truck and shovel team rather than 1 – 7 surface mining teams, examines the model's ability to simulate small mines, such as the Illinois mines in the sample. Table 11 shows the 5th to 95th percentile range of surface mining cost estimates, based on the model's baseline of 1 – 7 surface mining teams. with the 50th percentile estimates delineated within the range. The 2006 state coal price (Table 5) is compared to the model's estimated production cost range in Table 12; it can be seen that the historical price data fall within the cost estimate range.

As shown in Table 11 (same data in Figure 3), the model overestimates production rate for the small mines, defined as those that produced less than 3 million tons of coal per year. These mine fewer and thinner seams than the larger mines. For the larger mines, the model predicted a suitable production range, such that the actual production rate was within 25 percent of the range if not falling within it.

Table 11. Relationship between actual surface mine production rates and predicted production rates for baseline model assumption of 1 – 7 truck and shovel teams. X indicates where actual production falls within range.

Mine	Predicted Production, million short tons						Actual Production
		5^{th}		50^{th}		95^{th}	
Wildcat Hills		2	x	17		51	3
Eagle Valley	x	2		12		31	0.2
Creek Paum	x	5		28		82	1
Elkville	x	2		12		31	0.4
Prairie Eagle	x	3		21		69	0.8
Red Hawk	x	1.2		6		16	0.7
Friendsville	x	3		16		45	0.3
Colowyo Mine	x	8		71		205	6
Jacobs Ranch Mine		6		39	x	134	40
Big Brown Strip		3	x	21		76	5

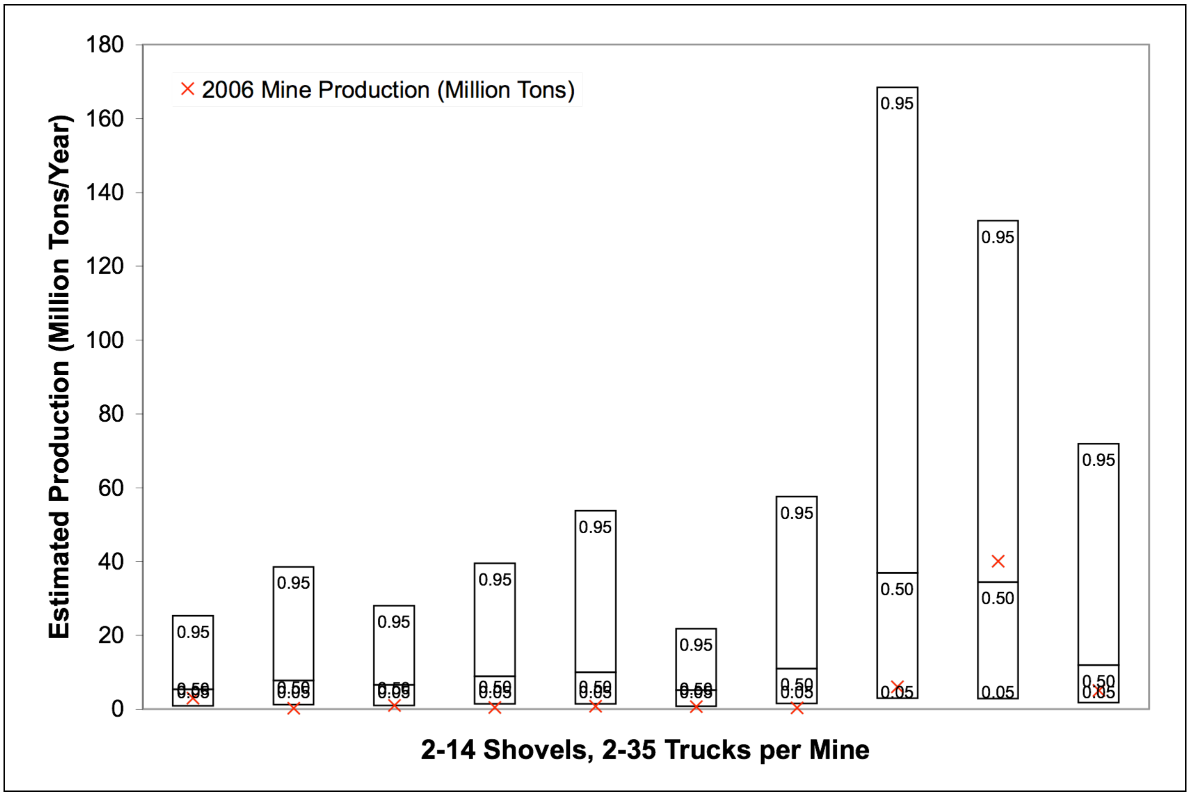

Figure 3. Actual surface mine production and predicted production rates for all mines.

Table 12 (same data are shown in Figure 4) shows that except for the Colowyo mine, the average state price fell within the predicted range. The model overestimated Colowyo production, resulting in cost underestimation. The cost to price ratio for all mines is low. The model simulated cost equal to or less than 60 percent of the historic price. The national coal price, $38/ton falls within the estimated ranges for all mines that produced 3 million tons or less.

Table 12. Actual surface mined coal price and predicted mining cost for baseline model assumption of 1 – 7 truck and shovel teams. X indicates where actual price falls within predicted range.

Mine	Predicted Cost ($/Ton)						Actual State Price ($/Ton)	Cost-Price Ratio
	5th		50th		95th			
Wildcat Hills	8		16	x	72		31	53
Eagle Valley	10		20	x	112		31	65
Creek Paum	6		12	x	38		31	40
Elkville	7		15	x	40		31	47
Prairie Eagle	9		29	x	209		31	92
Red Hawk	10		21	x	65		31	68
Friendsville	9		17	x	90		31	56
Colowyo Mine	5		9		15	x	24	39
Jacobs Ranch Mine	6	x	10		18		9	107
Big Brown Strip	7		13	x	36		19	70

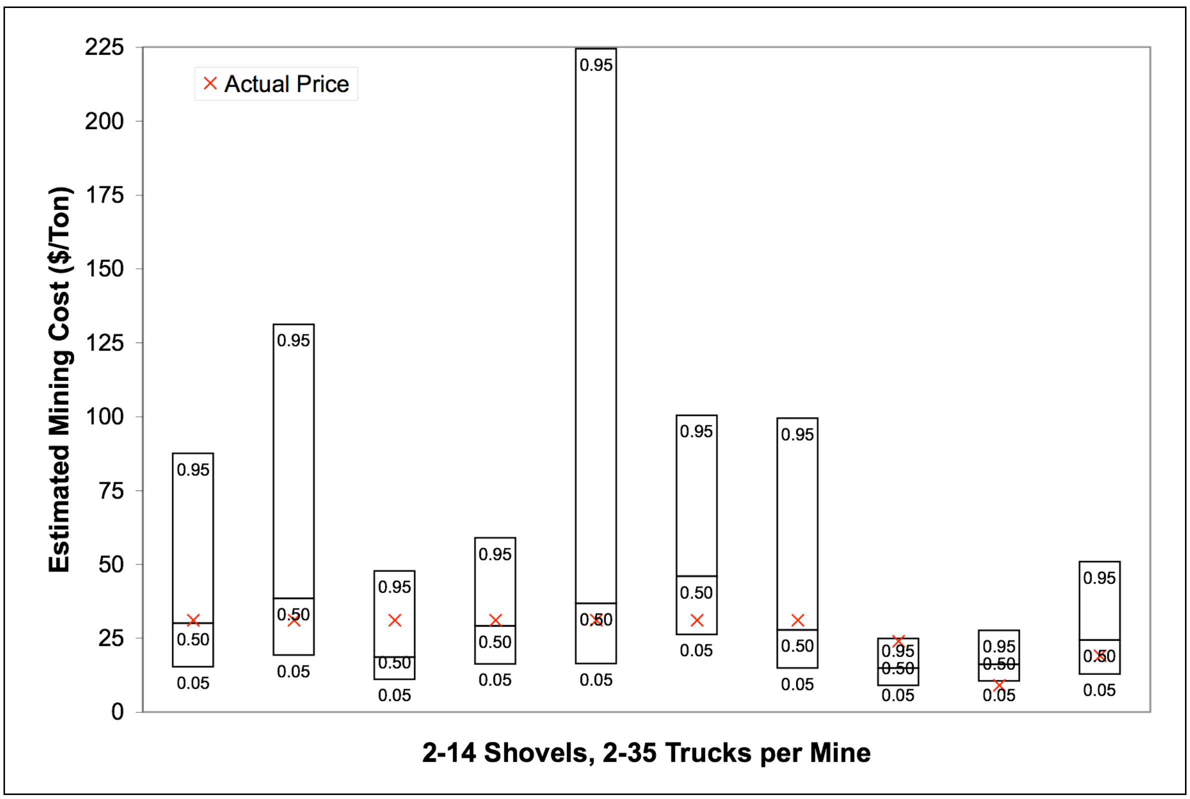

Figure 4 Comparison of actual surface mine coal price and predicted mining cost for all mines.

The sensitivity analysis shows that small mine production is still overestimated (Table 13), but less so than in the baseline scenario. Assuming one mining team decreased the breadth of the estimated production range. As shown in Table 14, the historic price falls within the predicted cost range. The simulated cost to price ratio for these small mines has increased, so that average 50th percentile cost is 105 percent of the state price. Based on these results, it appears that by adjusting the model to simulate fewer unit operations for a small surface mine, the model was able to estimate suitable cost and production ranges.

Table 13. Relationship between actual surface mine production rates and predicted production rates for small mine sensitivity analysis. Only mines producing 3 million tons or less are shown. X indicates where actual production falls within range.

Mine	Predicted Production, million short tons						Actual Production
		5th		50th		95th	
Wildcat Hills		0.9		3	x	6	3
Eagle Valley	x	0.7		2		5	0.2
Creek Paum	x	2		5		10	1
Elkville	x	0.8		2		5	0.4
Prairie Eagle	x	0.9		3		6	0.8
Red Hawk		0.4	x	1		2	0.7
Friendsville	x	0.9		3		6	0.3

Table 14. Actual surface mined coal price and predicted mining cost for small mine sensitivity analysis. Only mines producing 3 million tons or less are shown. X indicates where actual price falls within predicted range.

Mine	Predicted Cost ($/Ton)					Actual State Price ($/Ton)	Cost-Price Ratio
	5th		50th		95th		
Wildcat Hills	15		30	x	88	31	97
Eagle Valley	19	x	38		131	31	124
Creek Paum	11		19	x	48	31	60
Elkville	16		29	x	59	31	94
Prairie Eagle	16	x	37		225	31	119
Red Hawk	26	x	46		100	31	148
Friendsville	15		28	x	99	31	90

4.3.2 Comparison of continuous mine simulation results to real mine data

The exact number of continuous mining units for all the sample continuous mines is known. The actual price fell within the model's estimated cost ranges for three of the simulated mines, but the 50th percentile cost overestimated price by 24 – 100 percent. The 5th percentile cost overestimated price by 1 – 50 percent. Except in the cases of three very small producers (less than or equal to 0.3 million tons per year) the mine's actual production fell within the model's predicted range or, on average, the range endpoint was within 22 percent of the actual production (Table 15, the same data are shown in Figure 5). The actual state price was overestimated for nine of the simulated mines, meaning that it was less than the 5th percentile estimate. The national coal price, $38/ton, fell within the predicted range for all but three of the simulated mines (Table 16, same data shown in Figure 6).

Table 15. Relationship of actual continuous mine production rates predicted rates for known number of operating continuous miner units. X indicates actual production rate within range.

Mine		Predicted Production, million short tons 5th		50th		95th		Continuous Miner Units	Actual Production
Viper		2		2		3	x	6	4
Crown 2	x	1		2		3		4	1
Crown 3	x	2		3		4		5	2
Prairie Eagle	x	0.3		0.4		0.6		1	0.1
Gateway		0.9		1		2	x	4	3
Willow Lake		2		3	x	5		10	4
Wildcat Hills		0.2		0.3		0.5	x	1	1
Liberty Mine[a]	x	0.90		1		2		NA	0.3
Riola	x	0.5		0.8		1		2	0.3
Vermillion Grove		1	x	2		2		4	1
Wabash	x	2		3		4		6	1
Pattiki	x	3		4		6		8	3
Pond Creek	x	0.6		1		1		2	0.1

NA = Not available

[a]The number of continuous mining units for the Liberty Mine are unknown. The baseline output based on the assumptions explained in Appendix A, are provided.

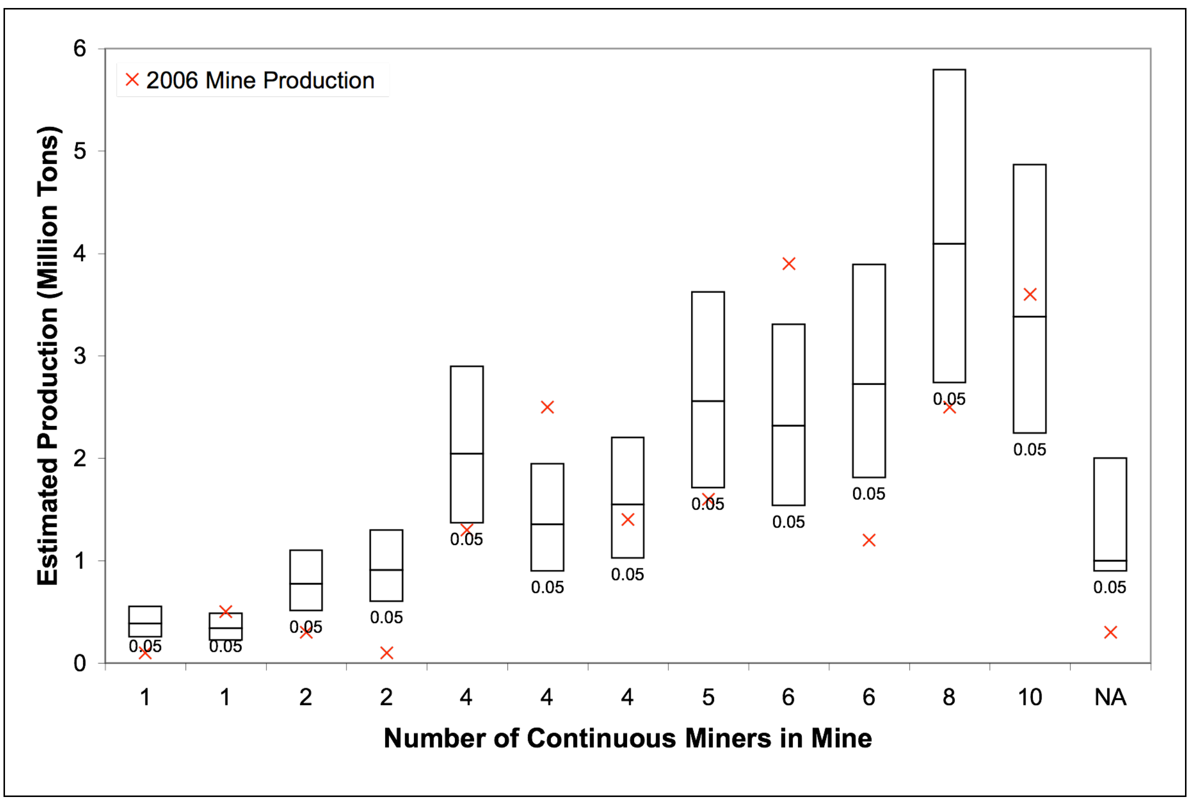

Figure 5 Comparison of actual continuous mine production rates and predicted rates for known number of operating continuous miner units.

Table 16. Relationship between actual and predicted continuous mining cost for known number of continuous miner units. X indicates actual cost within range.

Mine	Actual Cost ($/Ton)		Predicted Cost ($/Ton)				Cost-Price Ratio
			5[th]		50[th]	95[th]	
Viper	31	X	37		50	78	162
Crown 2	31		28	X	38	58	122
Crown 3	31		29	X	39	59	124
Prairie Eagle	31	X	41		57	85	183
Gateway	31	X	38		54	83	173
Willow Lake	31	X	46		63	101	202
Wildcat Hills	31	X	47		65	99	209
Liberty Mine[a]	31	X	36		48	69	155
Riola	31	X	35		49	75	159
Vermillion Grove	31	X	35		48	74	155
Wabash	31	X	32		43	69	140
Pattiki	31	X	31		42	66	135
Pond Creek	31		31	X	43	65	139

[a]The number of continuous mining units for the Liberty Mine are unknown. The baseline output based on the assumptions explained in Section Appendix A, are provided.

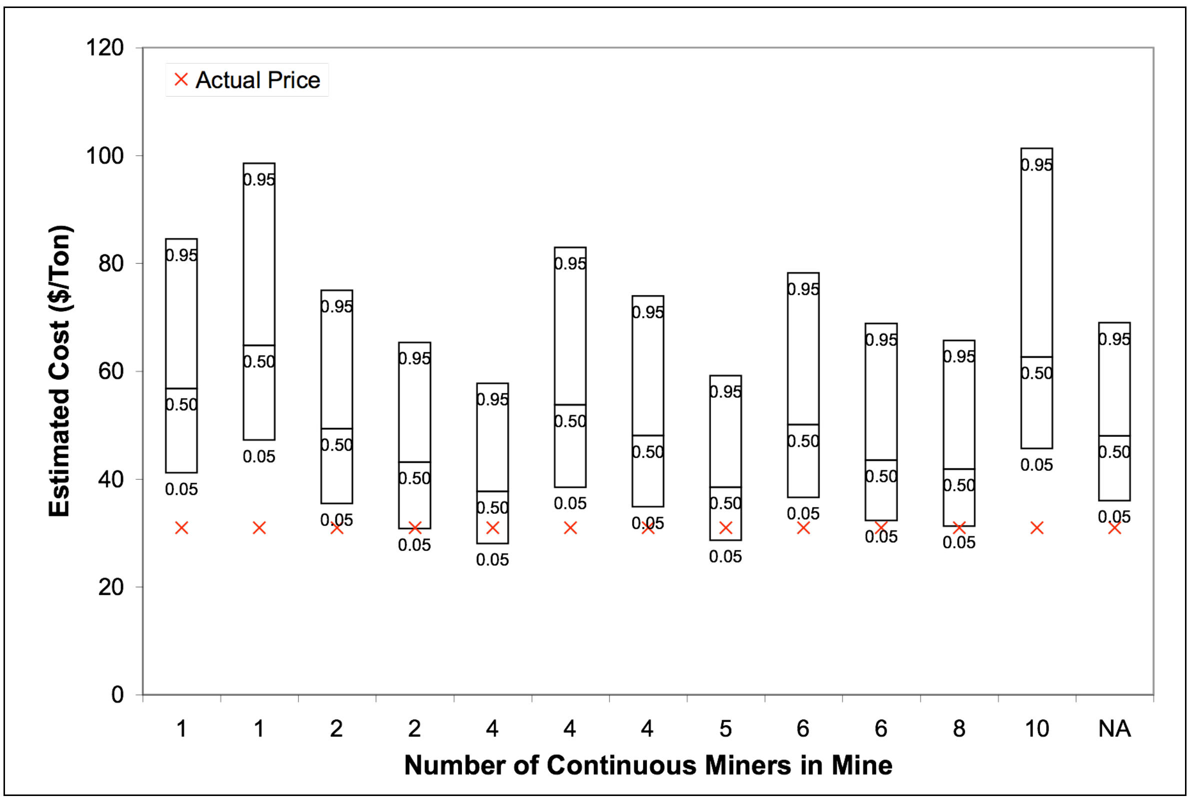

Figure 6 Comparison of actual and predicted continuous mining cost for known number of continuous miner units.

4.3.3 Comparison of longwall mine simulation results to real mine data

The number of longwall panels per each longwall mine is known and input to the model with the mine's coal resource characteristics. All of the two panel mines are located in seams that are approximately five feet thick. The model predicts the same mining rate for these mines, despite their location at different depths (Table 17). The construction of a longwall mine at any depth is the same. Gateway pillars in the development section are the same size regardless of depth, and panels are always of the same dimensions.

A comparison of price to predicted longwall mine costs is shown in Table 18. The same data are shown in Figure 7. The actual price always fell within the predicted range. The cost to price ratio, calculated by comparing the 50th percentile to the price shows that in most cases the estimated cost was less than the price, but in five cases, it was greater than the price.

Table 17. Relationship of Actual Longwall Production to Predicted Production Range for Known Number of Operating Panels. X indicates actual production within range.

Mine	Predicted Production, million short tons						Number of Longwall Panels	Actual Production
	5th		50th		95th			
Elk Creek	4.1	x	6.1		8.1		1	5.1
West Elk	5.9	x	7.6		9.1		1	6
Foidel Creek	3.4		4.5		5.5	x	1	8.6
Galatia	4.6		6.4	x	8.1		2	7.2
San Juan	4.7		6.3	x	8.5		1	7
Century	2		2.6		3.1	x	1	6.5
Powhatan	2		2.6		3.1	x	1	4.4
Bailey	5.2		7.1		9.2	x	2	10.2
Enlow	4.9		7.3		9	x	2	10.7
Cumberland	3		3.9		4.8	x	1	7.5
Emerald	2.5		3.4		4.1	x	1	5.9
Sufco	3.3		6.1	x	8.3		1	7.9
Dugout Canyon	2.8		3.5		4.3	x	1	4.4
Buchanan	2.2		2.9		3.4	x	1	5
McElroy	3.5		6.3	x	10.9		2	10.5
Loveridge	3.3		4.2		5	x	1	6.4
Robinson Run	3.1		4		4.8	x	1	5.7
Federal No 2	3.3		4.2	x	5		1	4.6

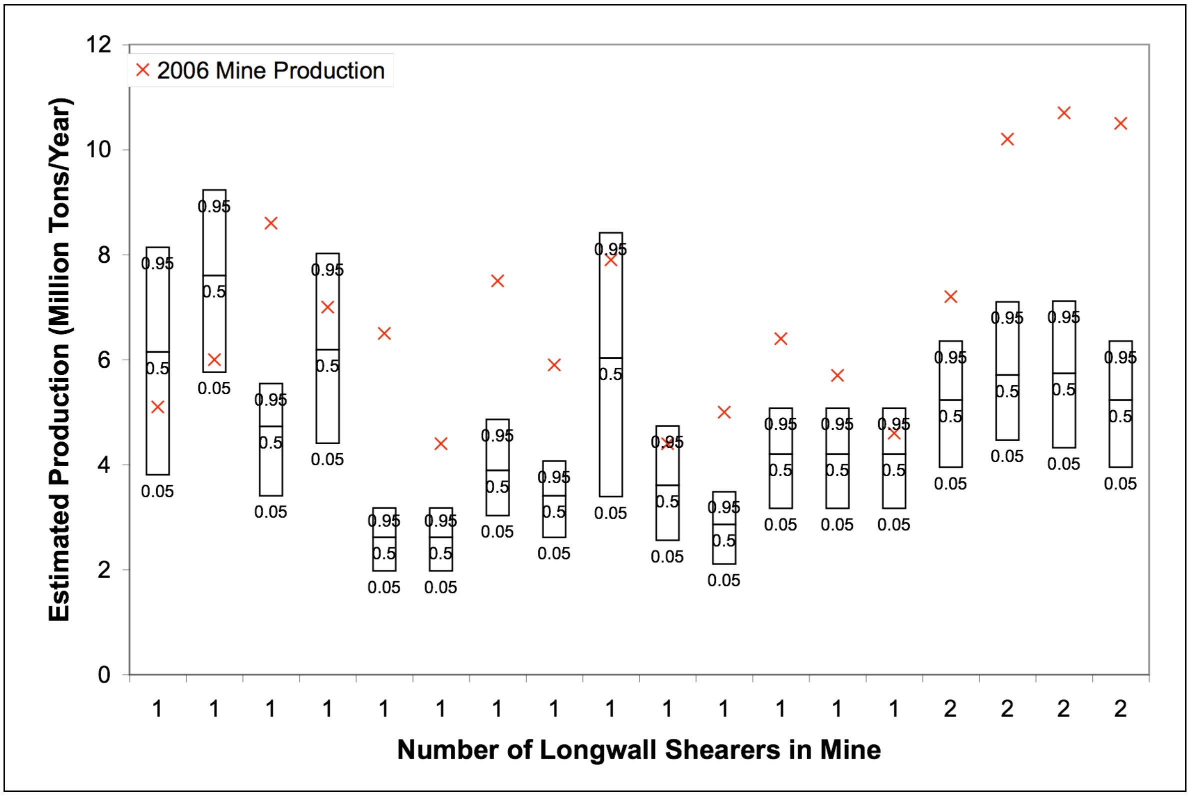

Figure 7 Comparison of longwall production to predicted range for knowng number of operating panels.

Longwall costs are represented accurately when the true number of longwall panels per mine are simulated. As shown in Table 18, the real price falls within the estimated cost range, close to the 50th percentile predicted cost. The same data is shown in Figure 8. When looking at cost estimate, the difference in seam depth is apparent. The deeper the mine for the same thickness seam, more money is spent, presumably on accessing the seam from the surface. Again, knowing the number of operating panels decreases the estimation uncertainty and range. The predicted range still captures the actual price.

Table 18. Relationship of Actual Longwall Coal Price and Predicted Longwall Cost. X indicates actual cost within predicted range.

		Predicted Cost ($/Ton)					
Mine	Actual Cost	25th		50th		95th	Cost-Price Ratio
Elk Creek	38.28	14		22	x	45	58
West Elk	24.1	13		23	x	166	96
Foidel Creek	24.1	16	x	26		64	108
Galatia	31.17	22	x	41		109	132
San Juan	29.15	13		21	x	47	72
Century	27.5	22	x	41		108	146
Powhatan	27.5	22	x	41		108	146
Bailey	37.4	21		37	x	100	100
Enlow	37.4	20	x	38		96	103
Cumberland	37.4	17		29	x	73	78
Emerald	37.4	19		32	x	76	86
Sufco	24.98	14		13	x	50	52
Dugout Canyon	24.98	20	x	32		70	128
Buchanan	52.99	22		39	x	84	74
McElroy	45.94	22		38	x	92	83
Loveridge	45.94	17		27	x	62	59
Robinson Run	45.94	17		28	x	63	61
Federal No 2	45.94	17		27	x	62	59

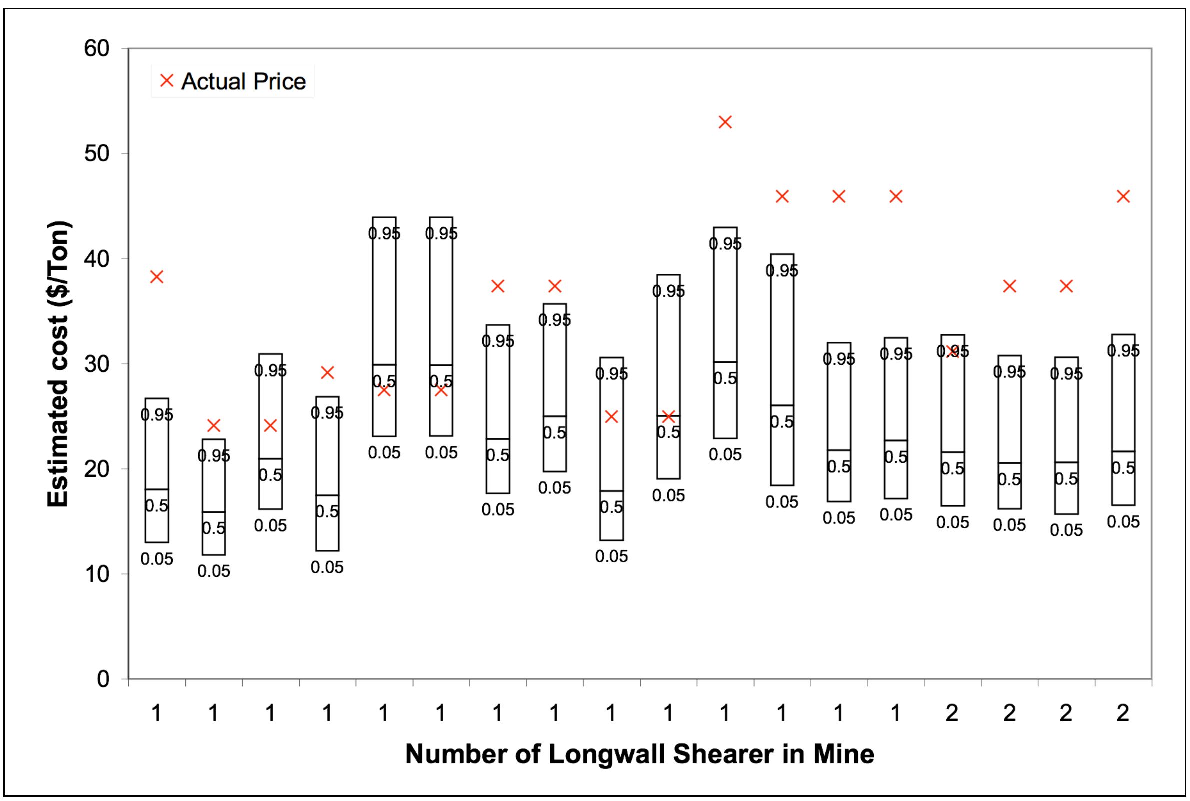

Figure 8 Comparison of actual longwall coal price and predicted longwall cost.

5 Discussion

The model was able to estimate a range of production costs and rates within 5 – 11 percent of historic prices and production rates. In many cases, the historic mine performance data did not fall within the 5^{th} and 95^{th} percentile estimates. The model, however, is suitable to simulate mine production and costs.

The model is sensitive to the input data. If the coal seam data is reported as a range, the uncertainty inherent in this information leads to tighter estimated cost ranges, but greater uncertainty in production rate estimates. In the case of surface mines, additional trucks and shovels are more costly in mines that have discrete definitions of thickness and depth. More accurate production estimates were achieved when known quantities of continuous miner units and longwall panels were simulated. However, specific configurations of surface mines were not available to complete a more detailed simulation.

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Chapter 3: Uncertainty of coal supply and cost to meet projected demand

1 Introduction

Coal accounts for 50 percent of our electricity production and 23 percent of our overall energy portfolio [1]. If coal is to remain a vital asset to our energy portfolio, we must understand how much it will cost (constant 2005 dollars) to produce. Chapter 2 describes a model that estimates surface and underground mine production and cost, based on geological characteristics of the coal seam to be mined. In this chapter, the model is applied to the National Coal Resource Assessment (NCRA) in order to determine the cost and recoverability of our known coal resource. The estimated costs and production rates are used to construct coal cost curves that illustrate the lowest cost method to meet demand projected by selected Energy Information Administration (EIA) energy technology cases.

The goals of this chapter are:

- Review the NCRA, which is our best estimate of available coal resources, to provide recommendations to improve its utility to energy planners,
- Estimate resource recoverability by NCRA region and coalfield per current mine technologies, to refine the estimate of available coal resource,
- Provide insight into longterm coal supply and cost to meet projected EIA demand by constructing resource cost curves.

This chapter begins with a discussion of the NCRA, EIA cases evaluated, and United States Geological Survey (USGS) efforts to understand long term coal resource availability. Next, the chapter describes how the NCRA data are input to the model to simulate production and costs per each region and coalfield. Finally, cost curves to supply at the lowest cost are constructed for each EIA coal demand case. The result of this analysis shows that available U.S. coal resource is 250 – 320 billion tons and that we could run out of coal if U.S. coal dependency increases, relative to expected business as usual demand, for electricity generation or liquid fuels.

2 Background

2.1 Energy Information Administration Coal Demand Cases

The Energy Information Administration (EIA) projects energy demand, supply, and prices each year in its Annual Energy Outlook (AEO). This forecast provides insight into future energy trends, based on energy policy scenarios. The four EIA forecast cases examined in this chapter are selected because they examine energy policy scenarios that affect coal demand for electricity generation. Their basic assumptions, as described in the AEO, and affect on coal demand are described, to identify the following energy efficiency and/or technology cost assumptions:

> **Reference**, which assumes no changes to current energy policy, technology innovation, and fuel availability. This is also referred to as "business as usual."
>
> **Integrated technology**, which assumes two possible cases of energy technology and efficiency. The first is called "2008 technology" because it assumes residential, commercial and industrial energy efficiency will not evolve beyond year 2008 performance, and will utilize expensive fossil, renewable, and nuclear energy. As a result, "2008 technology" is high coal demand case. The second technology scenario is called "integrated high technology" because it assumes that residential, commercial and energy efficiency will increase more than the business as usual case, and that fossil energy is expensive, but low nuclear and renewable energy are cheap. The "integrated high technology" case is a low coal demand case.
>
> **Fossil technology**, which evaluates two cases of fossil technology cost. The "low fossil cost case" is a high demand scenario. It assumes that natural gas and coal gasification combined cycle technology capital costs, heat rates, and operating costs are 10 percent lower than reference case levels in 2030. The "high fossil cost case" is a low demand scenario. It assumes constant year 2008 natural gas and coal gasification combined cycle technology capital costs and heat rates.
>
> **Energy supply, disposition, and emissions of natural gas cases**, which examines how natural gas supply and demand for electricity generation affect coal demand. There are three cases: "restricted natural gas supply," "restricted non-natural gas electricity supply," and "combined high demand and low supply." The first, "restricted natural gas supply," is a high demand case. It assumes that no Arctic natural gas pipelines will operate before 2030, constant year 2009 LNG import values. Additionally, compared to the reference case, it assumes 15 percent lower oil and gas resource availability, 50 percent less technological innovation. The second, "restricted non-natural gas electricity generation supply," is a low demand case. It mandates carbon capture and storage

technology for new coal-fired power plants. It places a priority on natural gas generation, so that non-natural gas technology costs are 25 percent higher than reference case costs. It also places restrictions on nuclear generation, forcing nuclear plant retirement when they are 40 years old. The third case, "combined limited supply and high demand," is also a low demand case. It combines the assumptions of the first two cases.

A regression analysis of selected EIA forecast cases (Appendix B) shows a linear relationship between the year (2006, 2010, 2020, and 2030) and estimated demand. The demand equations and their R-squared values are shown in Table 19.

Table 19 Coal demand equations, based on EIA forecast cases. x = year, y = coal demand (billion short tons)

EIA Forecast Case	Equation	R-squared	Cumulative 100-year demand (10^9 tons)
Reference	y=0.0176x-34.199	0.97	208
Integrated technology			
2008 technology	y=0.0264x-51.848	0.97	256
Reference	y=0.0176x-34.199	0.97	208
High technology	y=0.0127x-24.369	0.93	181
Fossil technology			
High fossil cost	y=0.0176x-34.299	0.97	198
Reference	y=0.0176x-34.299	0.97	198
Low fossil cost	y=0.176x-34.2	0.97	208
Natural gas			
Restricted natural gas supply	y=0.0133x-25.456	0.86	196
Reference	y=0.0088x-16.57	0.86	157
Restricted non-natural gas electricity generation	y=-0.0044x+1.085	0.86	103
Combined high demand and low natural gas supply	y=-0.0044x+1.085	0.86	103

The EIA projects a reference case per each forecast case in order to show relative change in demand. Reference case projections vary per EIA forecast case (Table 19). Later in this chapter, the "integrated technology reference case" is examined to provide insight into the cost to supply coal to meet business as usual demand. This reference case demands 208 billion tons of coal over 100 years.

As shown in Table 1, cumulative demand in a 2008 technology scenario will demand 50 billion tons (23 percent) more than the reference case, while the high technology case will demand (13 percent) 75 billion tons less than the reference case. The high fossil cost case and reference case demand the same amount of coal, but the low fossil cost case demands an additional 10 billion tons (5 percent). The natural gas demand cases are the most dynamic. The restricted natural gas case increases reference case demand by 60 billion tons (25 percent), while the restricted non-natural gas electricity generation and combined high demand and low natural gas supply cases reduce the reference case demand by 54 billion tons (34 percent).

2.1.1 Criticism of EIA forecasts

At best EIA energy forecasts provide a general estimate of future demand. The reference case forecasts vary from case to case (refer to Appendix B for data), but indicate that 2006 and 2010 demand is 1.1 – 1.2 billion tons of coal, 2015 demand is 1.2 – 1.3 billion tons of coal and 2030 demand is 1.4 – 1.5 billion tons. It is difficult to fit a trend line to the EIA coal demand scenarios in order to predict future coal needs. Demand projections have some uncertainty due to the imperfect trend line fit. The linear trend lines for the EIA data were not the best fitting, but output fit closest to the EIA calculated projection. Quadratic trend lines had a closer fit, but overestimated demand compared to EIA estimates.

2.2 National Coal Resource Assessment

This chapter estimates coal resource availability by using the USGS NCRA, the most complete U.S. coal geological dataset. It is a set of reports that summarize coalfield location, overburden depth, seam thickness, coal quality, and quantity. The USGS began the NCRA in 1999, out of the need to understand how much coal is available in the U.S. The NCRA inventories this data for the Colorado Plateau, Rocky Mountains and Great Plains, Northern and Central Appalachia, Illinois, and Gulf Cost coal regions. It excludes coalfields where there is no mining – namely, the Alaskan coalfields, the Western Interior basin, southern Appalachia, and part of the Gulf Coast region (Figure 9). It is believed that the five regions assessed will be the main coal source in the U.S [2].

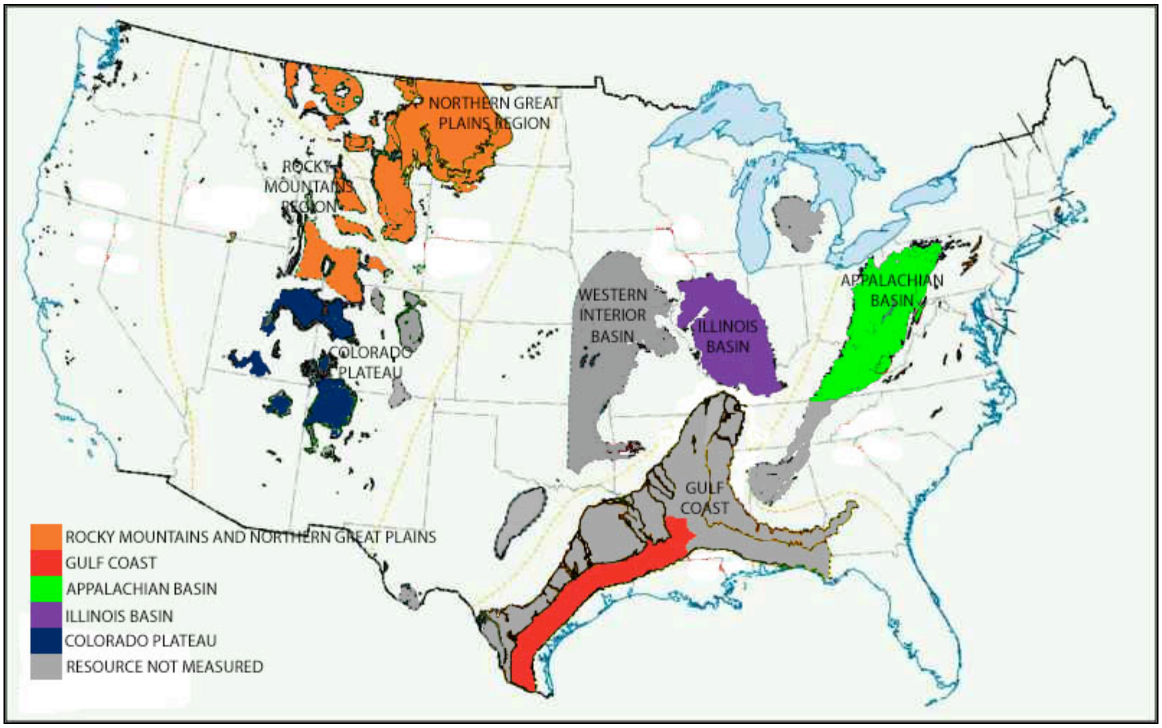


Figure 9 NCRA region map, based on USGS coal resource map, excluding Alaska. This figure is based on a 1996 USGS map of the U.S. coalfields [3].

The NCRA is a piecemeal effort undertaken by regional assessment teams, and still underway. The result of this fragmented approach is a set of coal region assessments that lack consistent certainty reporting, and seam thickness and depth categories. For example, overburden and thickness estimates for coalfields in the Powder River Basin are reported for depths up to 11,000 feet. In contrast, the Kittanning coal seam in northern Appalachia is simply described as "deeper than 700 feet." (See Appendix B for detailed comparison of regional data).

Without standard reporting and inclusion of all coal regions, coal resource estimates are uncertain. A 2007 National Academies of Sciences (NAS) report on U.S. coal resources [4] reported a range of total coal resources between 270 billion short tons of coal available in the EIA estimated recoverable reserves (ERR) to 490 billion short tons of coal available in the demonstrated reserve base (DRB). The DRB is comprised of the most reliably measured coal, in seams that are more than 28 inches thick and shallower than 1,000 feet. It is deemed commercially viable to produce. The ERR is a subset of the DRB. The EIA estimated the ERR by subtracting coal that lies under surface obstructions or unmineable by current methods from the DRB [5]. The NAS points to this range as proof that the availability of U.S. coal resources is not certain.

Additionally, the NAS report criticizes the selective NCRA coverage, and the lack of uncertainty in reported estimates. Moreover, it questions whether the data supports a "coherent national energy policy." Specifically, the NAS is unsure of the certainty that reported resource can provide 1.7 billion tons of coal to meet projected 2030 demand [6]. Furthermore, it asserts that we may be overconfident that coal resources will last 250 years as commonly believed. Clearer resolution of coal resources could be obtained if non-producing coal regions were added to the NCRA, and coal producer's resource surveys were accessed. The NAS claims that if the latter were publicly available, it would bolster data quality and quantity. Producer surveys are more detailed than USGS and state geological survey analyses [4].

In addition to expanding the NCRA to include all coal regions, its effectiveness can be improved by following existing USGS reporting guidelines. As a result, energy and resource planners would be able to estimate coal cost according to the seam thickness, depth, and data uncertainty. The data reporting standards, published in the USGS Circular 891 [7], that should be followed are:

Seam thickness and depth categories. These categories are intended as rules of thumb to determine whether it is more feasible to surface or underground mine the coal. On the basis of these defined categories, surface mining is not an option for mines more than 500 feet deep, whereas underground mining can be pursued at all depths (Table 20). Although the USGS defined mandatory overburden depth reporting categories, the categorical ranges vary throughout the NCRA reports.

Table 20. Mandatory and optional overburden and seam thickness categories defined by the USGS Circular 891 [7]	
Overburden depth	
Mandatory underground mining categories	Mandatory and optional surface mining categories
0-500 feet (0-150 m)	0-500 feet (0-100 m) mandatory use
500-1000 feet (150-300 m)	0-100 feet (0-30 m) optional use
1000-2000 feet (300-600 m)	100-200 feet (30-60 m) optional use
2000-3000 feet (600-900 m)	0-200 feet (0-60 m) optional use
3000-6000 feet (900-1800 m)	200-500 feet (60-150 m) optional use
Optional other occurrence category: >6000 feet (>1800 m)	
Thickness	
Anthracite and bituminous coal	Subbituminous coal and lignite
14-28 inches (35-70 cm)	2.5-5 feet (75-150 cm)
28-42 inches (70-105 cm)	5-10 feet (150-300 cm)
42-84 inches (105-210 cm)	10-20 feet (300-600 cm)
84-168 inches (210-420 cm)	20-40 feet (600-1200 cm)
168 inches or thicker (420 cm+)	40 feet or thicker (1200 cm+)

Data reliability categories. Coal resource samples are obtained by drilling the coalfield. The certainty of coal resource availability decreases as the distance between the sampling points increases. The NCRA categorizes resource "reliability," or the certainty and accuracy of its measurement, as "measured," "hypothetical," "identified," and "inferred." These terms describe the USGS confidence that a reported coal resource exists based on its distance from the sampling site. The EIA and the NAS follow these standards in their reports about coal resources.

The most detailed and "reliable" level of resource data are "measured," which means that the depth, thickness, and coal quality measurements are obtained from sampling points less than 0.5 miles apart. The amount of "measured" coal available is that which is known to be within 0.25 miles from the measurement site. On the opposite end of the spectrum, "hypothetical" coal resource is completely projected. This coal lies more than 3 miles from a sampling point and has not officially been discovered. Further exploration would establish whether it truly exists. In between these two extremes lie the "indicated" and "inferred" resources. "Indicated" resource estimates are based partly on measurements, partly on projection. This type of resource is projected to lie 0.25 – 0.75 miles from sampling points. "Inferred" resource estimates are mostly projected data based on assumptions about the coal bed's geology, and are projected to lie 0.75 – 3.0

miles from the sampling points. As previously mentioned, the DRB is comprised of the most reliably measured coal, "measured" and "indicated" coal. The DRB is also limited to seams more than 28 inches thick and less than 1,000 feet deep [8].

2.2.1 Coal resource available

As shown in the raw NCRA data tabulated in Appendix B, reported coal characteristic categories vary by region. They also vary by coalfield within a given region. Appendix B tabulates the thickness and overburden depth ranges per coalfield, and amount of coal reported per reliability category. The total raw data totals 976 billion short tons of coal. The data also shows that one-third of the reported resource is "inferred" and "hypothetical"; there are 457 billion short tons of "measured" coal, 157 billion short tons of "indicated" coal, 153 billion short tons of "inferred" coal and 165 billion short tons of "hypothetical" coal. The official USGS review of the nation's coal resources conclude that 2.24 trillion short tons of the 3.68 trillion ton coal resource inventory are classified as "undiscovered" or "hypothetical" [7].

3 Method

Longterm coal supply and costs are evaluated in this chapter. First, stochastic distributions of the NCRA coal seam thickness and depth data are input into the model that was described in Chapter 2. The model is used to generalize underground and surface mining costs and recovery rates in each NCRA coalfield. Next, the least cost mining method is assigned to each coalfield and the "recoverable supply" of coal in each NCRA coalfield is determined according to the corresponding mine recovery rate. The "recoverable supply" is the coal that can be extracted. Not all of the reported coal can be extracted. Some is left behind in surface pits or to support the layers of strata above an underground mine (Chapter 2). "Recoverability" is the proportion of "recoverable supply" to the total resource. After cost and recoverable supply are estimated for each coalfield, the coalfields are then scheduled according to lowest cost to meet estimated future demand per EIA forecast case.

The method outlined is similar to that used in the NCRA "Recoverable Coal Resource Assessment" (RCRA). The RCRA used the Coalval model (refer to Chapter 2 for more detail about the Coalval) to examine selected coalfield quadrangles[1] in the Illinois Basin [10] and Colorado Plateau [11]. The Illinois Basin study examined quadrangles in Illinois, Indiana, and Kentucky. The Colorado Plateau study examined quadrangles in Colorado, New Mexico, and Utah. Assuming that the quadrangles are representative of the entire coalfield or region, the NCRA estimates regional sale price and/or resource recoverability. An assessment of a seam in the Gillette coalfield (Rocky Mountains and Great Plains) is underway as well [12]. The Illinois Basin report evaluated the recoverability of Illinois coal. The Colorado Plateau report examined recoverability and breakeven sale price. The Illinois study estimated that 32 percent of the coal in the quadrangles was recoverable. The Colorado Plateau study estimated that recoverability ranged from 36 percent (Utah) to 75 percent (Colorado). The New Mexico recoverability rate was 60 percent. The study also estimated breakeven price for the Colorado and New Mexico coalfield quadrangles, which are $27/ton and $22/ton, respectively.

While the analysis in this chapter and the RCRA are similar, there are several important differences:

- Unlike the model used in this dissertation, the Coalval assumes that mine recovery rates are independent of seam depth. The Coalval prescribes recovery rates according to mine type and seam thickness, so that deep seams are as recoverable as shallow seams. This assumption is incorrect. Deep seams are most economically mined by underground methods. The deeper the seam is, the more coal that must be left behind in order to support the overlying strata for safety reasons.
- The RCRA estimates recoverability in small coalfield areas – selected quadrangles – while this chapter estimates recoverability for all NCRA regions. The Illinois study determines coal recoverability in 8 Illinois quadrangles, 3 Indiana quadrangles and 5 Kentucky quadrangles. The Colorado Plateau study determines recoverability in 1 Colorado quadrangle, 1 New Mexico quadrangle, and 1 Utah quadrangle.
- The RCRA studies are site specific, whereas this chapter analysis is not. In order to use the Coalval, the RCRA teams apportioned each quadrangle into "logical production units". A "logical production unit" is a mine in a contiguous area of

[1] A quadrangle is a rectangular or square area of land. In the U.S., a "7.5 minute" quadrangle is the standard "quadrangle," and is 49 – 70 square miles [9. United States Geological Survey. *Map Scales, Fact Sheet FS 105-02*. 2002 August 3, 2006 [cited 2008 November 20, 2008]; Available from: http://egsc.usgs.gov/isb/pubs/factsheets/fs01502.html..

coal that does not underlie an "unmineable" surface feature[2] and recovers 60 percent of its net present value (NPV) within 10 years [14]. Defining logical production units is labor and data intensive. Due to the desire to understand national resource recoverability and cost, the analysis in this chapter generalizes coalfield features. The result is less exact, but provides insight into resource availability and cost.

- The chapter produces coal cost curves, whereas the RCRA studies do not.

4 NCRA Data Input to model

Unlike the RCRA, which determined resource recovery and cost by assigning hypothetical logical production units to a study quadrangle, this analysis generalizes the seam thickness and depth of the entire coalfield in order to estimate a range of mining costs and production rates. As a result, the results of this analysis do not provide insight into mining a specific coalfield quadrangle. Instead, this analysis provides insight into the potential cost to produce coal in order to meet demand. The following discussion describes how the DRB (NCRA "measured" and "identified" resources) are evaluated.

Triangular distributions were assembled from the NCRA data. These distributions, rather than quadrangle-specific data, were used to represent coalfield geology. The NCRA organizes coal tonnage data by seam depth and thickness range category (see complete dataset used in Appendix B). As discussed in Section 2.2, the categories are inconsistent. Moreover, in some cases they are open-ended, which makes it difficult to estimate mining costs. If seam thickness is not certain, then the amount of coal in the seam and its production rate can't be estimated with certainty. If seam depth is not certain, then the amount of overlying strata and the cost to access the coal can't be estimated with certainty. Open-ended seam thickness and depth categories are defined throughout the NCRA (Table 21). As shown in Table 21, the amount of coal reported in these open-ended categories varies. The amount of coal in open-ended categories is most significant in Illinois, where in almost all cases more than 80 percent of the reported coal is 42+

[2] According to the Section 522 of the Surface Mining Control and Reclamation Act (SMCRA), surface features that can't be undermined are "fragile or historic lands," "renewable resource lands," "natural hazard lands," National Park land, national forests, and "any occupied dwelling, unless waived by the owner thereof," public buildings, schools, churches, cemeteries, and public parks [13. Office of Surface Mining, *Surface Mining Control and Reclamation Act of 1977*, United States Office of Surface Mining, Editor. 1977. p. 238..

inches thick or 150+ feet below ground. In contrast, less than 2 percent Appalachian coal was reported in open-ended seam thickness categories. However, the Appalachian coal depth reporting was less than satisfactory. Lower Kittanning coalfield resources were simply described as more than 700 feet deep, and no depth data was provided for the Pocahontas coalfield. In the western regions, Colorado Plateau and Rocky Mountains, the deepest seams were described by open-ended categories that were as deep as 10,000+ feet. Up to 40 percent of western coalfields' resource could be reported in an open-ended seam depth category, and up to 90 percent in an open-ended seam thickness category.

Table 21 Open-ended category reporting by NCRA coalfield. Amount of coal reported by depth or thickness is mutually exclusive.

NCRA Region	Coalfield	Open-ended category	Amount of coal reported in category (million tons)	Percent of total coal resource
Colorado Plateau	Deserado	14+ feet thickness	31	8
		1000+ feet depth	75	21
	South Piceance	14+ feet seam thickness	37,000	26
		10,000+ feet seam depth	8,200	6
	Yampa	14+ feet seam thickness	4,500	90
		3,000+ feet seam depth	80	2
	Henry Mountains	10+ feet seam thickness	610	54
	San Juan	14+ feet seam thickness	203,100	95
		3,000+ feet seam depth	85,400	40
Rocky Mountains and Great Plains	Hanna-Hanna 77, 78, 79, 81	2000+ feet seam depth	520	49
	South Carbon	40+ feet seam thickness	40	5
		500+ feet seam depth	240	29
Appalachia	Pittsburgh	14+ feet seam thickness	50	1
	Lower Kittanning	3.5+ feet seam thickness	350	1
		700+ feet seam depth	26,600	100
	Fire Clay	7+ feet seam thickness	100	2
	Pond Creek	7+ feet seam thickness	50	1
Illinois	Springfield	42+ inch seam thickness	26,300	93
		150+ feet seam depth	25,100	87
	Herrin	42+ inch seam thickness	50,800	90
		150+ feet seam depth	48,300	88
	Danville	42+ inch seam thickness	7,200	42
		150+ feet seam depth	13,800	81

The data are "normalized" by truncating the DRB resource depth and thickness. Because the data are assessed exclusively by depth or thickness, it is necessary to sort it by one category before evaluating it by the other category. The available coal is quantified by truncating the DRB dataset to exclude coal reported at depths more than 1,000 feet. By eliminating coal that is in seams more than 1,000 feet deep, most of the western coalfield depth uncertainty is resolved. The choice of a maximum 1,000 feet seam depth is also suitable in the Illinois basin, where coal has been measured at depths up to 1,500 feet [15]. The minimum depth is the low end of the minimum depth range per each coalfield. The depth mode in each coalfield is assumed to be the median depth. To assign minimum, mode, and maximum seam thickness, it is assumed that the proportion of coal in each thickness category remains the same after excluding coal that is more than 1,000 feet deep.

The triangular distributions based on minimum, mode, and maximum thickness and depth, as described above, are shown in Table 23. 333 billion tons of the DRB are evaluated. Four coalfields – the Danforth Hills and Deserado in the Colorado Plateau, and Hanna-Ferris and Hanna-Hanna in the Rocky Mountains and Great Plains – have multiple seams that interlay one another. The model can simulate surface mining in these coalfields, but not underground mining because there are multiple seams. Underground mining cost and production are not simulated for these four seams, but that does not mean that they can't be mined by longwall or continuous mining methods. The uncertainty resulting from manipulating the NCRA data to input it to the model, and model application are further discussed.

Table 22 Triangular distributions of seam characteristics input to model. The mode is the average value of the category range that has the most reported coal. The minimum is the low end of the minimum category range. The maximum is the high end of the maximum category range.

Region	Coalfield	Thickness, feet (min, mode, max)			DRB overburden, feet (min, mode, max)			Coal (10^9 Tons)
Colorado Plateau	Danforth Hills	2.5	160	410	0	250	1000	12.1
		3.7	210	310	0	250	1000	
		7.5	280	500	0	250	1000	
		3.5	120	250	0	250	1000	
		12	115	195	0	250	1000	
		6	110	230	0	1000	1000	
		8	130	280	0	1000	1000	
	Deserado	1.2	10.5	14	0	250	1000	0.3
		1.2	10.5	14	0	250	1000	
	South Piceance	1	10.5	14	0	800	1000	7.0
	South Wasatch	7	14	14	0	1000	1000	1.2
	Yampa	1.2	10.5	14	0	1000	1000	1.5
	Henry Mountains	2	10	10	0	550	1000	1.1
	San Juan	1.2	14	14	0	1000	1000	24.7
Rocky Mountains and Great Plains	Ashland	2.5	25	100	84	1000	1000	3.7
	Colstrip	2.5	15	40	0	375	1000	4.8
	Decker	2.5	75	150	0	0	1000	17.4
	Gillette	2.5	75	200	0	750	1000	59.9
	Sheridan	2.5	75	150	0	750	1000	6.1
	Williston-Beulah-Zap	2.5	15	40	0	350	500	2.7
	Williston-Hagel	2.5	15	40	0	50	500	3.3
	Williston-Hansen	2.5	7.5	40	0	350	500	2.0
	Williston-Harmon	2.5	15	40	0	350	500	5.4
	Hanna-Ferris 23, 25,31,50,65	2.5	7.5	20	0	1000	1000	0.3
		2.5	7.5	30	0	350	1000	
		2.5	7.5	30	0	750	1000	
		2.5	15	30	0	1000	1000	
		2.5	7.5	30	0	750	1000	
	Hanna-Hanna 77,78,79,81	5	45	100	0	1000	1000	1.3
		2.5	35	50	0	1000	1000	
		2.5	35	40	0	1000	1000	
		2.5	35	40	0	1000	1000	
	Carbon-Johnson	2.5	40	40	0	50	500	0.8
	Green River-Dead Man	2.5	25	40	0	350	1000	0.4
Gulf Coast	Wilcox	1.5	3.75	40	0	50	500	3.5
	Lower Wilcox	1.5	3.75	40	0	150	500	0.6
Appalachia	Pittsburgh	1.17	5.25	14	0	100	1000	11.6
	Upper Freeport	3.5	7	14	0	250	1000	24.6
	Lower Kittanning	1.17	2.89	3.5	700	1000	1000	26.6
	Pond Creek	1.17	4.41	14	0	750	1000	8.2
	Fire Clay	1.171	5.25	14	0	350	1000	5.1

Table 22, continued									
NCRA Region	Coalfield	Thickness, feet (min, mode, max)			DRB overburden, feet (min, mode, max)			Coal (10^9 Tons)
Appalachia	Pocahontas[a]	1.17	5.25	14	0	1000	1000	5.1
Illinois	Springfield	1.2	3	4	0	325	1000	28.3
	Herrin	0	3.5	10	0	325	1000	54.5
	Danville	1.2	2.8	4	0	325	1000	13.3

[a]Pocahontas coalfield depth and overburden categories are not reported because it is deemed “too thin and too deep to be mined under economic and technological conditions as of 1999” [18]. This analysis assumes that seam the Pocahontas coalfield has the same thickness as the neighboring Fire Clay coalfield, and that its mode and maximum depth are 1,000 feet.

4.1 Uncertainty related to the NCRA

This analysis provides a low estimate of available coal resource. To begin with, the NCRA does not quantify all coal resources. As previously discussed, the NCRA evaluates coal in the regions believed to be the main U.S. coal source. Therefore, the reported resource in this analysis is low. Excluding coal resource that is more than 1,000 feet deep further diminishes the NCRA data. There is some uncertainty related to the amount of coal in Illinois and Appalachia that is more than 1,000 feet deep. In these regions, some of the coalfields provide de minimus coal seam depths (see Appendix B). However, as mine technology improves, it is likely that coal deeper than 1,000 feet deep can be safely and economically accessed. Truncating available resource at 1,000 feet deep provides a low estimate of available coal, but provides insight into available coal resource that meets the DRB definition.

4.2 Caveats to applying the model

The model has several limitations that result in low estimated cost to mine NCRA coal. First, estimated recovery is optimistic because the model assumes that coal seams are uniformly distributed throughout a coalfield. The model assumes that there are no interruptions in the coal seam, so that coal is contiguous and may be mined by optimally sized mines. The model assumes that these mines are optimally distributed with no obstructions such as physical barriers that prohibit their development, oddly shaped coalfields, or any safety complications that would keep them from operating under current mine hazard regulations. Second, the model assumes perfect operating conditions. As mentioned in the first limitation, the model assumes that there are no conditions at the minesite that will cause safety disruptions such as unstable geology or abandoned minesites neighboring the new site that could cave in or otherwise present challenges to the modeled mines. Although some delays are built into the model that account for equipment rearrangement, configuration and maintenance (Chapter 2), extended production delays are not represented. These delays could result from the aforementioned safety hazards, challenging terrain, or change in demand. Third, the model only estimates surface mining costs for NCRA coalfields that report coal availability in multiple seams. Surface mine recovery is higher than underground mine recovery, resulting in a low cost estimate for those coalfields. As a result, the analysis provides a low estimate of mining cost in those coalfields and the estimated range of cost in those fields is low. Fourth, the model assumes that coal mining and resource planning will be an optimized process where the cheapest mines will be schedule to supply demand regardless of their location relative to demand. In reality, the decision to purchase coal from a given region is related to its transportation cost. According to an EIA report on coal transportation rates and trends, transportation costs for Appalachian, Illinois, Powder River Basin, and Rocky Mountains coal are $7-$10/ton, $6/ton, $12/ton and $19/ton[3], respectively [17]. No transportation cost data are available for the Gulf Coast and Colorado Plateau regions. The transportation costs reported above play a role in the decision to purchase coal from one region over another. Fifth, the model assumes that all U.S. coal resource is equal. It does not consider coal heating value or sulfur content, though these qualities determine demand for coal. In all, the analysis described in this chapter provides a low estimate of coal mining costs because it assumes optimal mining conditions and negates factors that affect coal demand and sales price, such as transportation costs and coal quality. The result is the cheapest cost to supply coal, if U.S. resource is optimally developed as the model anticipates.

[3] These costs are inflated from 2000$ to 2005$ by using the consumer price index reported by the Bureau of Labor Statistics 16. Bureau of Labor Statistics. *Consumer Items Indexes and Annual Percent Changes from 1913 - Present*. 2007 [cited 2008 November 24, 2008]; Available from: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

In reality, there are several coalfields or regions throughout the U.S. that provide coal at any given time. Coal supply infrastructure already exists to extract and transport coal from the coalfield to demand centers. Coal is currently mined throughout the U.S., independent of this analysis. This analysis assumes greenfield mine development and systematic extraction under ideal conditions. It should be understood that this evaluation optimizes coal resource extraction without considering coal quality or location.

5 Adjusted resource availability

A resource's availability is dependent on its recoverability. Thus, the reported available resource per coal seam is adjusted to reflect the amount of coal that can be recovered by the least cost method:

$$AdjCR_i = r_{i,j} \times CR_i \qquad (1)$$

where $AdjCR_i$ = adjusted resource for coalfield i (million short tons)
$r_{i,j}$ = recovery rate of mine type j in coalfield i (percent), shown in Figure 10
CR_i = coal resource reported by the USGS NCRA (million short tons), shown in Figure 11

The model estimates recovery rate by comparing the amount of coal that can be extracted by longwall, continuous, and surface mining to the original amount of coal. The estimated recovery rate per region, r, is shown in Figure 10. Appendix B contains all detailed model output, estimated 5th – 95th percentile recovery rate for each coalfield.

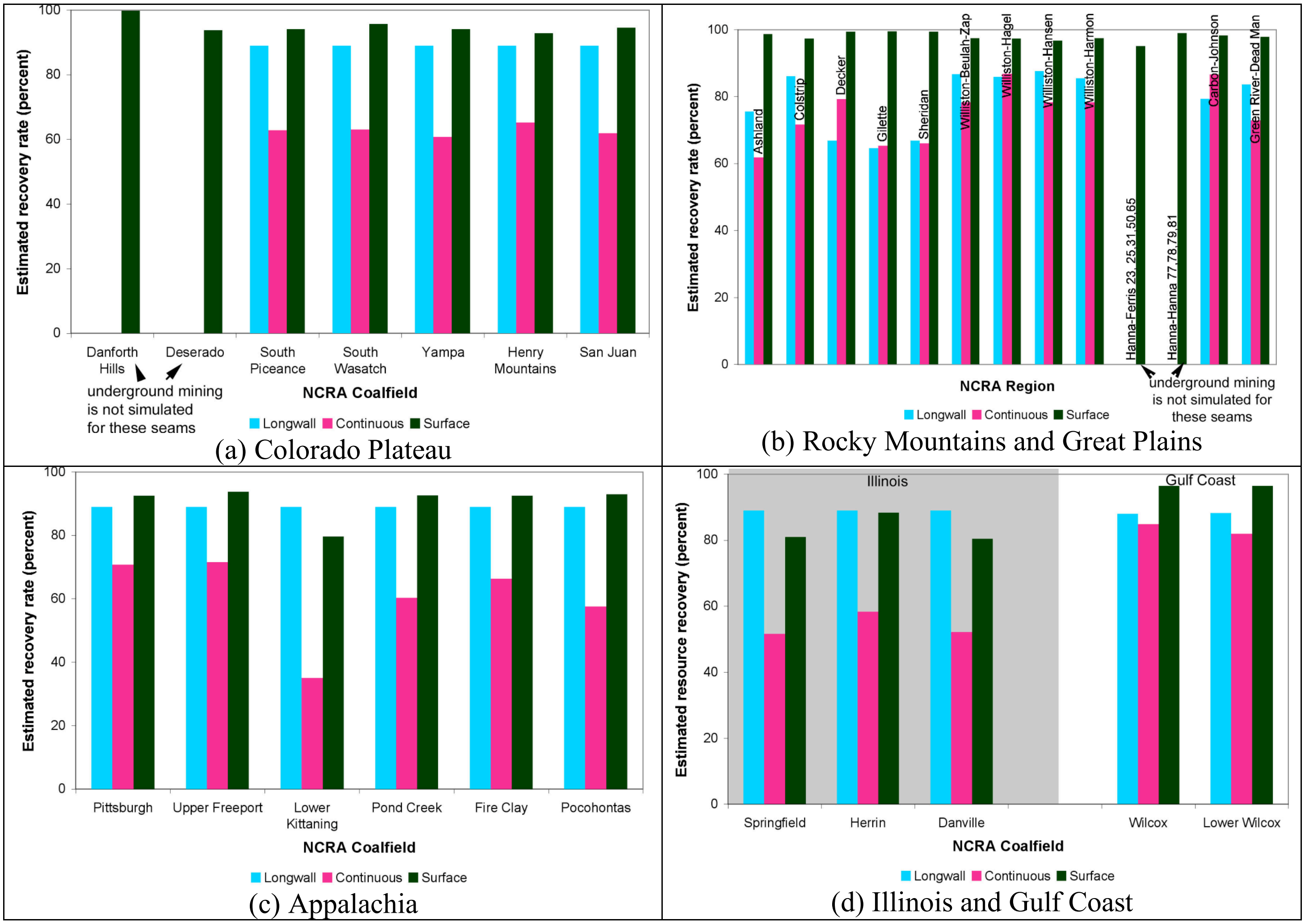


Figure 10 Median estimated coal recovery rate, *r*, by mining method and NCRA region. Complete 5th, 50th, and 95th percentile estimates are available in Appendix B.

As shown in Figure 10, surface mines have the highest recovery rates (83 – 98%), and continuous mines have the lowest (54 – 83%). Longwall mines have the smallest recovery rate range (78 – 89%), while continuous mines have the largest range of estimated recovery. Continuous mines have the lowest recovery rates because they must leave pillars of coal to support the overlying strata. Pillar size increases as seam depth and thickness increase, so they will vary with geological characteristics. As shown in Figure 10, estimated continuous mine recovery rates are lowest in the Appalachian and Illinois regions (Figure 3c, 3d) because the coal seams are thinnest and deepest there. Unlike continuous mining, longwall mining is consistently sized regardless of seam depth because it does not need to leave coal pillars to support the overlying strata. Except for simulated mines in the Rocky Mountains and Great Plains (Figure 10a, 10b), estimated longwall recovery rates are consistent per each NCRA region. The estimated variation in the Rocky Mountains and Great Plains is due to the greater range of coal seam thickness in the region. For example, Gillette seam thickness is 2.5 – 200 feet, but the Colstrip seam is 2.5 – 40 feet. Due to the limitations of modern underground technology, which are no taller than 8 feet, a lower percentage of Gillette seam coal will be recovered than Colstrip coal. In contrast to longwall and continuous mining methods, surface mine recovery is not limited by equipment size or seam characteristics. Estimated surface mine recovery is only limited by the overburden removal time, that is the time that it takes to access coal from the surface. Therefore, estimated recovery rates are lower in deep seams, such as those in Appalachia and Illinois (Figure 3c, 3d).

The coal resource, CR_i, is the amount of coal per NCRA coalfield that included in this analysis (see Table 22). As shown in Figure 11, the Gillette (Rocky Mountains and Great Plains) and the Herrin (Illinois) seams have the most coal. Deserado, South Wasatch, Yampa, and Henry Mountains seams in the Colorado Plateau, and Carbon-Johnson, Green River, and Williston and Hanna coal seams in the Rocky Mountains and Great Plains have the available least coal.

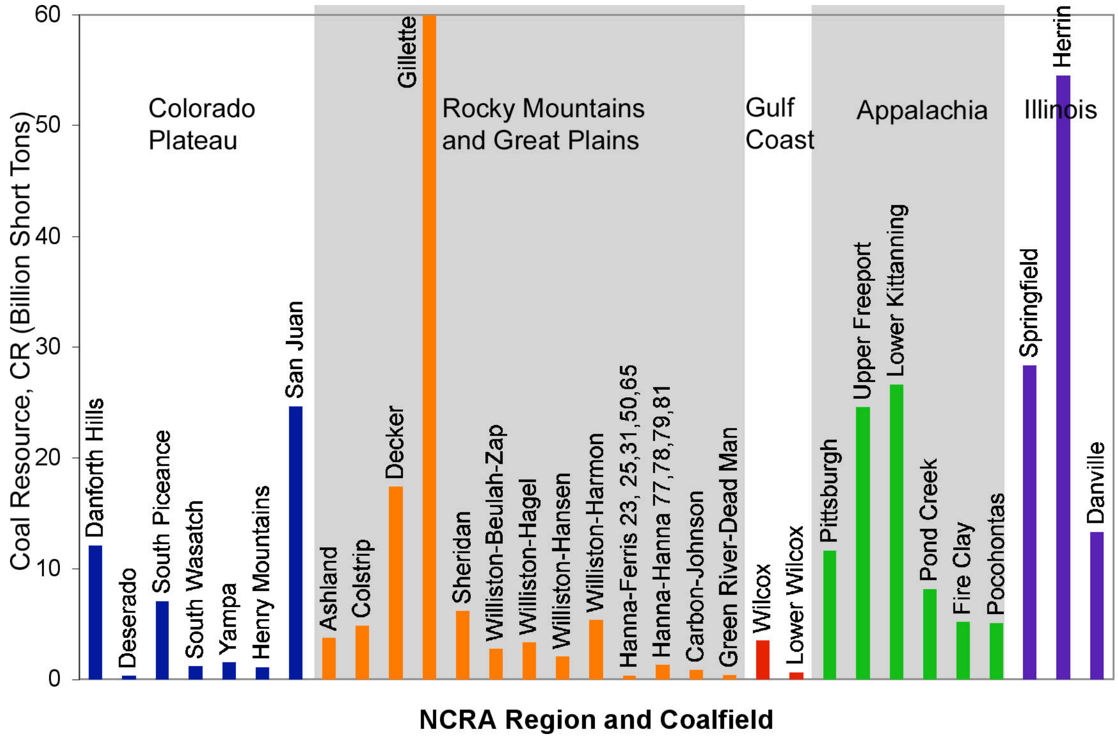


Figure 11 Coal resource reported by the USGS NCRA, *CR*.

The median estimated adjusted coal resource (*AdjCR*) is shown in Figure 12. These estimates show the range of coal available per region, based on extraction method. In the western NCRA regions (Colorado Plateau and Rocky Mountains and Great Plains), surface mining will recover the most coal because it has the highest recovery rate. In the eastern coal mining regions (Appalachia and Illinois), longwall mining will recover the most coal. In practice, a mix of surface and underground mining would be used to extract the resource, but it is advisable to select surface or longwall mines to recover as much of the reported coal resource as possible.

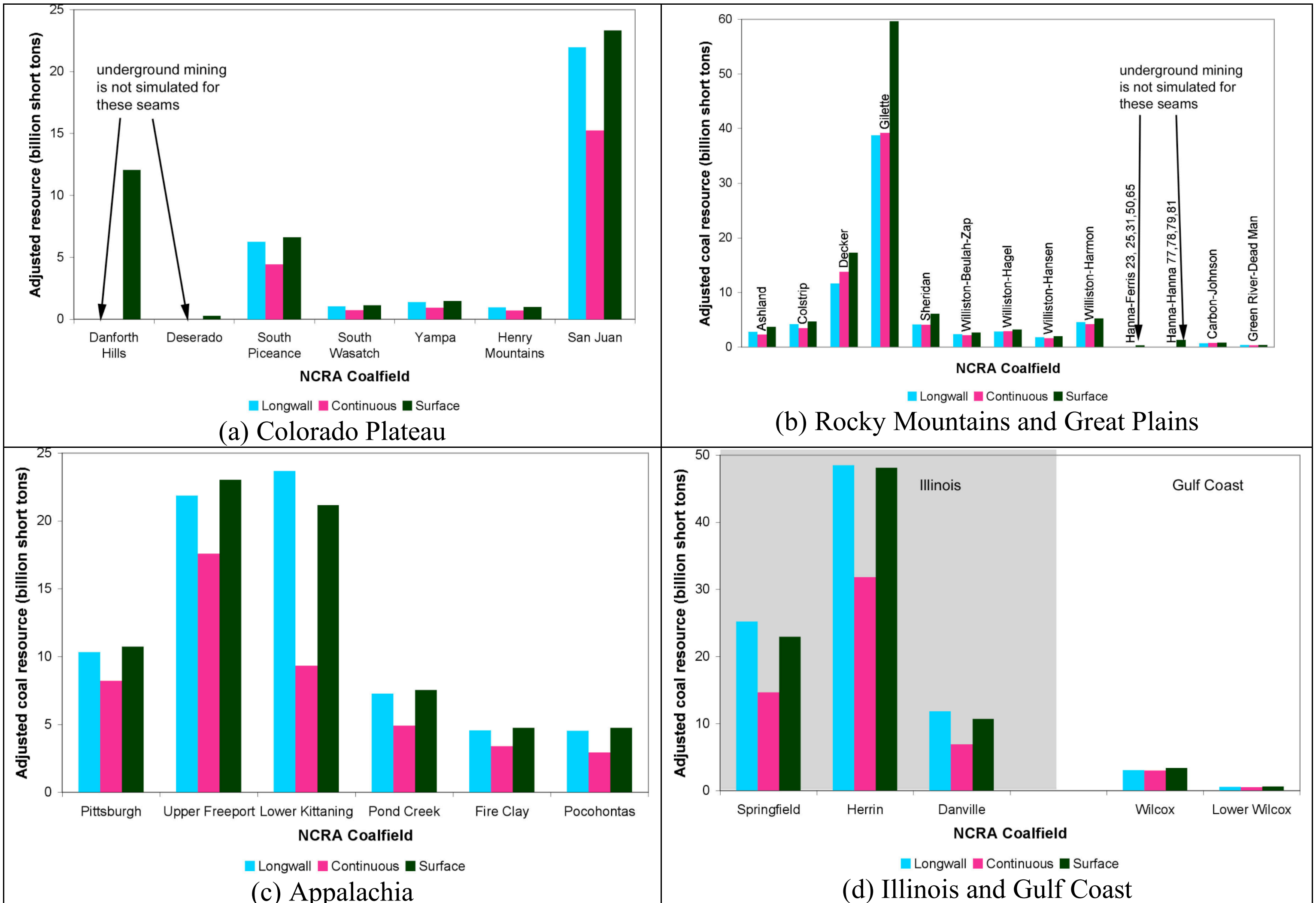
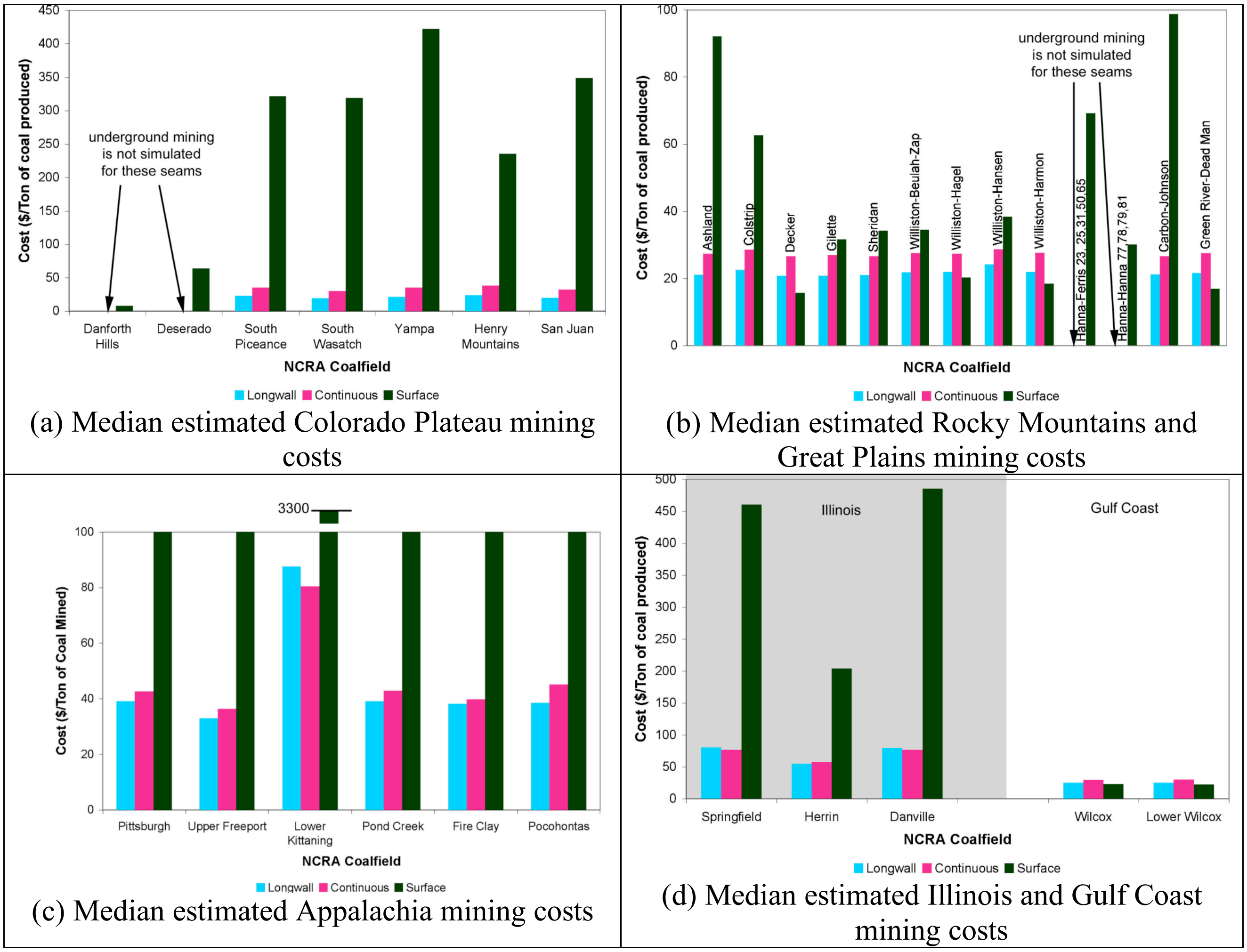


Figure 12 Median estimated adjusted coal resource (*AdjCR*) per coalfield and region. Complete 5th, 50th, 95th percentile estimates are shown in Appendix B.

6 Estimated mining costs

The estimated mining costs in each coalfield are tabulated in Appendix B. The median cost to mine by underground and surface mining method are compared in Figure 13. Median longwall mine costs were the lowest in most coalfields, ranging from \$21 - \$28/ton of coal in the western coal regions (Figures 13a and 13b), and \$25/ton in the Gulf Coast (Figure 13d). In these regions, estimated continuous mining cost is about \$5/ton more expensive. Longwall mine cost is comparable to continuous mine cost in Illinois, where it would cost \$55 - \$80/ton to underground mine. In Appalachia (Figure 13d), it will cost \$5 more per ton to continuous mine than longwall mine in all coalfields except the Lower Kittanning coalfield. Estimated mining costs in the Lower Kittanning are the highest because the minimum seam depth is 700 feet. It will cost $3300/ton to surface mine coal in the Lower Kittanning coalfield, which is more than five times the estimated surface mining cost in the deep Illinois coalfields (Figure 5d). Overall, median surface mining cost is higher than underground mining cost.

High estimated surface mining costs may seem counterintuitive, as surface mines accounted for 51 percent of the 2006 coal mine population [19]. Therefore, one expects that surface mining costs would be competitive with underground mining costs. However, the estimated median surface mining costs are high because it represents the cost of mining an average section of the coalfield. As shown in Table 22, the mode depth in most coalfields is more than 300 feet. As a rule of thumb, most resource planners assume that it is more cost efficient to use underground mining methods to extract resources that are more than 300 feet below the surface [20]. Cost to surface mine the coalfield between the minimum and mode depth is best captured by the 5th percentile cost estimate. The 5th percentile surface mine cost ranges from $4 - $52/ton in the Colorado Plateau, $5 - $16/ton in the Rocky Mountains and Great Plains, $15 - $49/ton in Appalachia (except for the Lower Kittanning seam, where 5th percentile estimated cost is $1120/ton), $32 - $49/ton in Illinois, and is $7/ton in the Gulf Coast (see Appendix B for model output.) In practice, surface mines would be used to extract shallow resources for the 5th percentile estimated cost. The 5th and 95th percentile estimated costs are briefly discussed, but only 50th percentile costs are discussed and compared in the analysis of alternative EIA demand forecasts.



(a) Median estimated Colorado Plateau mining costs

(b) Median estimated Rocky Mountains and Great Plains mining costs

(c) Median estimated Appalachia mining costs

(d) Median estimated Illinois and Gulf Coast mining costs

Figure 13 Median estimated mining costs (2005$) per NCRA region and mine type.

Having estimated the lowest 5th, 50th, and 95th percentile estimated cost for each coalfield, the coalfields are scheduled in order of least cost. The order of least cost extraction is shown in Table 23, where the coalfields are distinguished by their region. The 5th percentile cost is associated with the 5th percentile thickness and depth; it is the cost to extract the thinnest and shallowest portions of the coalfield. The 50th percentile cost is the median cost, that is, the cost to extract the mode depth and thickness coal seams. The 95th percentile cost is the highest cost, and is the cost to extract the thickest and deepest coal resource. Mining methods and expected resource recovery reflect the seam thickness and depth distributions. In most regions, surface mines are the cheapest coal source. Surface mining is the dominant least 5th percentile cost method. Surface mining is supplemented by more longwall mining to provide coal at the 50th percentile cost estimate, and continuous mining provides the bulk of coal at the 95th percentile cost.

Based on estimated resource recovery, median resource recovered is 250 billion tons. The 95th percentile resource recovered from all regions is 320 billion tons, and the 5th percentile resource recovered is 280 billion tons. The 5th percentile resource recovered is higher than the 50th percentile resource recovered because surface mine recovery rates are higher than longwall mine recovery rates.

Table 23 Least cost, mine type, and adjusted coal resource per region. The lowest 5th, 50th, and 95th percentile cost (2005$) estimates per each region are ranked in order to create least cost curves.

5th Percentile				50th Percentile				95th Percentile			
Region	Mine Type	Cost ($/Ton)	Adjusted Coal Resource (10^6 tons)	Region	Mine Type	Cost	Adjusted Coal Resource (10^6 tons)	Region	Mine Type	Cost	Adjusted Coal Resource (10^6 tons)
C	SM	4	11984	C	SM	8	12047	C	SM	13	12067
R	SM	5	17039	R	SM	16	17260	R	LW	29	6131
R	SM	6	386	R	SM	17	402	R	LW	29	59809
R	SM	7	3063	R	SM	18	5222	R	LW	31	3710
R	SM	7	2998	R	SM	20	3224	R	LW	31	17330
R	SM	7	4943	R	LW	21	38732	R	LW	34	829
G	SM	8	555	R	LW	21	4108	R	CM	36	407
R	SM	9	1253	R	LW	21	2810	R	CM	39	4807
R	SM	9	58984	R	LW	21	662	R	CM	40	2701
R	SM	9	5977	R	LW	22	2367	R	CM	41	5312
R	SM	10	2535	G	SM	22	614	C	LW	41	1159
R	SM	11	1828	R	LW	23	4167	R	CM	42	3285
R	SM	11	796	G	SM	23	3382	R	CM	52	2017
C	SM	12	238	R	LW	24	1787	C	CM	58	24235
R	SM	13	4489	C	LW	25	1049	A	CM	58	23924
R	SM	14	281	C	LW	28	21944	C	CM	66	1037
A	SM	15	9050	R	SM	30	1281	G	CM	66	631
A	SM	15	21452	C	LW	31	6265	C	CM	68	6909
A	SM	15	4049	C	LW	31	1374	C	CM	68	1510
R	SM	16	3577	A	LW	33	21844	G	CM	73	3470
C	LW	19	1033	C	LW	35	945	A	CM	84	7910
C	LW	20	21596	A	LW	38	4577	A	CM	87	11307
C	LW	21	1352	A	LW	39	7253	A	CM	94	4993
C	LW	23	6166	A	LW	39	10317	R	SM	95	1289
A	LW	24	7138	I	LW	55	48472	I	CM	133	12379
C	LW	24	930	C	SM	64	266	I	CM	133	26267
I	LW	28	47703	R	SM	69	301	I	CM	150	24410
I	SM	44	18517	I	CM	76	14630	I	CM	197	52407
I	SM	49	8715	I	CM	76	6921	R	SM	262	311
A	CM	57	8757	A	CM	80	9329	C	SM	400	278
Total Available			280,000				250,000				320,000

Coal regions are abbreviated: C = Colorado Plateau, R = Rocky Mountains and Great Plains, G = Gulf Coast, A = Appalachia, I = Illinois.
Mine types are abbreviated: SM = surface mine, LW = longwall mine, CM = continuous mine

6.1 Resource cost curves

The cumulative resource cost curve is shown in Figure 14. It shows the 5th, 50th, and 95th percentile available resource and related cost. Each step in the 5th, 5th, and 95th percentile cost curves shows the next cheapest resource available and mining method. As previously stated, the 5th percentile recoverable resource is 280 billion tons of coal, the 50th percentile resource is 250 billion tons of coal, and the 95th percentile resource is 320 billion tons of coal. Figure 14 shows that the 5th percentile cost is less than \$3/mmBTU, 50th percentile cost is less than \$4/mmBTU, and more than two-thirds of 95th percentile coal cost is less than \$10/mmBTU, with a maximum cost of \$20/mmBTU. The 5th percentile cost curve shows that surface mines provide most of the cheapest coal, with some longwall mines and one continuous mine providing low cost coal. The 50th percentile curve shows that longwall mines are the dominant mining method for median cost coal, and the 95th percentile curve shows that continuous mines will provide the most of the expensive coal.

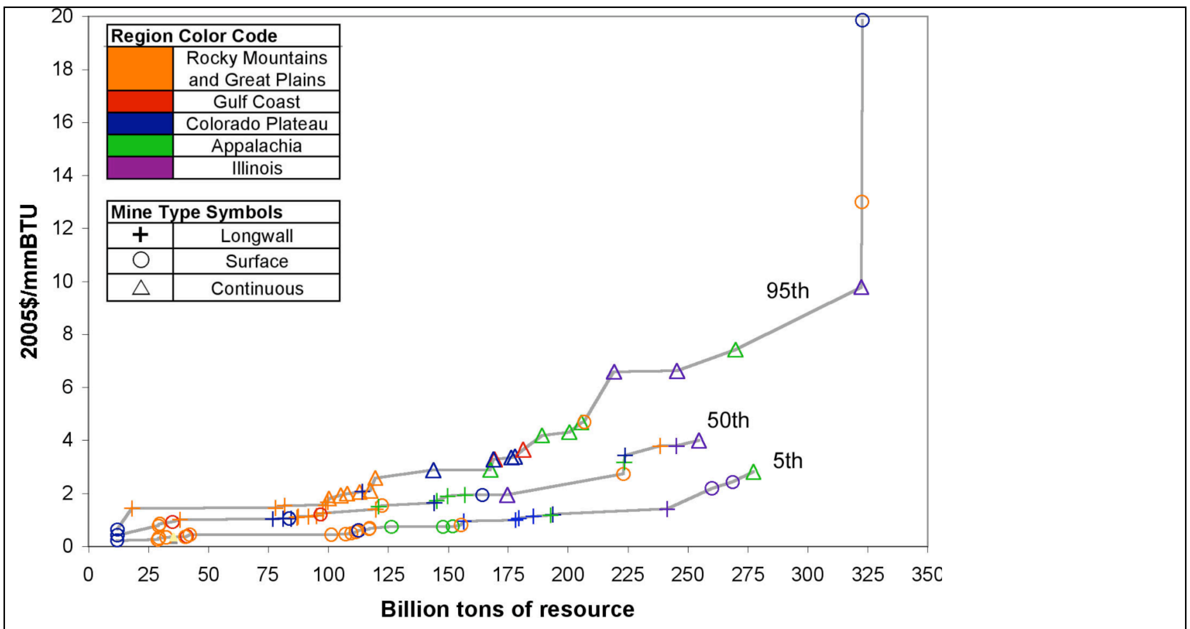


Figure 14 Mining cost to mine coal resource by region and mine type. Based on 2007 consumption data, it is assumed that coal heating content is 20 mmBTU per ton [21]. To estimate total cost to supply coal to a power plant, transportation costs may be added. Rocky Mountains and Great Plains coal transportation costs are \$0.6-\$1/mmBTU, Illinois coal transportation costs are \$0.3/mmBTU, Appalachia coal transportation costs are \$0.4-\$0.5/mmBTU [17]. No transportation cost data is reported for the Gulf Coast and Colorado Plateau in the EIA coal transportation study.

6.1.1 Cost to meet projected demand

The least cost curve to meet the EIA reference case is shown in Figure 15. It evaluates a 100-year period. A time period of 2010 to 2110 is chosen as an illustrative example, but the 100-year period evaluated could start in any year of interest. It should be understood that the years discussed in this section are for illustrative purposes only, assuming that the model's optimization of coal resource development under ideal conditions were to start in 2010. It shows that mines in the Colorado Plateau and Rocky Mountains and Great Plains will provide most of the cheapest coal through 2080. The cost is less than \$15/ton before 2020. From 2020 to 2070, the cost ranges from \$10 - \$30/ton, and from 2070 to 2080 it will increase so that 95th percentile costs in 2080 are \$52/ton. The 5th percentile cost curve indicates that the pre-2080 coal will be surface mined, the 50th percentile curve shows that it will be surface and longwall mined, and the 95th percentile curve shows that more than one-half will be longwall mined and the rest surface or continuous mined. After 2080, Appalachia and Illinois mines come online with the western region coal mines. The 5th and 50th percentile curves indicate that post-2080 coal will be longwall mined, while the 95th percentile curve projects continuous mined coal.

Over the course of 100 years, a total 208 billion tons of coal is needed to meet EIA reference case demands. There is a suitable amount of coal available (Table 23) to meet demand. As shown in Figure 15, the estimated mining cost range will increase. At the end of a 100-year period, cost will be \$15 - \$95/ton; median cost is \$52/ton.

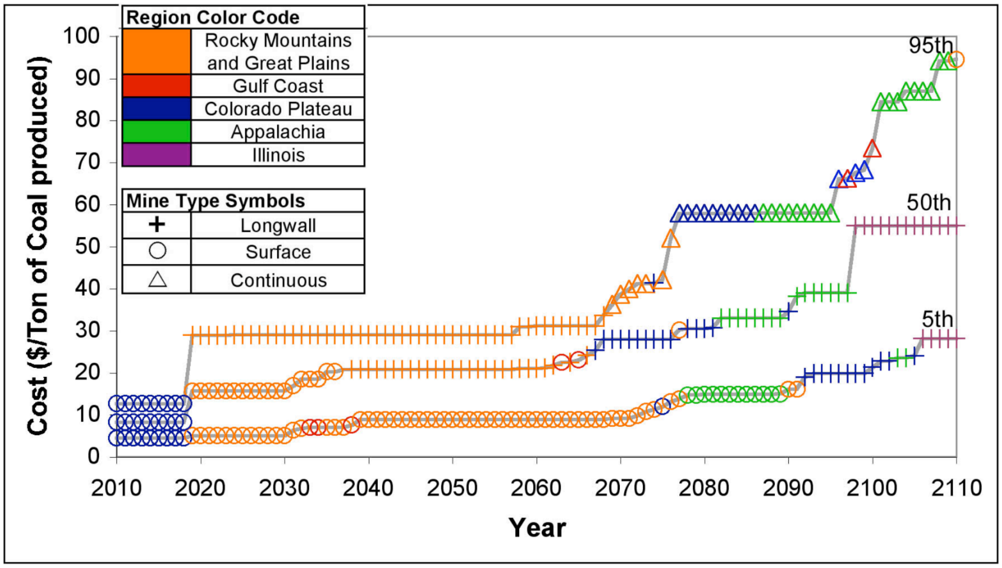


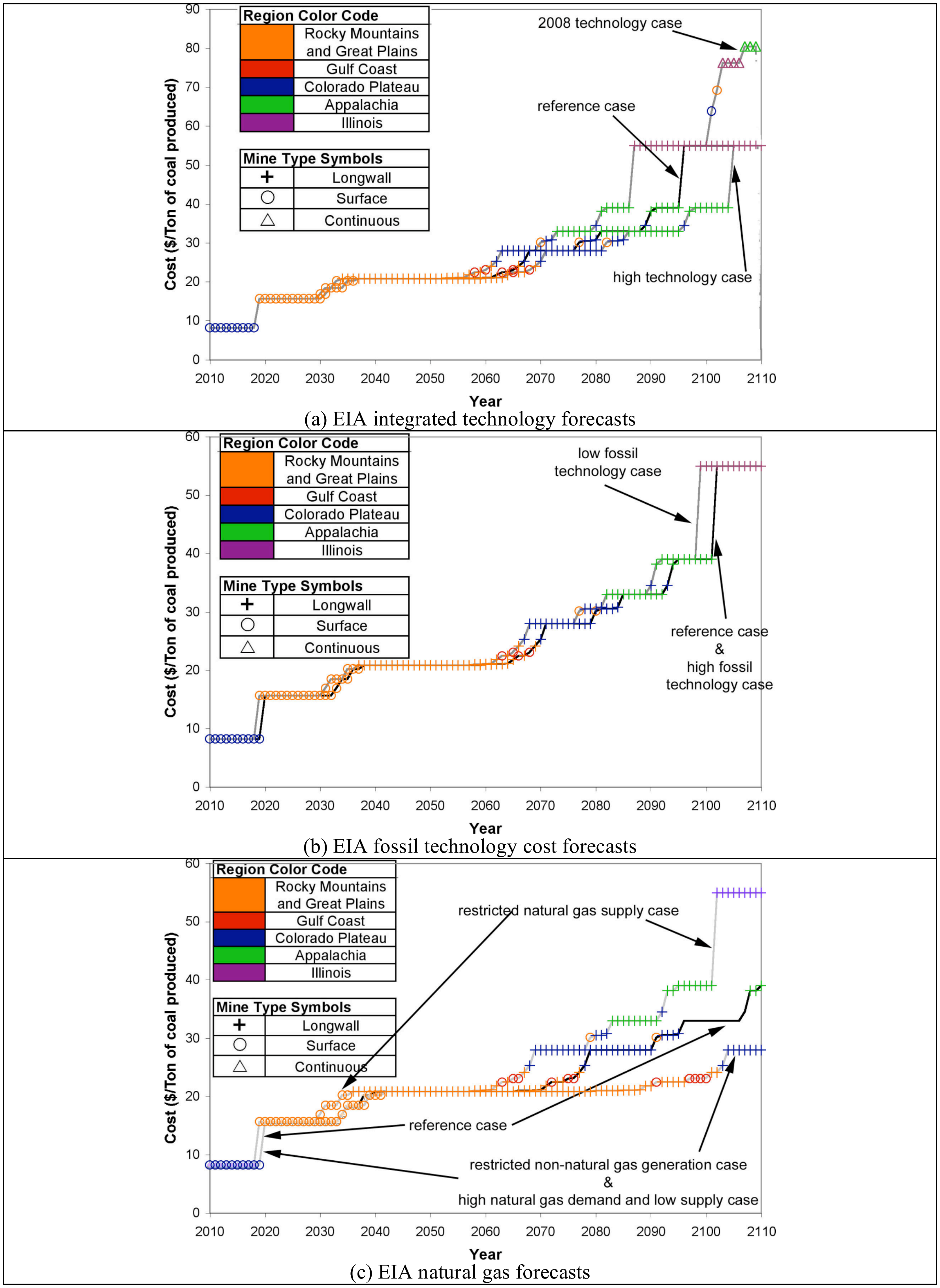
Figure 15 Mining cost curve under EIA reference case. To estimate total cost to supply coal to a power plant, transportation costs may be added. Rocky Mountains and Great Plains coal transportation costs are $12-$19/ton, Illinois coal transportation costs are $6/ton, Appalachia coal transportation costs are $7-$10/ton [17]. No transportation cost data is reported for the Gulf Coast and Colorado Plateau in the EIA coal transportation study.

6.1.2 Cost to meet alternate EIA energy demand forecast

Evaluating the EIA alternate energy forecast cases provides insight how coal supply and cost will change as a result of technology stagnation or innovation, and coal substitution for oil and/or natural gas. The median estimated costs are used to create least cost curves for each EIA alternate forecast case (Figure 16).

As previously discussed, coal demand will increase the most in the "restricted natural gas supply" case (Figure 16c), relative to the reference case. This forecast assumes that coal is used to replace natural gas and oil. Figure 16c shows that if natural gas and oil availability is restricted, coal supply and cost will increase relative to the reference case after 50 years. At the end of 100 years, median estimated supply cost will be 38 percent higher than the reference case cost. In this case, where coal demand increases for electricity generation and liquid fuel use, it is possible that we could run out of coal. A limited natural gas and oil case increases demand by 25 percent compared to the reference case. Similarly, allowing energy efficiency and technology to stagnate at 2008 levels will increase demand by 23 percent compared to the reference case (Table 1). In absolute terms, the "integrated technology reference case" demands more coal than the "natural gas supply and demand reference case." However, the "restricted natural gas supply" and "2008 technology" cases project similar demand increases relative to their respective reference cases. Therefore, it can be argued that the cumulative coal demand projected by the "2008 technology" case could be representative of the "restricted natural gas supply" case. Consequently, it can be concluded that coal costs could increase by 45 percent compared to the reference case (Figure 16a). Furthermore, if the "2008 technology" and "restricted natural gas supply" cases are similar, their cumulative coal demand could be as high as 256 billion tons (Table 19). If this is the case, we could run out of coal. The median estimated coal supply is 250 billion tons (Table 23). Overall, these increased demand forecasts show that if coal is substituted for natural gas or oil, or technology innovation stagnates at 2008 levels, costs will remain the same as the reference case cost for the 50 years. Over the course of the following 50 years, coal costs could increase by 35 – 45 percent and supply could be depleted.

Conversely, coal demand will decrease the most if carbon capture and sequestration technology is mandatory for new coal plants. Even if natural gas is scarce, obligatory carbon capture and sequestration for coal plants will dictate coal demand. The "restricted non-natural gas generation" and "high natural gas demand and low supply" cases shown in Figure 16c are the same. Figure 16c shows that although coal costs in these alternate cases remain the same as the reference case for 60 years, over the following 40 years coal cost will decrease by 28 percent compared to the reference case. Other alternate demand scenarios that improve energy technology do not have as significant and impact on coal supply and cost. If energy efficiency and technology innovation increase faster than in the reference case, as projected by the "high technology case" (Figure 16a), coal costs remain the same as the reference case for the first 50 years. For the following 40 years, cost is slightly lower than the reference case costs, but ultimately are the same over a 100-year period. Similarly, a specific case that assumes that natural gas or coal gasification combined cycle development and cost stagnates at 2008 levels ("high fossil technology") offers no change from the reference case (Figure 16b). Based on these results, to extend the longevity of our estimated resources and control coal costs, it is advisable to mandate carbon capture and sequestration technology for new coal plants.



(a) EIA integrated technology forecasts

(b) EIA fossil technology cost forecasts

(c) EIA natural gas forecasts

Figure 16 Coal cost curves for EIA alternate forecast cases. These costs represent only mining costs. To estimate total cost to supply coal to a power plant, transportation costs may be added. Rocky Mountains and Great Plains coal transportation costs are $12-$19/ton, Illinois coal transportation

costs are $6/ton, Appalachia coal transportation costs are $7-$10/ton [17]. No transportation cost data is reported for the Gulf Coast and Colorado Plateau in the EIA coal transportation study.

7 Discussion

This chapter evaluates long term coal supply and costs. The analysis shows that available resource is 250 – 320 billion tons. It also shows that over western surface and longwall mines will provide the cheapest coal for 60 years. After 60 years, certainty of cheapest technology option decreases. Coal could be supplied from longwall, surface, or continuous mines in any NCRA region. It is important to recognize the uncertainty associated with long term coal supply. The U.S. has invested and built a lot of coal-centric infrastructure. As mentioned at the beginning of this chapter, coal accounts for half of our electricity production and one-quarter of our overall energy portfolio. It is likely that we will continue to build coal-fired power plants and expand transportation networks to supply coal to demand centers. In order to make these investments worthwhile, we must take steps to reduce cost and supply uncertainty by improving technologies to extract it and our understanding of its availability.

To avoid running out of coal, it is essential to improve our understanding of our available resources, as well as innovate energy efficiency and technology. The analysis shows that demand will decrease if in a carbon constrained world, but would significantly increase if we substitute coal for natural gas and oil or allow energy technology and efficiency to stagnate. If we increase coal demand for electricity production and liquid fuel use, or by using 2008 technologies, we run the chance of running out of coal.

The sensitivity analysis of alternate EIA forecast cases shows that regardless of our energy policy, coal supply and cost will be the same as the reference case for 50 – 60 years. During this time, we should develop a research program that will provide a more accurate estimate of available coal resource. The benefit would be three-fold. First, by improving the certainty of existing geological data, we could more accurately estimate supply cost. The results show that the largest cost ranges are estimated in Appalachia and Illinois, where we have the lowest quality data. As previously discussed, these are the coal regions where the least detail is available about coal depth. Improving our understanding of coal seam depth in these regions will eliminate some of the mining cost uncertainty. Second, as we deplete thick and/or shallow seams, it is necessary to understand the technological restrictions posed by mining in deep and/or thin seams. As a result of more thoroughly categorizing our remaining resources, we will be able to identify technological needs for the mining industry. A specific example is the need to understand how seams interlay one another. Four coalfields reported interlaying seams, but it is likely that there are more coalfields that have interwoven seams. The analysis in this chapter assumes that interwoven multiple seams will be surface mined, such as those in the Danforth Hills, Deserado, Hanna Ferris, and Hanna-Hanna coalfields. However, if such seams are very deep, they must be mined by underground methods. The extraction cost for this resource can be better understood by developing (a) means of separating non-coal material from coal if mined by conventional underground methods that would extract non-coal material that is mixed with the interwoven seams, (b) a better understanding of how these seams are interwoven so that an optimal underground extraction method can be developed, (c) means to extract multiple deep seams by underground methods without compromising worker safety. Third, a more accurate estimate of available resource will support responsible energy planning. If we find that we have more coal than originally believed we could depend on this resource for additional energy needs, whether it be electricity generation or liquid fuels. If we find that we have less coal than we thought, we could develop alternative resources.

To reiterate the previous discussion of modeling caveats, the estimated resource and costs reported in this chapter are low. The estimated available resource is low because the data source, the NCRA, is not a complete assessment and lacks coal seam detail in some regions. By adjusting the data for analysis, additional coal resource is eliminated from the evaluation in this chapter. The estimated costs are low because the model optimizes resource development, assuming that greenfield mines will be developed without consideration of existing mining and transportation infrastructure and demand based on coal quality.

7.1 Research Needs

To improve our understanding of available coal resources and identify means to extract them, it is necessary to expand existing research, development, and deployment programs. I recommend investing in two programs. The first is the USGS NCRA, and the second is the Department of Energy's Mining Innovation of the Future (MIOF) program. As shown in Figure 6, the estimated cost range is large. We can reduce future resource supply and cost uncertainty by prioritizing the NCRA. With a revised and more reliable resource characterization, we can focus the MIOF to develop technologies that can extract our remaining resources. The NCRA and MIOF should be revitalized – the last activity reported by the NCRA was in 2005, and the MIOF ended in 2006. These programs are essential to better understanding coal resource availability and improving its recoverability. I will discuss the applicability of each program, and suggest additional funding.

7.1.1 NCRA

The NCRA would benefit from more uniform reporting that follows the USGS Circular 891 and reliability categories, expansion to cover all coal regions, and more detailed assessment. Using advanced geological detection technologies and improving collaboration can increase the reliability of the NCRA.

The most detailed report of coal geology in the NCRA is "measured" coal, which lies within 0.25 miles from the borehole (Section 2.2). It may be possible to increase the measurement resolution of coal geology by using advanced technologies such as remote sensing, which can provide geological information for whole sections of coalfield rather having to extrapolate between borehole sampling points. Remote sensing can detect rock qualities below ground in a way that boreholes can't. Boreholes provide information about the layers of rock and coal, but remote sensing provides a complete picture. It can improve understanding of how coal seams are oriented in a coalfield, seam fractures, variation in depth and thickness, and surrounding rock quality. With more detailed data, we will have a better understanding of potential mining challenges if the examined coal resource is developed.

As discussed in Section 2.2, the NCRA is a piecemeal effort that created regional resource assessments. The result is mixed data reliability and reporting methods. A more coordinated approach between regional teams is essential. Because the NCRA is a partnership between Federal and State geological surveys, the USGS should take the lead in managing the effort among all regional teams. Furthermore, it should seek to include industry, because exploratory coal resource assessments are detailed and reliable. Including these data will improve the NCRA.

To encourage and strengthen collaboration, I recommend a series of introductory NCRA workshops, wherein the USGS seeks input from the State geological surveys and mining industry to develop a roadmap and schedule for NCRA data collection and reporting. Within the first year of the proposed NCRA management change, the USGS should host at least one workshop of just Federal and State geologists, one workshop of Federal and industry geologists, and one workshop of all geologists. These workshops would serve as a platform to discuss the proprietary nature of privately collected coal resource data, uniform reporting requirements, and ways to make the data readily accessible to energy planners. Finally, the workshops would produce a schedule of goals and regions to examine in a timely fashion. Annual or semiannual meetings to report progress should continue. When the assessment is complete, and the roadmap goals are met the NCRA should reconvene to discuss the necessary frequency of updates and revisions of the dataset to reflect resource consumption.

7.1.2 MIOF

Unlike the NCRA, the MIOF was a collaboration between the Federal government and mining industry. The MIOF, a partnership between the DOE and National Mining Association, emphasized energy and water use efficiency, safety, and enhanced extraction and processing. Over the course of its 10-year lifetime (1996 – 2006), it commissioned studies of mine energy and water consumption, and sponsored industry research, development, and demonstration projects.

The MIOF should be revived, and expanded to include universities that have mining programs. As a result, industry would be encouraged to innovate, and universities would have incentive to continue and improve their mining engineering programs. Only 15 U.S. universities offer undergraduate mining engineering programs, compared to 25 in the early 1980s [22]. If we want to increase mining efficiency and performance, proper personnel training is imperative.

I recommend that the revitalized MIOF take the same approach as the NCRA. The DOE should take the lead in managing the program, reestablishing its partnership with the NMA, and initiating collaboration with universities. The DOE should host workshops wherein industry and academic researchers can discuss research needs, and identify the means to develop and demonstrate technology. The MIOF needs to set goals based on the NCRA, and take steps to meet them.

7.1.3 Cost

Potential costs to revive the NCRA and MIOF are estimated by examining past program expenses. No NCRA budget data could be found, but the MIOF was received $4 million from the DOE each year, which was supplanted by industry partners [23]. The NAS coal assessment report recommended increasing expenditures for current resource and reserve assessments by $20 million, and improving mine performance and resource recovery by $29 million per year. Industry partners involved in mine performance and resource recovery research would match costs. Current expenditures on both these endeavors is $10 million and $1 million, respectively [4]. Updating the MIOF budget of $4 million (2001 dollars), the proposed budget expansion is $4.7 million[4] - $29 million per year. The proposed NCRA budget expansion is $20 million per year.

[4] This estimate is based on an average 177.1 2001 consumer price index (CPI), and 207.3 2007 CPI [16. Ibid. [cited.

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Environmental implications of continued coal use and cost of rigorous regulation

1 Introduction

Chapter 3 showed how the mining cost model was used to estimate average mining costs for the National Coal Resource Assessment (NCRA). The NCRA summarizes the location, overburden depth, seam thickness, and coal quality of coalfields in the Colorado Plateau, Rocky Mountains and Great Plains, Northern and Central Appalachia, Illinois, and Gulf Coast basins. The NCRA coalfield depth and thickness are input into the model to estimate the cost of coal mining under the current version of coal mine regulation. A coal mine is like any other industrial facility. In addition to producing product, it has a land footprint, creates waste, and emits water and air pollutants. The Clean Water Act (CWA) and Clean Air Act (CAA) regulate its water and air impacts. The Surface Mining Control and Reclamation Act (SMCRA) is coal mining regulation that requires operators to remediate land and water damage.

The costs estimated in Chapter 3 do not adequately represent the environmental cost of mining. The CAA exempts coal mines from regulation. CWA regulation of coal mines is not consistently enforced. Moreover, the SMCRA is inadequate. First, SMCRA estimates a narrow set of mine damage costs. It focuses on property damage and water rights. Second, SMCRA is outmoded in two ways. Reclamation is its primary goal; the prevention of impacts is seldom mentioned in the regulation. Moreover, it was written to address land and water impacts. Although these issues remain important today, SMCRA should address contemporary environmental issues affected by mining. Furthermore, SMCRA should require prevention and reserve reclamation for cases where prevention fails. This chapter shows that environmental impacts from coal mining are significant, and that enforcing existing environmental regulations can reduce them.

This chapter begins with a description of mining's environmental impacts. This is followed by a description of currently applicable CWA coal mining regulations, CAA regulations that could be applied to mining, and the SMCRA. The regulation discussion is followed by a proposal of how SMCRA can be improved and more stringently enforced, as well as the possibility of how the CWA and CAA could further regulate mining. Next, the model is expanded and used to estimate the costs of environmental impacts covered by the revised SMCRA, CAA and CWA. Finally, the mining cost to comply with the proposed regulatory changes is compared to mining costs under laissez faire regulation.

2 Background

2.1 Mining's Environmental Impacts

Mining permanently transforms the environment. It disturbs land, emitting dust, triggering erosion, and mutating the landscape. Exposed coal emits methane and can acidify local water.

2.1.1 Overburden management problems

Underground mines can cause "subsidence" which occurs when overlying strata, called "overburden," collapse. Collapse occurs because coal is extracted from the earth leaving a hole behind. The hole is often referred to as a "mine void." When the overburden collapses, surface land is destabilized. Man-made structures and natural features may be affected. Buildings, roads, pipelines, and railroads are examples of man-made structures that can be damaged. Water bodies overlying the extracted seam are an example of a natural feature than can be "interrupted" if the supporting earth loses stability. The water will be dispersed through the fractures created by the collapsing overburden, so that its location is "interrupted." Structural damage and water resource interruption are traditional environmental concerns. SMCRA requires restitution to property and water right owners.

Overburden management is a surface mining challenge. Overburden must be removed from a coal seam in order to surface mine it. While the coal is mined the overburden must be stored or disposed of, and is considered "spoil". In flat coal regions, such as those found in the western U.S., the overburden can be stored in a pile adjacent to the surface mining pit. When the coal is completely extracted from the pit, the spoil is replaced in the pit. Under SMCRA, mine operators carefully manage the spoil. Each layer of earth is replaced with original soil condition in mind, saving the topsoil for the top layer. The topsoil is revegetated. SMCRA's goals for surface mine reclamation require the pit to be filled to "approximate original contour," meaning that the fill "closely resembles the general surface configuration of the land prior to mining and blends into and complements the drainage pattern of the surrounding terrain" [1]. Approximate original contour is almost impossible to achieve in mountainous terrain. Due to the steep slopes in mountainous coal regions, spoil is placed in valleys. "Variances," or exceptions to the regulation, are granted to many surface mines in mountainous areas that allow them to dispose of spoil in valleys and excuse them from restoring the mountaintop to its original contour. As a result, this practice is nicknamed "mountaintop removal." Mountaintop removal is contentious, not just because it permanently destroys mountain slopes, but because it buries adjacent valleys. As a result, valley streams and watersheds are interrupted. In this case, the surface water bodies are "interrupted" because spoil blocks their flow or displaces water from their pools. The Army Corps of Engineers permits surface water body fill under Section 404 of the CWA. Debate over whether spoil is a permissible fill material has led to legal action against mountaintop mining operations in West Virginia [2].

2.1.2 Water issues

In addition to interrupting water availability, mining can affect local water quality. Water and air react with the sulfur in the coal to create hydrosulfuric acid (H_2SO_4). For example, when water and air permeate coal waste piles or flow over cut coal faces in an underground mine, H_2SO_4 will be formed. The H_2SO_4 will dissolve metals from the coal and spoil into the water. If the water is discharged from the waste pile or mine, it is considered "acid mine drainage." Acid mine drainage can degrade ground and surface water quality, which affects plants and animals living in and around the water. SMCRA mandates water quality protection by:

> Avoiding acid or other toxic mine drainage by such measures as, but not limited to – (i) preventing or removing water from contact with toxic producing deposits; (ii) treating drainage to reduce toxic content which adversely affects downstream water upon being released to water courses; (iii) casing, sealing, or otherwise managing boreholes, shafts, and wells

> and [to] keep acid or other toxic drainage from entering ground and surface waters. [1]

The CWA regulates total permissible water pollutant levels from coal mining. Coal mines must have a National Pollutant Discharge Elimination System (NPDES) permit. Moreover, drainage can neither be alkaline nor acidic.

2.1.3 Air pollutant and greenhouse gas emissions

Air pollution can have adverse effects on human health and the environment. Airborne pollutants are categorized as criteria pollutants, greenhouse gas pollutants, and hazardous air pollutants (HAPs). These categories are based on either the prevalence of a pollutant or its effect. Some pollutants can fall into more than one category. Criteria pollutants are so-called because their permissible levels in ambient air are set according to human health or environmental criteria; these pollutants are ozone, particulate matter (PM), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and lead [3]. Coal mining emits significant amounts of PM, CO, NO_2, and SO_2. Greenhouse gases contribute to the "greenhouse effect," which refers to trapping extra heat in the Earth's atmosphere. The three greenhouse gases emitted directly and indirectly from coal mining are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). EPA defines HAPs as "toxic air pollutants or air toxics… that cause or may cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental and ecological effects" [4]. Coal mining is not cited as a source of any of the 188 HAPs.

When a mine is built, land must be cleared. The land is stripped of vegetation and leveled to accommodate surface buildings and mine roads. Vehicles rolling over the unpaved surface and earth moving activities, disrupt the soil, and emit dust (also referred to as PM) that impairs visibility. Criteria pollutants, PM, NO_2, SO_2 and CO are emitted from explosive detonation, fuel use, and coal cleaning. Removing overburden or the coal releases methane embedded in the seam. Vehicle fuel use and onsite power generation emits SO_2, NO_X, CO, PM, CO_2, and N_2O.

EPA exempts coal mining PM sources from the clean air act. It regulates, SO_2, NO_2, CO, and PM emissions from coal cleaning. Greenhouse gases are not yet regulated. But, mining is the 4th largest methane source in the U.S. Methane is a potent greenhouse gas. It has a 100-year global warming potential that is 21 times that of carbon dioxide [5]. Coalbed methane emissions accounted for 11 percent of 2006 U.S. methane emissions [6]. If EPA were to regulate greenhouse gas emissions, coalbed methane would be a targeted source to control.

2.2 Current Coal Mine Environmental Regulation Critique

There is a myriad of mine regulations, permitting agencies, and enforcing agencies. The SMCRA, CWA and CAA have decreased coal industry impacts on the environment. However, they could be relevant to current environmental concerns or work in a more complementary fashion. Often, the permitting agency and regulating agency may be at odds, or regulations may conflict. For example, the Army Corps of Engineers may permit a mine to dispose of its spoil in a stream, but that state's environmental agency is responsible for maintaining the water quality in that state. As another example, the SMCRA allows subsidence, which can disrupt surface wetlands, which is contrary to the CWA goal of wetland preservation. The following is intended to highlight regulations to be adjusted, and not an exhaustive discussion of existing regulations.

2.2.1 Surface Mining Control and Reclamation Act

The SMCRA was passed in 1977 and created the Office of Surface Mining (OSM) to enforce it. OSM maintains an abandoned coal mine reclamation fund similar to Superfund, which is used to reclaim abandoned industrial sites. The SMCRA regulates active surface and underground mines, as described:

- According to Section 508, operators must submit a reclamation plan to obtain a permit. This permit must contain information about the land to be surface mined: prior use, quality, agricultural productivity, and post mining use. It must also contain a description of "engineering techniques proposed to be used in mining and reclamation and a description of the major equipment; a plan for the control of surface water drainage and of water accumulation; a plan, where appropriate, for backfilling, soil stabilization, and compacting, grading, and appropriate revegetation; a plan for soil reconstruction, replacement, and stabilization."
- Section 509 requires coal mine operators to have a surety bond that the regulator can collect in the event that reclamation does not occur.
- Section 510 specifically addresses western coal mining (west of the one hundredth meridian west longitude), stating that these mines must not interrupt

farming activities or productivity, and can not disrupt surface and underground water supply.

- Section 515 prescribes surface mine environmental reclamation steps.
  - Land use reclamation is narrowly focused on maintaining its agricultural potential. It mandates how surface mine overburden must be stored and replaced, such that all subsoil and topsoil layers remain intact.
  - Reclamation standards are subjective. Surface pits must be filled, compacted and graded "in order to restore the approximate original contour of the land with all highwalls, spoil piles, and depressions eliminated." There is no description of how to measure the approximate original contour.
  - Environmental standards are not set, so much as reclamation methods are prescribed. For example, it provides explicit mine sealing and acid material management instructions, in order to avoid acid mine drainage. It describes how operators must store waste, detonate explosives, and manage mine fires.
  - The requirements have several loopholes. One example is that although Section 515 states that land must have native plant revegetation, it also says that foreign plants can be introduced if it "desirable and necessary to achieve the approved postmining land use plan." In other words, native plants are unnecessary.
- Section 516 regulates underground coal mining:
  - Subsidence must be prevented, "except in those instances where the mining technology used requires planned subsidence in a predictable and controlled manner" such as longwall mining, and must not be "construed to prohibit the standard method of room and pillar mining." In other words, subsidence is allowed.
  - Entryways from the opening must be sealed when no longer needed.
  - The same instruction for acid mine drainage, waste, and mine fire management is provided as in Section 515.

As detailed in the list above, except for western mines, SMCRA mandates specific actions instead of setting an environmental performance standard. By regulating in this manner, SMCRA is not flexible enough to accommodate future mining techniques. New technologies could be developed that continue to damage the environment but adhere to SMCRA's list of prescribed actions. It is possible to regulate by setting an environmental performance standard. For example, the CAA sets an allowable emission rate or ambient pollution level as its performance standards. Regulated parties are then at task to determine specific actions to meet these standard.

SMCRA has loopholes written into it, allowing invasive plants to be used for revegetation and not strictly forbidding subsidence. It also focuses narrowly on agricultural land use, rather than preserving land for the sake of preservation – for example, restoring forests so that they can be enjoyed. Moreover, it allows land to be restored to a different land use than its premining land use. In all, SMCRA makes mine land impacts permanent by allowing mine operators to establish a different post-mine land use and non-native plants.

2.2.2 Clean Water Act

The CWA regulates water pollutants from coal mines and onsite preparation plants.

Section 402 of the CWA requires mines to have a National Pollutant Discharge Elimination System (NPDES) permit to authorize their point source discharges. The permit addresses water pollution from coal preparation plants, the immediate area around them, and storm water runoff from coal refuse piles, and coal storage piles and facilities. If acid mine drainage occurs after closure and bond release, it is not regulated because the CWA is only applicable to mines before they are "reclaimed."

Acidified storm water runoff, mine and preparation plant discharges can pollute local water bodies. Section 303 of the CWA requires states to develop and adopt water quality standards based on water body use (recreation, water supply, industrial, agricultural, etc.) If the standards are exceeded in the pollutant-receiving watershed, the coal mine (and any other polluters) must reduce emissions.

While the permissible water pollution levels under the CWA are accepted, permissible fill is debated. Under Section 404 of the CWA, the Army Corps of Engineers permits the placement of fill or dredged material into the navigable waters of the U.S. Although the regulation is written specifically for "navigable" waters, it applies to any surface water body. Fines of $2,500 - $25,000 per day are levied the first time a fill permit is violated. The second time, the violator is fined $50,000 and/or imprisoned for two years.

2.2.3 Clean Air Act

Mine operators must have an air emissions permit and control criteria pollutants from their coal preparation plants. Other than preparation plant air emissions, air pollution from coalmines is unregulated. Surface coal mining emits a lot of PM, considered "fugitive dust," but is exempt from emission standards. Greenhouse gas emissions are not currently regulated.

2.3 Proposed Changes to Coal Mining Environmental Regulation

The SMCRA, CWA and CAA could be adjusted to complement one another and include current environmental concerns. The logistics of coordinating enforcement and permitting are not discussed here. Instead, the issues that should be addressed by these regulations are listed. These include elimination of coal mining exemptions, increased stringency, and greater emphasis on prevention:

1. Subsidence from underground mining should be prohibited, or allowed in minimal amounts. SMCRA regulates the entryways to underground mines. The land area that requires reclamation under SMCRA is limited to those entryways and any land occupied by support buildings. The regulation could add the land above the mine workings to the mandatory reclamation area, and require approximate original contour restoration for underground mines as it does surface mines.
2. Surface mines should be reclaimed to their original use. SMCRA allows exemptions to this rule, but it must be strictly enforced. As it is, SMCRA makes mining land transformations permanent by not stringently applying this requirement.
3. Reclamation requirements should be based on performance goals rather than specific prescribed actions.
4. Erosion during mining should be prevented. SMCRA assumes that erosion will be corrected under careful management and replacement of overburden soils. However, surface mining operations last for years, during which a substantial amount of soil can be lost.
5. PM emissions should be regulated. Coal mines should not be exempt from the CAA.
6. Prevention should be mandated. Avoiding subsidence and acid mine drainage would eliminate the need for post-mining reclamation. However, bond requirements should be maintained to address those cases in which environmental damage was not be avoided.
7. It should be illegal to fill surface water bodies with surface mine spoil. This practice is prevalent at mountaintop removal operations. Given the spoil storage challenges posted by mountaintop removal, such a move with outlaw mountaintop removal.

This chapter will calculate the prevention costs of the following, in order to lend insight into the additional costs posed by these recommendations:

- Backfilling cost to prevent subsidence from underground mines,
- Regrading and revegetation costs to ameliorate surface mine damage,
- Soil replacement costs to mitigate erosion,
- Methane well development and operation costs, to extract methane before and during mining,
- Coating exposed coal faces with sealant, grout, or liners to reduce potential acid generation,
- Avoiding mountaintop removal and valley fill by substituting robotic underground mines for surface mines.

2.4 Other Environmental Cost Analyses of Mining Regulation

Two surface mine environmental cost assessments were published shortly after the SMCRA passed in 1977. Their intent was to evaluate the cost that the SMCRA would impose on the coal industry; my analysis evaluates the cost to more stringently apply and enforce SMCRA. Misiolek et al. estimated SMCRA compliance costs in selected states. It calculated soil replacement cost, sales revenue and equipment depreciation in Ohio, Pennsylvania, Alabama, Illinois, Indiana, Missouri, Oklahoma, Montana, Wyoming, Colorado, Arizona, New Mexico, and Washington [7]. Randall et al. examined the impact of surface mining on a 1,600 square mile Kentucky watershed [8]. It monitored local water quality to ascertain acid mine drainage levels estimated the cost of adding alum and lime to treat the acidic water. The water monitoring data was also used to estimate the number of days that mine drainage exceeded safe levels, making the watershed unfit for recreation. A mid-range contingent value of a user day, from the Water Resources Council, was used to valuate the recreational loss. Fish restocking costs were based on a study of fish population change, and cost to purchase new fish. The expected cost of land damage is based on interviews with 1 percent of the households surrounding the watershed. The household interviews provided information about land and building damage and repair costs. The value of improved environmental aesthetic was determined by constructing willingness-to-pay curves. These curves relate electricity costs to the aesthetic of the coal mine environment. Misiolek et al. and

Randall et al estimated environmental costs of \$0.30 - \$2.70/ton (1980 dollars) and \$0.81 - \$1.72/ton (1976 dollars), respectively.

There is some overlap, but considerable contrast between the analysis in this chapter and the Misiolek et al. and Randall et al. analyses. Misiolek et al. and Randall et al. omit underground mining from their analyses, whereas this chapter examines underground and surface mining. Randall et al. focuses on a Kentucky watershed and Misiolek et al. focuses on a selection of coal producing states. Both of these analyses are specific to their study areas. The analysis in this chapter is broader, encapsulating all the NCRA regions. The mines modeled in this chapter are those that are generated by the model described in Chapter 2. The model designs and simulates these mines to optimize production based on coalfield characteristics. Modules are added to the model, to estimate ground subsidence from underground mining, land damage from surface mining, water consumption, water acidification, soil erosion, air quality pollutant and greenhouse gas emissions, and energy consumption. The environmental impacts are assessed for longwall, continuous, and surface mining.

Altogether, this chapter is a more thorough analysis of environmental impact and cost than the Misiolek et al., and Randall et al., studies. The only environmental cost quantified by Misiolek et al. is surface mine revegetation cost. Randall et al. estimated the expected value of treating acid mine drainage acid mine drainage levels and costs, which are addressed by this chapter. This chapter does not examine fish stocks, building damage costs or aesthetic. Randall et al. collected a lot of data specific to the watershed studied. It was not possible to collect this level of detailed data for a nationwide environmental impact analysis. Contingent valuation, as used by Misiolek et al., is an unsuitable environmental cost valuation method. An ORNL-RFF fuel cycle guidebook argues that estimating pollutant abatement costs is the best way to estimate environmental costs. "The value that individuals place in the impacts caused by emissions varies significantly" [9], which underestimates the true damage of an activity. The damage abatement costs in this chapter are calculated by an engineering economic approach; Misiolek et al. calculate their land damage costs similarly.

3 Method

Environmental impact and cost evaluation are added to the model that was described in Chapter 1. Two outcomes of these additions are (1) expected environmental impact incurred by mining NCRA coalfields to meet future coal demand if regulation continues in its current form and enforcement level, (2) environmental costs associated more stringent regulation. The environmental externalities quantified in this chapter are subsidence from underground mining, land damage from surface mining (including mountaintop removal and valley fill), potential water acidification, soil erosion, air quality pollutants, and greenhouse gas emissions.

The expected environmental impacts provide insight into the acreage of damaged land, tons of soil lost, tons of potential water acidification, tons of air and greenhouse gas pollutants emitted. Monetized costs, assumed to be prevention costs, cannot be assigned to all of the externalities. Costs were not assigned to air emissions, because analysis of control costs or technology substitution is complex and would entail a study on its own.

This analysis is limited due to the generalized nature of the model used. The environmental externalities are assessed for entire NCRA coalfields, to estimate general mining impacts. Case studies of specific sites in the coalfields were not possible. For example, groundwater location and flows around or through coalfields is not well documented. Therefore, acid formation can't be precisely estimated. Results are reported by NCRA region as well as coalfield. Furthermore, as discussed in Chapter 3, the model is not capable of simulating underground mining in four coalfields – the Danforth Hills and Deserado coalfields in the Colorado Plateau, and the Hanna-Ferris and Hanna-Hanna coalfields in the Rocky Mountains and Great Plains region – because the model cannot interpret the interweaving seams in these fields in order to simulate underground mines.

4 Underground mine subsidence

Subsidence occurs when overburden collapses after a section of coal is removed. The coal is no longer present to hold up the overlying strata, so the roof of the mined out area collapses, causing fractures throughout the overburden. This phenomenon happens immediately with longwall mining, because the panels and resulting voids are so large. Room-and-pillar mining results in a network of rooms and pillars. With a grid of roof support, subsidence takes longer to occur and can be less uniform and predictable [10].

There are several accepted subsidence estimation methods (a brief discussion of these methods, and the empirically based method used by the model is in Appendix C). The model estimates subsidence area and depth according to the size of the mine workings. In continuous mines, this consists of subsidence over rooms and pillar workings, and in longwall mines it is the longwall panels and the development sections. It is expected that subsidence area will be greater in longwall mines than continuous mines.

The subsidence depth is the maximum distance that the surface layer of overburden collapses when coal is removed below it (see Appendix C). Median calculated maximum subsidence depth is shown in Figure 17. Complete 5^{th} – 95^{th} percentile estimates are shown in Appendix C. In general, longwall mining subsidence was deeper than continuous mine subsidence. The greatest subsidence is expected to occur in the Rocky Mountains and Great Plains, where coal seams are thickest.

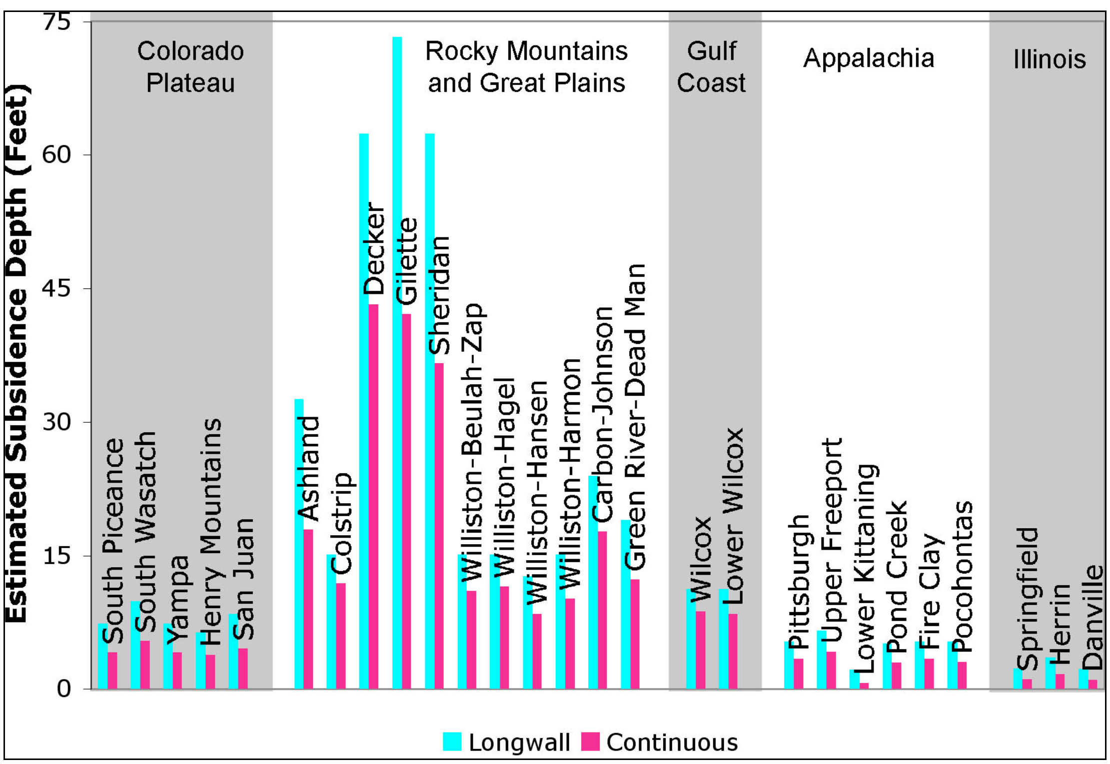


Figure 17 Maximum subsidence depth per mine type and NCRA region and coalfield.

Median underground mine subsidence area per total lifetime production is shown in Figure 18. The complete range of subsidence that could occur per coalfield and region is shown in Appendix C. Median continuous mine subsidence area is 0.01 ft^2/ton. It is uniform throughout all regions because continuous mine sizing is consistently proportioned to seam thickness and depth. The median surface area resulting from longwall subsidence is greater than that from continuous mine subsidence, and ranges from 0.25 – 3.80 ft^2/ton. The greatest subsidence per ton of longwall mined coal is expected in the eastern coal regions, Appalachia and Illinois. Estimated production rates in these regions are among the lowest (see Chapter 3).

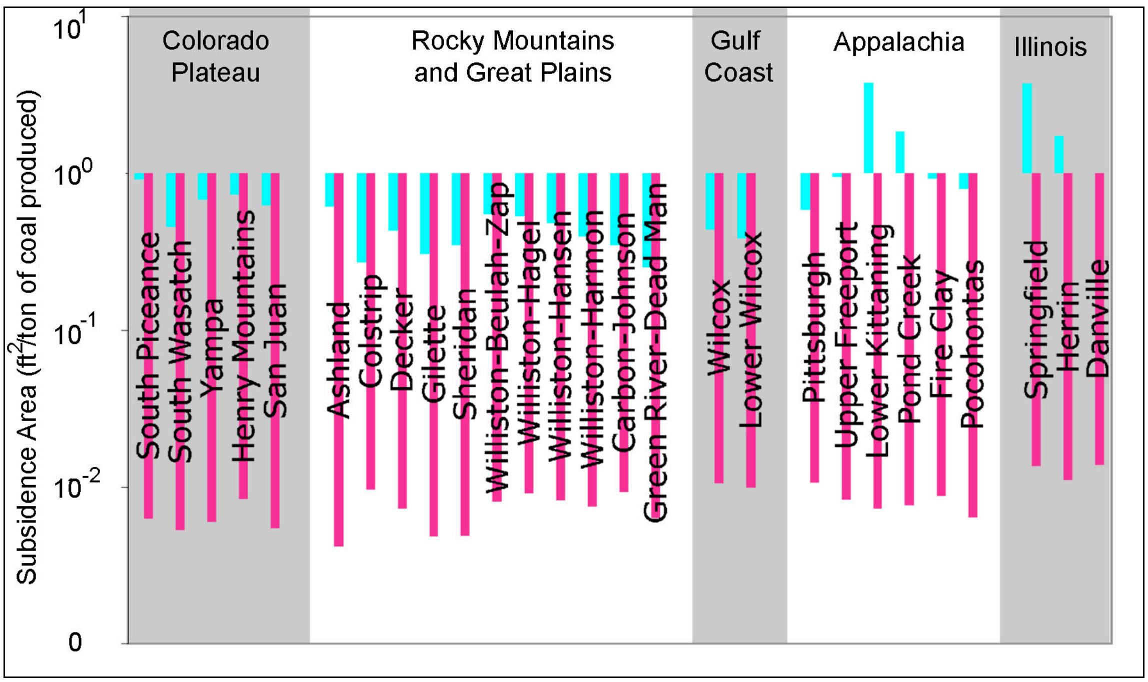


Figure 18. Comparison of expected longwall and continuous mine subsidence per NCRA region. Estimated subsidence accounts for total mine lifetime.

4.1.1 Subsidence Avoidance Cost

Mine voids can be filled to prevent or remediate subsidence. When coal is extracted it leaves a hole behind in the earth, which is frequently referred to as "a mine void." The act of filling the void with material intended to support the collapsed strata is called "backfilling," and the material is "backfill." Hydraulic cemented coal fines or coal combustion residues have been used in German [11, 12], Chinese [13] and Australian [14] coal mines. The fill reduces underground fire [12] [15], groundwater inflow and surface water impact [16]. It is uncertain whether fill reacts with groundwater [17].

Uncemented and cemented hydraulic, rock, and aggregate fills have also been used in mines [18].

Due to their stiffness and freestanding strength, cemented fills are sturdy compared to uncemented fill. Fill takes the place of the extracted coal. It reduces stress on the unmined pillars. Best fill options will be self-supporting and unyielding to collapse or further removal of remaining coal. Essentially, they will fulfill the physical function of the original coalseam in supporting overlying strata. A comparison of long term fill performance and potential groundwater effect are discussed in further detail in Appendix C.

4.1.1.1 Backfill technology description

Backfilling into the fracture and "gob" zone is evaluated. When overburden layers collapse, they do not fall uniformly. The overburden directly above the mined area is "gob," or extremely fractured material. Layers above that are less broken, and referred to as the "fracture zone." The example drawn in Figure 19 illustrates the formation and location of the fracture and gob zone relative to the mine void using longwall mining as an example. In the case of longwall mining, the gob zone forms directly above the roof supporting "shields" behind the longwall shearer, which is the region directly above the mined area.

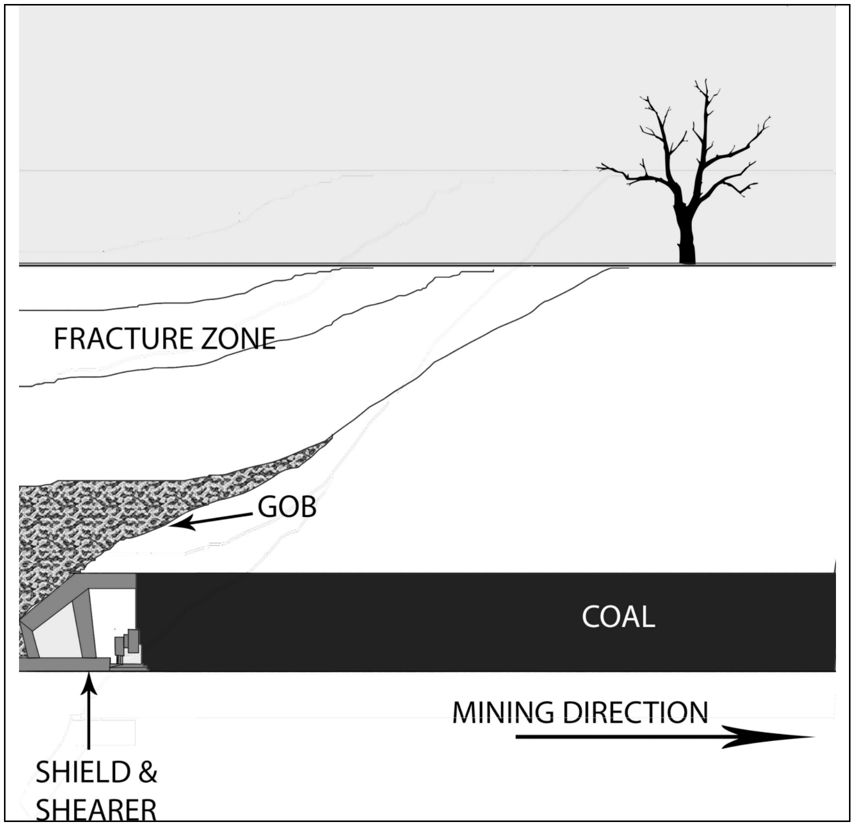


Figure 19. Underground mine subsidence without backfill.
Longwall mine is shown as an example. In a continuous mine, the gob zone is directly above an excavated room with a fracture zone above it.
Illustration not to scale.

The Australian Commonwealth Scientific and Research Organization (CSIRO) developed a fracture zone backfill technology that uses coal preparation plant fines (Figure 20). This technology consists of two injection wells that inject coal fines from the coal preparation plant into the fractures that form while the longwall is operating. As the longwall shearer cuts the coal and advances underground, the land overlying the mine immediately subsides. A set of shields, or movable roof supports is attached to the shearer so that the machine and attending miners are not crushed by the falling overburden. As shown in Figure 20, the injection wells are positioned above the longwall. They are placed before the longwall begins, so that backfill can be deposited into the fracture zone to stiffen it as subsidence is happening.

The CSIRO approach is promising but long term performance is unknown. CSIRO claims that 100 percent subsidence reduction is achievable by injecting a fill, volume equal to 80 percent of the mine void volume, into the fracture zone [19]. The gob zone is unstable. Over time the overlying fracture zone might collapse, even if it is filled. A gob fill option is shown on the right in Figure 20. It is assumed the CSIRO method can be used to inject fill into the gob for great stability.

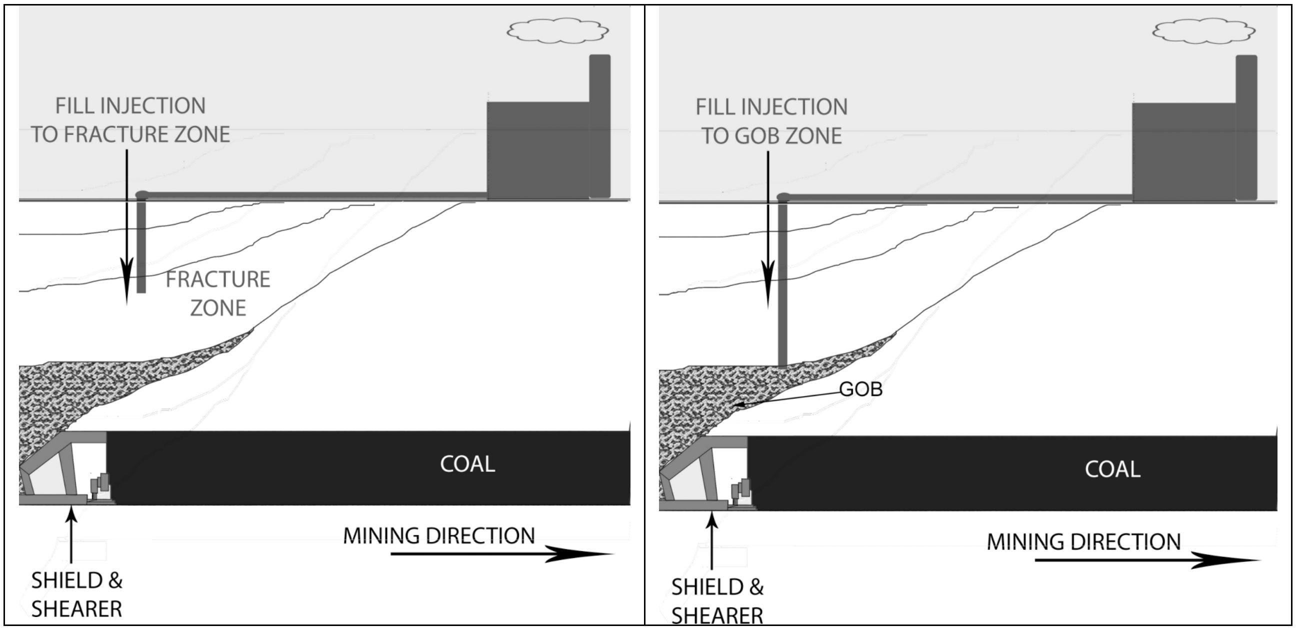


Figure 20. Backfill technology for underground mining. (Left): CSIRO fracture zone filling. Coal fines from the onsite preparation plant are injected into the ground. It is assumed that other fill materials can be injected by this method. Filling precedes the longwall face by 10 – 15 yards. Wells are set 600 yards apart, covering a 500 yd^2 control area. These wells are moved ahead of panel development and can be reused from panel to panel. (Right): Full filling, into gob area. Illustration not to scale.

4.1.1.2 Estimated cost per fill option

Backfill plant and distribution system capital cost is \$357K - \$4.6M, according to a survey of 23 Canadian mines [20]. Fill material options and costs are shown in Table 24. Equations 1 and 2 determine the amount of fill material needed for the gob and fracture zone injection option, respectively. Equation 1 assumes that the gob fill, V_{gob}, is equal to 80 percent of the mine void (MV), fitting with CSIRO assumptions. Equation 2 assumes that the fracture volume will be equal to the volume of surface subsidence. Surface subsidence volume is calculated by multiplying the maximum subsidence depth and subsidence area.

$$V_{gob} = \frac{0.8MV}{P} \qquad (1)$$

where V_{gob} = gob fill volume used per ton of coal
MV = mine void volume of mine type

P = mine production

$$V_{sub} = \frac{S_{\max} \times A_{sub}}{P} \qquad (2)$$

where V_{sub} = fracture fill volume used per ton of coal
S_{max} = maximum subsidence depth
A_{sub} = subsidence area

The material cost, fracture and gob zone injection costs are shown in Table 24. The 5th – 95th percentile injection cost estimates for all regions are shown in Appendix C; Table 24 displays the median estimate only. Rockfill was not considered an option for fracture zone filling because the particles would not be fine enough to fit in the fissures. The cost to fill the longwall mine gob and fracture zones, which include the cost of the fill material, system cost and operating costs, ranges from \$7 - \$52/ton of coal and \$8 - \$57/ton of coal, respectively. The continuous mine gob zone and fracture zone filling costs range from \$7 - \$52/ton of coal and \$0.6 - \$4/ton of coal, respectively.

Table 24. Fill Material Costs and Estimated Fracture and Gob Zone Injection Costs. These costs include the material cost, and capital and operating costs for the injection system over the mine's operating lifetime.

Material	Material Cost ($/yd^3)	Median Estimated Gob Zone Injection Cost ($/Ton of Coal Produced)		Median Estimated Fracture Zone Injection Cost ($/Ton of Coal Produced)[a]	
		Longwall	Continuous	Longwall	Continuous
Portland cement	80[b]	52	52	36	2
Rockfill	7[c]	14	13	NA	NA
Crushed limestone	35[d] – 46[e]	36	36	33	1
Coal combustion residue	3 – 8[f]	7	7	5	0

[a]Gob zone injection costs shown are modal median estimate. As shown in Appendix A, median estimates vary by coal seam.
[b] Cost is \$6.90 per 100 pounds. [21].
[c]Cost is Canadian \$5/tonne and density is 1.88 tonne/m^3[22]. Conversion to U.S. \$/yd^3 assumes an average exchange rate of Canadian \$1.4: US \$1 [23]
[d][24]
[e][25]
[f]Cost is \$2.5 - \$4.5/ton [26] and density is 90 – 135 lb/ft^3 [27]

4.1.1.3 Subsidence cost discussion and implications

Backfill's longterm performance and benefit is not known and must be investigated further. The structural integrity is dependent on the material chosen. While eliminating one problem, backfill can create other problems. If the backfill does not have the same physical qualities as the material it replaces, it may change groundwater flow [16, 17, 28].

Although Portland cement is durable, using it as a primary or supplemental fill component is costly and carbon intensive. Lifetime project emissions are not insignificant (see Appendix C for more detail). By using Portland cement, a backfilling project will result in indirect CO_2 emissions from the cement manufacturing process. Backfill for a longwall mine and continuous mine fracture zone backfilling indirectly emits 6 – 218 million tons and 0 – 3 million tons of CO_2; in the gob zone, backfill for single longwall mines and continuous mines indirectly emits 3 – 16 million tons and 3 – 10 million tons of CO_2, respectively. The higher estimate of longwall CO_2 emissions from filling the fracture zone is due to the large estimated fracture zone volume, in some thick seamed western coalfields. To reduce indirect CO_2 emissions, a non-cement or lower concentration cement fill can be used. Rockfill has a low amount of cement, and the crushed limestone and coal combustion residues options can be cement free. The best choice, however, is dependent on which material is strongest, permanent, and preserves natural groundwater quality and flow.

5 Surface mine pit reclamation

The footprint of a surface mine is comprised of the land cleared and used for pit area, mine roads, support facilities, and spoil, waste and coal storage. The model only accounts for surface pit area, so the footprint is underestimated. The total area of all mined pits is determined based on individual pit area, which is described in Chapter 2.

$$S_f = \frac{n_{pit} \times A_{pit}}{P} \tag{3}$$

where S_f = surface mine land area per ton of coal produced
n_{pit} = number of pits mined
A_{pit} = pit area
P = mine production

The median calculated land area per ton of coal produced is shown in Figure 21. The complete 5^{th} – 95^{th} percentile range per each coalfield is shown in Appendix C. As shown in Figure 21, Rocky Mountains and Great Plains surface mines disturb less land per ton of coal that they produce. The coal seams in this region are the thickest in the country, and have the highest production rates. Appalachia and Illinois coal seams have lower simulated production rates. As a result, surface mines in these regions disturb more land per ton of coal produced. (Refer to Chapter 3 for more detail about production estimated per region.)

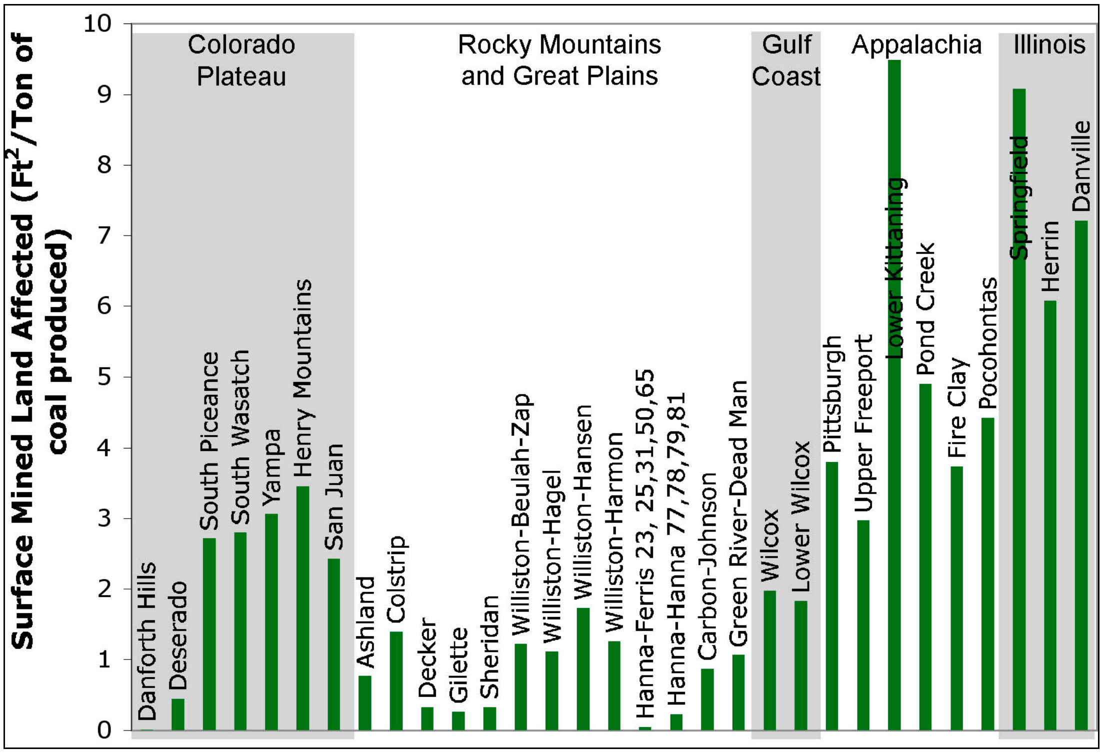


Figure 21 Median estimated surface mine land impact per NCRA region and coalfield, S_f.

5.1 Pit reclamation and avoidance costs

After mining, surface pits are filled in and graded to an "approximate original contour" to comply with SMCRA. This practice is suitable in western coal regions, which have shallow overburden. In Appalachia, where surface mining in mountains is nicknamed "mountain top removal," achieving the "approximate original contour" is impossible. (See Appendix C for a brief discussion of the environmental challenges and policies related to Appalachian mountain top removal).

Two options to mitigate surface mine land damage are assessed. The first is land reclamation, which addresses damage after it occurs. It does not restore mined lands to their original condition. The second is automated underground mining, which prevents damage by avoiding surface pit mining. Autonomous, or robotic, mining can be used in risky conditions. Mountainous Appalachian coal seams are the perfect candidate for robotic mining. The mining industry argues that it is too dangerous to use conventional underground mining techniques because the region's soil is unstable, and surface mining is a cost effective solution [29]. Automated underground equipment reduces the number of miners needed underground, and so offers a safe underground mining substitute for mountain top removal mining in Appalachia. If surface mining is still pursued, regrading and revegetating land is a low cost and low performance option because it does not restore mined lands to their original condition. Several analyses of land use before and after mining show that mined land is typically turned into grassland rather than restored to its original condition – typically forestland. Essentially, mines transform forests to grass and pasture, because it is cheaper to plant and maintain grass than it is to plant and nurture trees to maturity (a detailed discussion of land transformation, particularly in Appalachia, is in Appendix C).

5.2 Revegetation and reforestation costs

Costs to regrade, revegetate, and reforest land are \$1,300/acre, \$1,350/acre [30], and \$120 - \$1400/acre [31], respectively. The total estimated reclamation rate is therefore \$2,770 - \$4,050/acre. Estimated 5^{th} – 95^{th} percentile cost to revegetate each region is shown in Appendix C. Costs are low; the 95^{th} percentile cost never exceeds \$2/ton of coal produced, and the average median cost is \$0.2/ton of coal.

5.3 Mountaintop removal and valley fill avoidance cost

Autonomous mining cost and production rate are estimated. Sensors and autonomous or remote controls on underground devices enable unmanned mining. These devices can also improve productivity by eliminating downtime and cutting error. According to the CSIRO, smart longwall sensing technologies steer the longwall perfectly straight, increasing productivity by 30 percent. The CSIRO is pioneering longwall automation by using U.S. Army autonomous tank driving technology. The Beltana mine in New South Wales is currently demonstrating the technology. CSIRO believes that within 10-15 years the robotic capabilities will be fully autonomous. Longwall automation is further discussed in Appendix C, which also includes estimated costs for robotic longwall systems and unmanned continuous miners.

5.4 Discussion of Surface Mine Land Cost

To mitigate surface mine land impacts, land can be reclaimed after mining or surface mining can be avoided altogether. Another option, not evaluated, is disposing of excess spoil in landfills. This option was not assessed because distances from the minesite to potential landfills are too uncertain without in depth geographical analysis of regional land use. The estimated cost to reclaim the land to regulatory requirements or use robotic mining equipment may be low. The revegetation cost estimate only addresses permitted area, and land use data show that current reclamation practices do not restore land to its original condition. The potential success of autonomous mining machines is uncertain at best. These are still experimental technologies, and may be more expensive and less effective than assumed. Like conventional underground miners, they may face challenges when applied in the unstable soils of Appalachian coal seams. At the moment it appears that there is no research or development activity involving this technology in the U.S. – a situation that needs to be rectified. The potential of this technology will be better known as it is further developed and commercialized.

6 Soil erosion

Unless a mine undergoes concurrent reclamation to fortify soil through revegetation, replacement, or constructed reinforcement, soil will be lost throughout the mining process. Additional problems resulting from erosion include wind channeling, water channeling and flooding, nutrient loss and miner safety hazards from unstable ground and rockfall. Restoring soil to its original state is difficult. Although mine operators will replace soils, and often do so with attention to the placement of soils to best mimic the original geology and topography, the soil is not as compacted as it was in its original state. It is impossible to recreate natural compaction. Because they are exposed to the elements from storage practices during mine operation, these soils may have degraded. Despite best intentions, soil nutrient levels and physical properties are changed after mining.

6.1 Erosion Estimation

U.S. government agencies use the Revised Universal Soil Loss Equation (RUSLE) [32-34] to calculate soil erosion rates, and the Wind Erosion Equation (WEQ) to calculate wind erosion rates [32]. These equations are dependent on site specific qualities. They are shown in Appendix C. The RUSLE is used to calculate water induced soil loss. The regional erosion factors input to the RUSLE, developed by EPA, are also shown in Appendix C. Instead of using the WEQ, wind erosion rates measured by the EPA were used to estimate wind induced soil loss. The EPA AP-42 wind erosion rate is 0.38 ton/acre/year [35]. Although it was developed to estimate erosion in western surface mines, it is assumed that it can be applied throughout the country. Wind erosion rate is lower than the water erosion rates in Kansas City, St. Paul, and Pittsburgh, but falls within the range of water induced erosion in dryer regions such as Denver. This implies that wind erosion is a minor contributor to total erosion in the Illinois and North and Central Appalachian Basins, whereas it is significant in the western coal regions.

The RUSLE and AP-42 erosion rates were input to the model to calculate erosion and associated soil replacement. Water causes almost all of total erosion (see complete results in Appendix C). Calculated soil erosion is greater in the Appalachian and Illinois Basins Figure 22c and d) than in the western coal regions (Figure 22a, and b). Total erosion is directly related to the surface area affected by mining. Surface mines have the greatest land area, followed by longwall mining. Longwall mines require more surface support area than continuous mines because they produce more coal. Consequently, they have more exposed area that can erode.

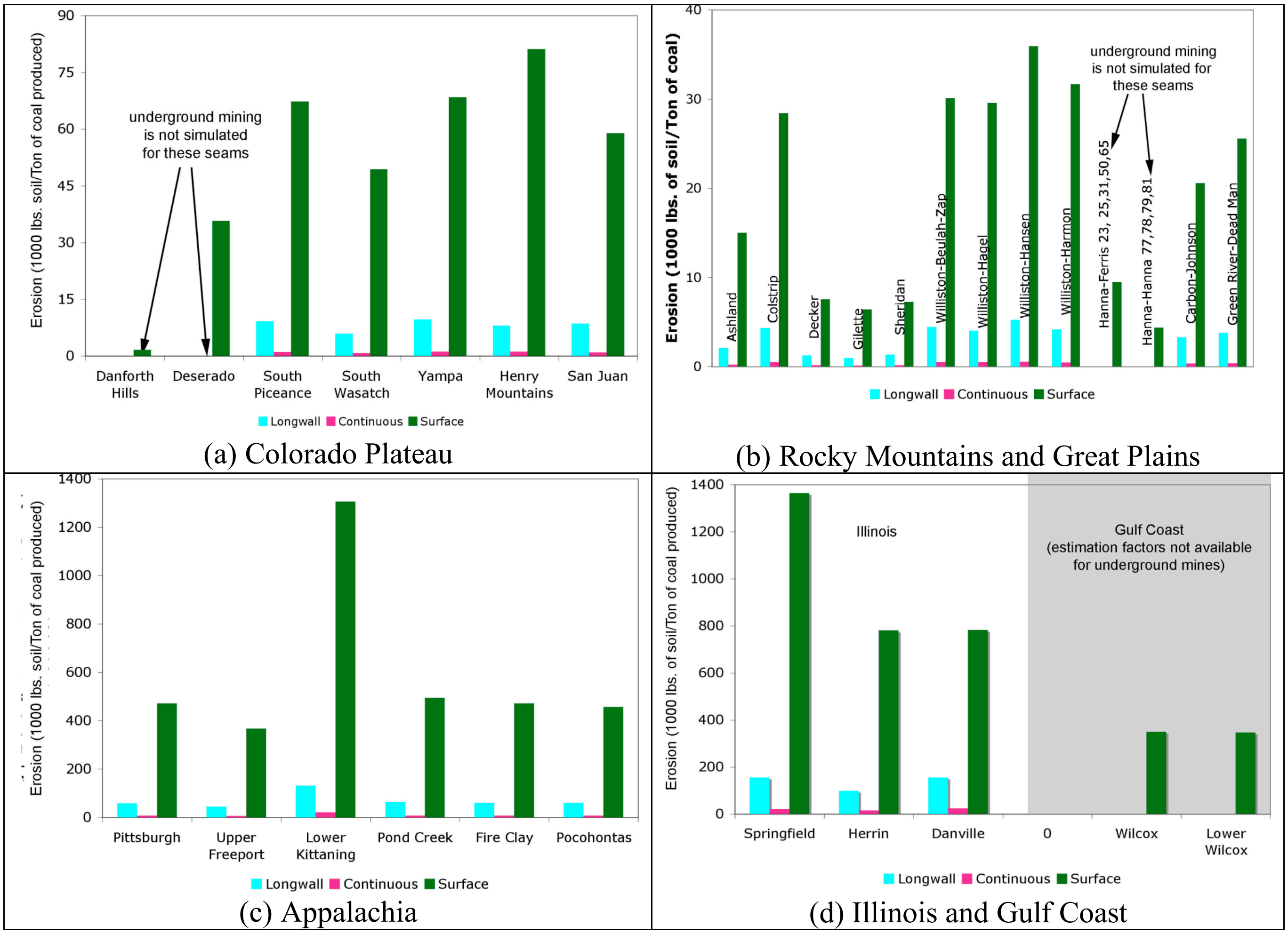


Figure 22 Estimated soil erosion per mine type and NCRA region and coalfield. Surface mining erodes more soil than underground mining in all regions because it denudes a larger area. More soil is eroded per ton of coal produced in Appalachia and Illinois because mine production rates are lowest, and water induced erosion rates are highest in these regions.

6.2 Erosion avoidance cost

To estimate the value of soil loss, USDA soil valuation is used. The USDA states that the "cost to return soil to its original non-eroded condition is priceless," but settles on a soil replacement value of \$19/ton [36]. The soil replacement value accounts for the "cost to replace soil functions and remedy offsite damage," which accounts for air and water quality, as well as soil nutrients. The cost to avoid erosion is negligible, less than \$0.01/ton (Appendix C.)

6.3 Erosion discussion and implications

The prevailing water erosion estimation technique endorsed by the USDA, OSM, and EPA used to develop the water erosion factors used in this assessment were recently critiqued as being inappropriate for erosion prediction because it does not estimate the redistribution of soil [37]. That is, this technique determines only the material that is moved within a defined area, but not the amount that is removed nor added. It is argued that erosion monitoring is needed in order to get a better idea of the erosion that is taking place. Absent a complex monitoring system, however, these equations are the best means available to estimate erosion.

7 Acid Mine Drainage

Coal quality and mining operations vary by site, and warrant site specific acid mine drainage prediction. However, detailed geological information needed to estimate potential acid mine drainage is not available. A more detailed analysis would improve accuracy, but is not possible given the amount of information known about U.S. coalfields and surrounding water. Experts acknowledge that predicting acid mine drainage is difficult; groundwater flow prediction is complex [17] as is drainage prediction [38]. A few of the things that must be available in order to predict AMD are outcrop exposure measurements, drillhole logs, geological sections and core assays [39]. Although outcrop data are available for part of the National Coal Resource Assessment, an analysis of estimated potential distance from possible mines to outcrop is beyond the scope of this analysis. To predict acid mine drainage, EPA recommends collecting samples and determining acid generation potential from them [39]. The samples are drill samples collecting during mine planning.

In this thesis, the maximum acid production potential is calculated as a function of regional coal sulfur content (refer to Appendix C for detail) and used as a metric of mining impact on water quality. Table 25 shows the NCRA reported regional coal sulfur content used to estimate the maximum acid production potential and calculated maximum acid production potential.

Table 25. Assumed sulfur content and acid production potential per NCRA coal region (tons acid/ton coal)

Region	Percent Sulfur [40]	Estimated Acid Production Potential
Colorado Plateau	0.83	26
Rocky Mountains and Great Plains	0.48	15
Gulf Coast	1.09	34
Appalachia	2.14	67
Illinois	3.55	111

7.1 Acid Mine Drainage Prevention

We consider three ways to prevent acid mine drainage:

- Option 1: Seal an underground mine's opening so that it floods after mining is completed. The water in the mine prevents air from touching the coal. The reactants are not all present for acid formation. At least in principle, acid does not form. Furthermore, because water is sealed in the mine, there is no drainage. However, if there is the seal fails, the large water discharge can be disastrous. A flood of acidic water can contaminate local water and soil. If the discharge is large enough, it can also inundate local dwellings.
- Options 2: Add alkaline material to reduce the acidity of the water draining from the mine, which requires perpetual treatment. The treatment could start any time during the mine's life. However, this is an option that must be continued forever, or until all acid forming materials in the mine have formed acids and drained out of the mine.
- Option 3: Install a physical barrier that prevents contact between the acid forming material (coal), water, and air. This is a one-time treatment that prevents environmental damage.

Option 3 is evaluated because it does not pose the hazard like Option 1, and does not require constant maintenance like Option 2. Two possible barriers are examined in this analysis of Option 3. A sealant, which can be painted onto exposed coal face, can be used in underground and surface mines. A grout is also applied to the coal face, and could be used in surface and underground mines as well. A landfill liner can be used in a surface mine pit before it is filled and regraded for reclamation.

7.2 Mine sealant cost

Sealants and liners can be used to prevent acid formation. Sealants are a penetrating coating that prevents water and air from reacting with exposed rock in oil and gas drillholes, and metal mines. Grout works in a similar fashion, but simply coats the rock.

Landfill liners can be put into surface mining pits before spoil is replaced; the barrier will prevent acids from leaching into the underlying strata.

The cost to apply these materials to mines is calculated according to the surface area, based on the mine dimensions assumed by the model described in Chapter 2, to be covered. Underground mine surface area is equal to the gate pillar surface area in longwall mine development sections and all pillar surface area in continuous mines. It is assumed that sealants can't be applied to longwall panel walls due to roof collapse.

Landfill liners and sealants offer protection against acid generation, at different costs. The landfill liner considered is a geotextile layer with sodium bentonite clay, which is a material that is used in landfills throughout the U.S. The installed (1994) cost is \$0.42 - \$0.60/ft^2, but depends on shipping distance, area to be covered, market demand and season [41]. Sealant application and material costs are \$2-8/ft^2 [42], as applied to metal highwall mines. Shotcrete or gunite grout application cost, including overhead and profit is \$1.94 - \$7.40/ft^2 [43].

The 5th – 95th percentile ranges of calculated acid mine drainage avoidance costs are shown in Appendix C. Because sealant and grout material cost are so similar, the cost to use them is the same. "Coating costs" refers to sealant and grout cost interchangeably. Longwall coating costs range \$2 - \$12/ton in the Colorado Plateau, Appalachia, and Illinois, with a median cost of \$4/ton. Costs are slightly higher in the Gulf Coast region, \$2 - \$17/ton with median cost of \$5/ton. Broader ranges of cost are found in the Rocky Mountains and Great Plains region because there are thicker seams of coal in this region. Costs in this region range from a minimum 5th percentile cost of \$2/ton to a maximum 95th percentile cost of \$92/ton. Median costs range from \$5/ton to \$21/ton. Finished mines in the Rocky Mountains and Great Plains thus have more surface area to be coated than mines in other regions. Similarly, continuous mine grouting costs are most costly in the Rocky Mountains and Great Plains region, with a maximum possible cost of \$23/ton, but are otherwise less than \$8/ton throughout the remaining coal regions. Continuous mine coating median coating costs were \$0 - \$7/ton throughout the NCRA regions.

Coating surface mine pits incurs a larger range of cost; using a landfill liner is the cheaper option. The landfill liner option is on average 10 percent of the cost of the coating option.

7.3 Coating cost discussion

Though Option 3 was chosen over Option 2 because it is lower maintenance, the lifetime of the materials is not certain. Although EPA has tested sealant effectiveness in metal mines, they have not been used in coal mines. Moreover, there are no reports about the expected lifetime of these sealants, gunite and shotcrete, or landfill liners. Landfill liners have a debatable service lifetime. One study cites leading environmentalist's opinion that that many liners fail within the first five to ten years, and very few last more than 50 years [44]. Another study states that liners have a 80 year service lifetime [45], while another believes liners last 200 – 750 years but acknowledges only 10 – 25 years of monitoring experience [46]. The most optimistic estimate is a 1,000 year lifetime [47]. As in the case of backfill technology, there is a clear need for an expanded U.S. research program. Though landfill liner lifetime is uncertain, it is likely that it will last longer than a layer of sealant, shotcrete, or gunite; it is also cheaper, and so a better option to mitigate acid leaching from a surface mine pit. Until additional longevity data can be collected, landfill liners are the best option the line a surface mine pit to avoid subsidence, and sealants, gunite and shotcrete can be used interchangeably to create a barrier in an underground mine.

8 Air Quality and Greenhouse Gas Emissions

Conventional criteria pollutants and greenhouse gases are released by coal mining activities. Dust emissions from disrupting the soil and criteria pollutant emissions from fuel consumption and coal cleaning contribute to air pollution. Removing overburden or the coal releases methane embedded in the seam. Vehicle fuel use and onsite power generation emits SO_2, NO_X, CO, PM, CO_2, and N_2O. The analysis of air pollutant emissions discussed here is limited to fuel combustion, explosives detonation, coal cleaning, and vehicular dust generation. These emissions are estimated by using EPA and EIA emissions factors applied to mine processes simulated by the model.

Coal mining is not a regulated air pollution source. If the CAA is expanded to include coal mining, understanding mining's air pollutant emissions will be important. This section discusses current coal mining air emissions.

Criteria pollutant and greenhouse gas emission factors are taken from several EPA resources: the AP-42 guidelines, Emissions and Generation Resource Integrated Database (EGRID), MOBILE6, and greenhouse gas emissions inventory. The EIA greenhouse gas reporting guidelines provided additional greenhouse gas emissions factors. The emission factor used for each process examined, and its source are summarized in Table 26.

Table 26. Air pollutant emissions factors used in this analysis

Process	Emission factors available	Source
Coal cleaning	PM, SO_2, NO_X, CH_4, CO_2	EPA AP-42 [48]
Surface mine ANFO detonation	CO, SO_2, NO_X	EPA AP-42 [49]
Truck, shovel, and vehicle use to move and break overburden and coal	TSP (in this analysis, assumed to be "dust")	EPA AP-42 [50]
Surface mine vehicle diesel consumption	CO, NO_X, PM_{10} CO_2, CH_4, N_2O	MOBILE6[51] EIA Voluntary Greenhouse Gas Reporting Guidelines[52]
Underground mine equipment electricity consumption	CO_2, CH_4, N_2O NO_X, SO_2	EIA State-Level Greenhouse Gas Emission Coefficients for Electricity Generation [53] EGRID [54]

Criteria pollutant emissions are not discussed at length in the body of this chapter because their control will not been evaluated here. Appendix C provides an in depth discussion of criteria pollutant emissions and estimated emissions rates.

Reducing fuel use, increased pollutant scrubbing at preparation plants, suppressing dust, and capturing methane before and during mining are options to air pollutant and greenhouse gas emissions. For starters, a mine could reduce diesel use by increasing machinery efficiency or fuel substitution, or using other fuels, such as natural gas, biodiesel, or battery. In addition, it could spray water over its operations to suppress dust. If water suppression is too costly and interferes with surface mining operations, underground mining could be substituted to avoid dust emissions. Additionally, a mine could capture methane before and during mine operations. It may be possible to use this gas for power generation onsite or to supplement natural gas supplies.

Of these mitigating options, two are assessed. Methane capture cost is evaluated to estimate the cost to reduce methane emissions. Underground mine substitution for a surface mine is examined. A scenario analysis later in this chapter will draw upon the robotic mining analysis in Section 5.3, substituting underground mining operations for surface mining. The costs to change fuel consumption throughout the process are challenging to estimate because alternative fuel vehicles are not widely available.

8.1 Coalbed Methane emissions

Coal was formed when plant matter decayed and compacted under layers of geologic material. Methane is another product of plant matter decay, and is simultaneously formed with coal. Methane in shallow coalbeds may escape to the atmosphere, but methane in deep coalbed is trapped until the seam is broken. The seam may be fractured by an earthquake, drilling, or mining.

According to the EPA Methane to Markets program there are 39 coalbed methane projects in the U.S. at active underground or abandoned mines that sell 41 billion cubic feet of coalbed methane each year [55]. Of this, 38 billion cubic feet are developed in coalfields where there are active underground mines. The largest producing coalfield is the Buchanan seam in Virginia, which sells 15 billion cubic feet of methane per year. The next largest producing coalfield is the Blue Creek seam in Alabama, which sells 13 billion cubic feet of methane each year. These coalbed methane projects are coalfields that are home to active underground mines. Excluding the Buchanan and Blue Creek projects, the average coalbed methane development project at an active underground mine sells 1 billion cubic feet of methane per year. The average coalbed methane project at an abandoned minesite produces 176 million cubic feet of methane annually. The following discussion, of methane emissions from coal mining and options to mitigate them, does not account for these existing projects. The coalbed methane analysis assumes that methane has not been extracted. As a result, estimated methane emissions may be higher than they may be if the methane was already extracted. The NCRA coalfields that have methane projects in coalfields that are actively mined, as reported by the EPA Methane to Markets program, are the San Juan coalfield (20 million cubic feet per year), Pittsburgh (4 billion cubic feet per year), and Pocohontas (15 billion cubic feet per year – this is the aforementioned Buchanan coalbed methane project). These projects are associated with active underground mines, but methane development may deplete coalbed methane beyond the surface boundaries of the minesite. Coalbed methane is stored in the coal seam, and travels through the seam fracture and fissures. Developing methane in one section may activate methane flow from beyond the project footprint.

Methane emissions from coal mining vary according to mining method, seam depth and richness. The EPA developed a U.S. specific coalfield methane emissions estimation method, which is used in this analysis. The EPA estimated methane emissions from coal mining in several reports [56, 57]. To estimate methane emissions, EPA uses MSHA measured emissions data from underground mines and in situ coal quality data for surface mines. The MSHA dataset covers 1990-2003 ventilation measurements, excepting for 1997. Basin emissions factors for surface mining operations are based on in-situ methane content in coals. The emission factor is a multiple of the in-situ content, to "account for methane contained in overlying or underlying coal seams or other strata" [6]. EPA assumes surface mine methane emissions factors are twice the in-situ content, but in the 1993 assessment, the assumed emissions factors were three times the in situ content. The report does not explain why there is a difference between 1993 and 2003 emissions factors. EPA post mining emission factors are 25-40% of in-situ methane content. EPA surface and underground mining missions factors, used in this analysis, are summarized in Table 27. The EPA methane regions are not the same as the NCRA coal regions. Emissions factors as assigned, as appropriate (see Appendix C for discussion of how EPA methane regions intersect NCRA coal regions).

Table 27. Methane emissions factors and estimated emissions rate (ft^3 methane/ton coal produced) per mine type and NCRA region [56, 58].

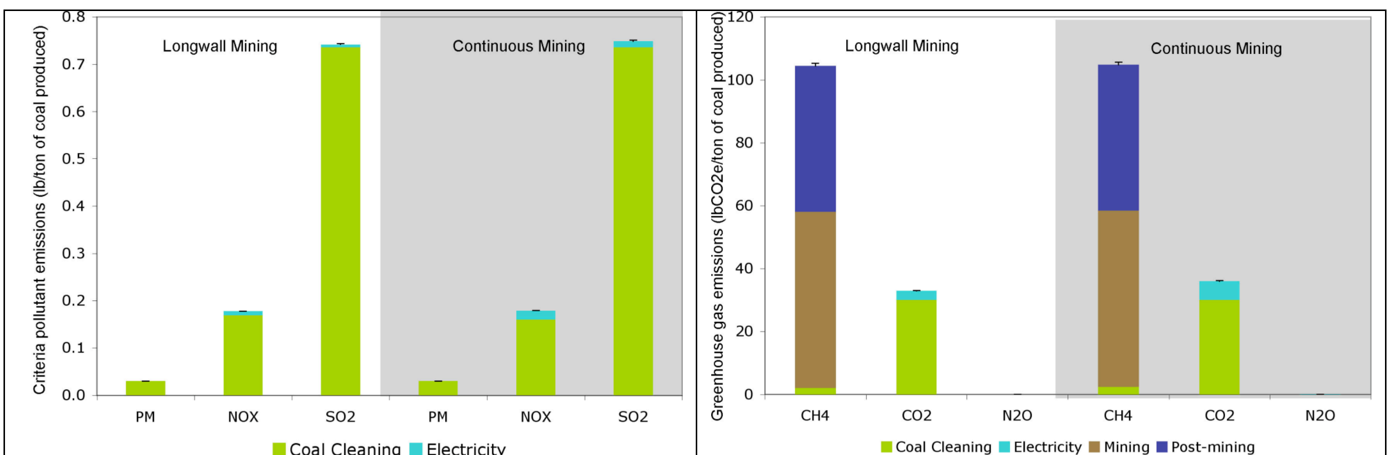
Region	Coalfield	Surface mine	Post mine surface	Underground[a]	Post mine under ground
Colorado Plateau	Danforth Hills, South Piceance	66	11	76	64
	Deserado, South Wasatch, Yampa, Henry Mountains	32	5	76	32
	San Juan	15	2	76	34
Rocky Mountains and Great Plains	All coalfields	11	2	76	5
Gulf Coast	All coalfields	66	11	76	42
Appalachia	Pittsburgh, Upper Freeport, Lower Kittanning	119	19	88	14
	Pond Creek, Fire Clay, Pocohontas	50	8	89	20-130
Illinois	All coalfields	69	11	45	21

[a]Calculated from 1995 methane emissions and production data [58] and assuming methane density of 47,000 ft^3/ton [59]. The Rockies and Northern Great Plains coal basins are assumed to be in the "Western Coal Fields" region. The estimated overall methane emissions factor for all underground mines is 83.15 ft^3/ton.

8.2 Estimated air emissions rates

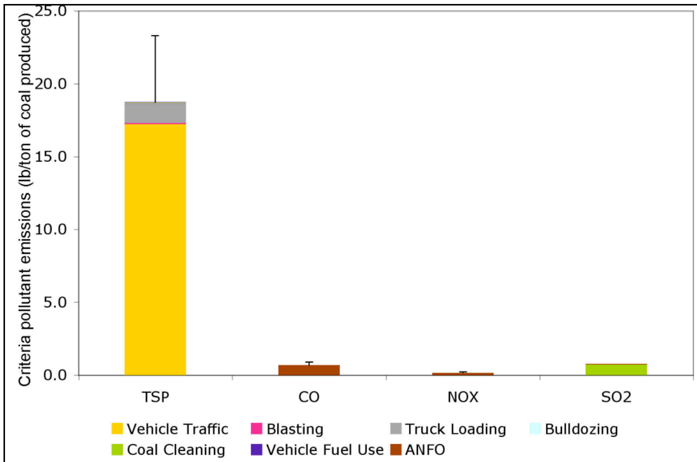
Air emissions rates are estimated by using the emissions factors described in Table 26 (and developed in Appendix C, with complete result tables). Underground mines (Figure 23) and surface mines (Figure 24) emit comparable amounts of NO_X, SO_2, (both shown in Figure 24a and Figure 24a) and CO_2 (shown in Figure 23b and 24b); coal cleaning is the main source of these emissions. Both mine types emitted most of their methane emissions during mining. Coalbed methane emissions account for 97% of underground mine methane emissions and 60% of overall greenhouse gas emissions (Figure 23b). Eighty percent of surface mine methane emissions, and 50 percent of surface mine greenhouse gas emissions are attributed to coalbed methane release (Figure 24b). Underground mine methane emissions rates are higher than surface mine methane emissions rates, because underground methane emissions factors are higher and estimated production rates are lower than estimated surface mine production rates (see Chapter 3 for estimated production rates per NCRA coalfield and region.)

The remaining discrepancies between emission rates can be explained by differences between underground and surface mines. Underground emissions factors did not include CO, which is estimated for surface mine ANFO use (Figure 24a). Surface mining is estimated to emit more TSP (which includes PM estimates) than underground mining. The TSP emissions are caused by high dust (TSP) emitting activities, vehicle traffic and truck loading (Figure 24a). Surface mining is estimated to emit more N_2O than underground mining. Underground N_2O emissions are due to electricity consumption, which emits less N_2O than surface mine diesel fuel consumption.

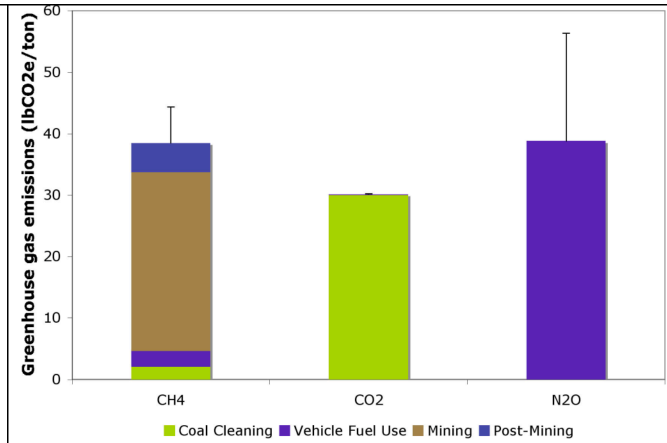


(a) Underground mine criteria pollutant emissions (b) Underground mine greenhouse gas emissions

Figure 23 Estimated underground criteria pollutant and greenhouse gas emissions. The error bar shows range for the total emissions estimate. These emissions are estimated by using the emissions factors described in Table 26.



(a) Surface mine criteria pollutant emissions



(b) Surface mine greenhouse gas emissions

Figure 24 Estimated surface mine criteria pollutant and greenhouse gas emissions. Surface mine air pollutant and greenhouse gas emissions rates varied by coalfield. The stacked column illustrates the average emissions rate. The error bar shows range for the total emissions estimate. Estimated TSP shown in (a) is includes $PM_{2.5}$ and PM_{10} emissions. These emissions are estimated by using the emission factors described in Table 26.

Based on the analysis of these emissions factors, it can be seen that the greatest sources of air pollution from coal mining are coal preparation plants, vehicle traffic, truck loading, coalbed methane, and diesel fuel consumption. The CAA already regulates coal preparation plant emissions. But if the EPA sought to expand the CAA, it could reduce dust emissions by targeting vehicle traffic and truck loading, and push for more fuel-efficient diesel-powered vehicles to limit other criteria pollutant. If the EPA were to regulate greenhouse gases, it would have to limit coalbed methane emissions and encourage diesel fuel efficiency or substitution to reduce N_2O emissions.

8.3 Coalbed methane mitigation costs

Coalbed methane accounts for a significant portion of mining greenhouse gas emissions. According to the estimates in section 8.2, it accounts for 80 percent of surface mine greenhouse gas emissions (Figure 24b) and 60 percent of underground mine emissions (Figure 23b) by mass. Reducing coalbed methane emissions would have a large impact on overall mining greenhouse gas emissions. The cost to capture coalfield methane is calculated in Appendix C and discussed in this section.

For shallow seams that may be surface mined, there may not be much methane in the coal by the time that it is mined. Due to weathering, the methane will have leaked out well before the coal is developed for mining. However, when the coal is broken, the methane stored in the coal will be released to the atmosphere. The best way to control methane emissions from surface mining is to drill and capture the methane from the coal before mining activity begins.

Methane concentration is higher in deep seams. This methane can be developed prior to and during mining operations. Current practice requires methane dilution in the ventilation air during mining for safety reasons. An alternative approach to draining methane from the mine during operation would include directional drilling to extract methane from the seam before it is cut.

Pre-mine methane mitigation focuses on its capture and use. Gob wells can be set up prior to mining, then "mined through" in order to release the gas into the well. Gob gas is inconsistent, and the well has a short life. Gob wells are historically used as a safety measure, rather than for greenhouse gas reduction. Horizontal drainage holes can be drilled into the coal seam before mining, and can be 1000' – 4000' long.

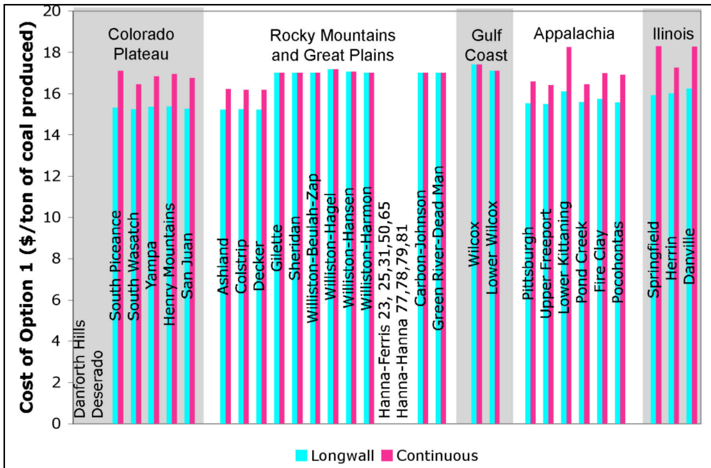
EPA well and pipe cost data are used, as is the EPA guideline of one vertical well per 40 – 160 acres area, gob wells placement at the end of longwall panel, and 200 – 400 feet spacing between horizontal wells [60]. It is probable that these wells may need to be closer together if the coal seam is not methane rich. Reduction rates assumed are provided by EPA [60]. EPA Cost and quantity estimation data for a coalfield methane development project are shown and discussed in Appendix C.

The four EPA methane development scenarios examined [61], which do not account for the commercial value of methane, are:

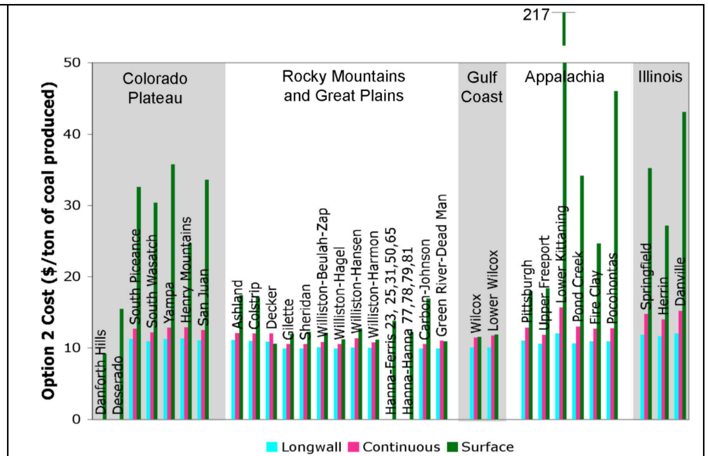
Option 1 Gob wells only, used during mine operation
Option 2 Vertical wells, used to drain methane 5 years prior to mining (this is the only option that can be applied to a surface mine.)

Option 3 Vertical wells + gob wells
Option 4 Vertical wells + gob wells + horizontal boreholes (drain seam 3 years prior to mining)

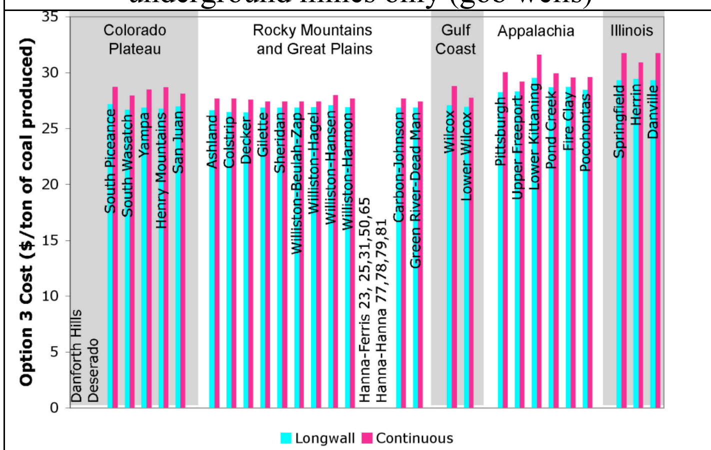
The estimated costs using the configurations of these four options, using EPA equipment costs and project sizing parameters is shown in Appendix C. The median costs per each option are shown in Figure 25. Underground methane mitigation costs are similar for all options. Options 1 and 2, as applied to underground mines, have median costs of \$15 - \$18/ton of coal produced (Figure 25a, b). Options 3 and 4, which are combination options of well and drilling options to mitigate methane, cost \$20 - \$50/ton of coal produced with median costs of approximately \$28/ton of coal produced (Figure 25c, d). Median surface mine methane mitigation costs (Figure 25b) range from \$9 to \$217/ton of coal produced. Surface mine methane emission rates are lowest (Table 27) in the Rocky Mountains and Great Plains, so the estimated control cost is lowest in that region. It is highest in Appalachia and Illinois because estimated surface mine production rates are lowest in those regions, and coalbed methane emissions are highest (Table 27). Methane capture costs are considerable, considering the price of coal. As shown in Table C29 in Appendix C, recovery efficiencies for gob, vertical and horizontal boreholes range from 50 – 70 percent. Table 28 adjusts the emission rates in Table 26 to reflect the methane recovered. These rates are 50 – 70 percent of the rates in Table 26.



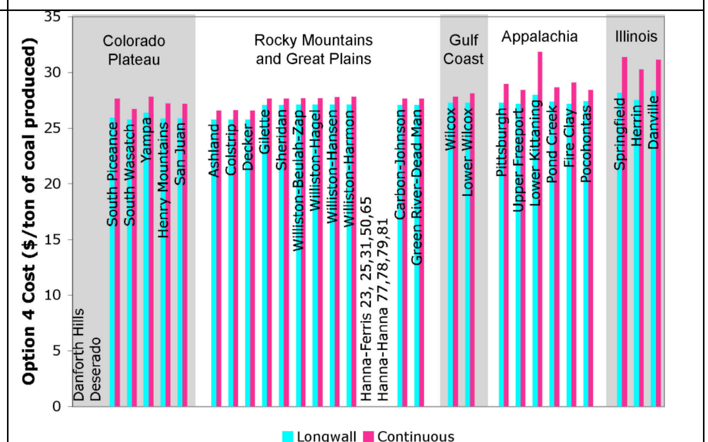
(a) Cost of methane control option 1, for underground mines only (gob wells)



(b) Cost of methane control option 2, for all mine types (vertical wells)



(c) Cost of methane control option 3, for underground mines only (vertical wells + gob wells)



(d) Cost of methane control option 4, for underground mines only (Vertical wells + gob wells + horizontal boreholes)

Figure 25 Costs of four methane control options. As discussed, options 1, 3, and 4 are suitable for underground mines only. Because the model does not simulate underground mines for Danforth Hills, Deserado, Hanna-Ferris and Hanna-Hanna, cost to implement options 1, 3, and 4 were not assessed in those coalfields.

Table 28. Estimated methane reduction rate (ft^3 methane/ton coal produced) per mine type and NCRA region based on coalbed methane emission rates and assuming 50 – 70 percent recovery by Options 1 - 4.

Region	Coalfield	Surface mine	Post mine surface	Underground[a]	Post mine under ground
Colorado Plateau	Danforth Hills, South Piceance	33 – 46	6 – 8	38 – 53	32 – 45
	Deserado, South Wasatch, Yampa, Henry Mountains	16 – 22	3 – 4	28 – 53	16 – 22
	San Juan	8 – 11	1	38 – 53	17 – 24
Rocky Mountains and Great Plains	All coalfields	6 – 8	1	38 – 53	2 – 4
Gulf Coast	All coalfields	33 – 46	6 – 8	38 – 53	21- 29
Appalachia	Pittsburgh, Upper Freeport, Lower Kittanning	60 – 83	10 – 13	44 – 62	7 – 10
	Pond Creek, Fire Clay, Pocohontas	25 – 35	4 – 6	45 – 62	65 – 91[a]
Illinois	All coalfields	35 – 48	6 – 8	28 – 32	11 – 15

[a]A new range is calculated as 50 percent of the original lower bound and 70 percent of the original upper bound.

As previously discussed, there are several coalbed methane development projects currently underway in the U.S., that develop coalbed methane in abandoned mine fields or concurrently with active underground mines. As a result, this analysis provides a low estimate of available coalbed methane. The estimated cost to develop this resource is a high estimate because it does not optimize resource development. The following comparison of the estimated breakeven coalbed methane sale price to natural gas prices and current coalbed methane sales prices shows that the estimated cost to develop methane is high.

Dividing the reduced emission rates (ft^3 methane/ton of coal) estimated in Table 28 by the methane capture costs ($/ton of coal shown in Figure 25), the breakeven price at which the methane must be sold can be determined. Assessing the best case scenario of a surface mine methane capture project in the Rocky Mountains and Great Plains, where the total methane reduction rate is 7 – 9 ft^3/ton and surface mine methane reduction costs are \$9/ton, the reduction cost is \$0.80 - \$0.90/ft^3 of methane. The breakeven cost to sell this methane is \$800 - \$900/Mcf. Alternately, a carbon tax of \$150 - \$180/tCO_2e would make methane development in the Rocky Mountains and Great Plains worthwhile. The most recent EIA Natural Gas Weekly reported that wellhead gas prices ranged \$7 - \$11/Mcf [62], which is considerably cheaper. Studies of coalbed methane costs show that it is a profitable resource to develop, at \$3 - \$7/Mcf in the Powder River Basin (Rocky Mountains and Great Plains)[63]. In comparison to this study, the estimated methane control costs are high. However, the costs in this analysis consider the cost to develop an entire mine area before mining. It also is evaluating the average cost to develop an average seam based on general NCRA coal data. In contrast, a project intended to extract coalbed methane gas for profit will target the most profitable seams rather than whichever seam is going to be mined. It can be expected that in practice, coalbed methane development costs will range from low expense (that can be sold at a price competitive with natural gas) to high expense as estimated here. Although methane can be sold to offset its development cost, it is not likely that all coalfield methane resources are suitably rich to sell as fuel. More research is needed about the methane quality per coalfield in order to judge the commercial benefit of selling methane as a fuel.

9 Cost of more stringent regulation

As discussed throughout this chapter, current mining practices affect the environment. Existing regulation is not sufficiently enforced or stringently applied. As a result, if we continue to mine coal as we have, we will significantly distress the environment. The environmental impact that will result from following that path of our current environmental regulation can be estimated by using the impact factors generated throughout this chapter for subsidence, surface mining land damage, acid mine drainage, erosion, criteria pollutants and greenhouse gas emissions. Based on the cost and technology curve generated for laissez faire coal demand in Chapter 3, the environmental damage (I) incurred to meet demand (D) is estimated (Equation 5) and reported in Table 29.

$$I = D\{\varepsilon\} \qquad (5)$$

Where I = total environmental impact
D = annual coal demand (see Chapter 3)
{ε} = set of environmental impact factors determined in this chapter:
Longwall subsidence area per ton (ft^2/ton of coal produced)
Surface mine land impact per ton (ft^2/ton of coal produced)
Erosion per ton (1000 lb of soil/ton of coal produced)
Acid generation potential (ton of acid/ton of coal produced)
Criteria pollutant emissions (lb/ton of coal produced)
Greenhouse gas emissions ($lbCO_2e$/ton of coal produced)

The cost curve to meet EIA projected business as usual demand, under laissez faire environmental regulation, is revisited in Figure 26. It shows that surface mining the Colorado Plateau and Rocky Mountains and Great Plains is the least cost method through 2040, when longwall mining in the Rocky Mountains and Great Plains accounts for most of the cheapest coal. As shown in Figure 26, if current environmental regulation does not change, coal will cost less than \$30/ton to mine over the next 70 years, and less than \$55/ton for the following 30 years.

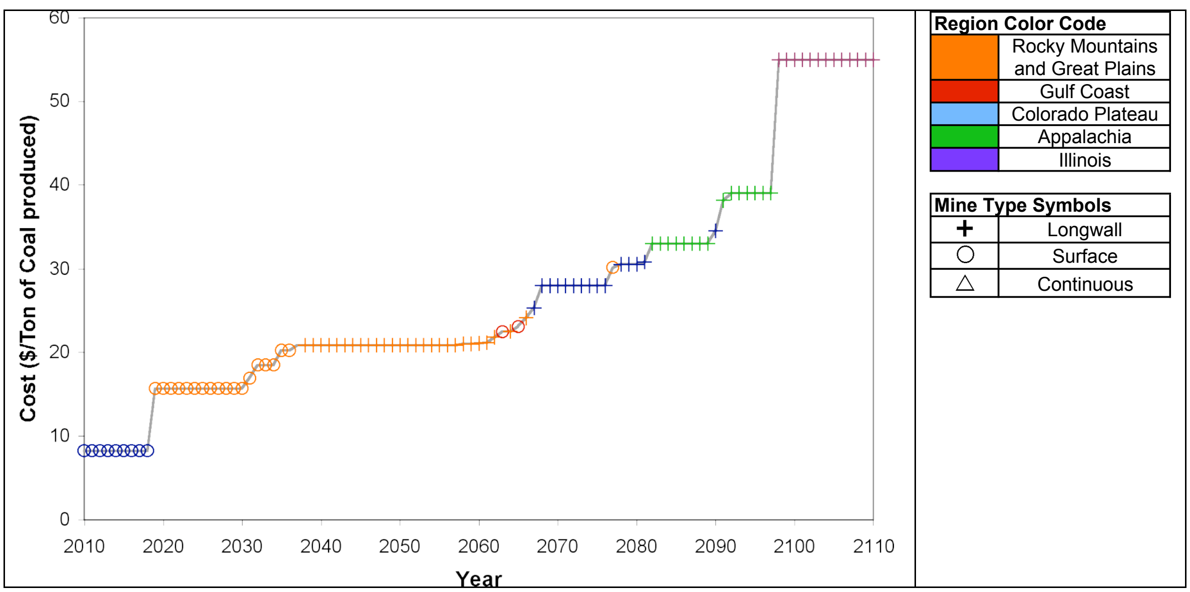


Figure 26 Laissez faire regulation mining cost curve. This is the least cost curve to meet EIA business as usual demand under current environmental regulation. The curve represents the cheapest mining option to meet demand. Mining is dominated by surface and longwall mines in the Colorado Plateau and Rocky Mountains and Great Plains. The cost to mine coal through 2080 will not exceed \$30/ton, after 2080 it will rise to \$55/ton. Reprinted from Chapter 3.

As shown in Table 29, if environmental regulation does not change, we can expect western surface mines to erode thousands of tons of soil per year and generate a lot of TSP (presumably in the form of dust emitted from vehicle use and truck loading). After

2040, when cheap surface mineable coal in the Colorado Plateau and Rocky Mountains and Great Plains regions will likely have become depleted, longwall mines will be the cheapest means to extract coal. Most of these mines will also be in the Colorado Plateau and Rocky Mountains and Great Plains regions. When longwall mines are the cheapest method to mine coal, land impact will increase 100-fold. Some environmental impacts will decrease. Carbon monoxide emissions will decrease significantly because less coal will be surface mined, so that an insignificant amount of ANFO will be used. Moreover, TSP emissions will fall because there will be less surface mine vehicle travel and truck loading. Nonetheless, total environmental impact will increase over time because coal demand will increase.

Table 29. Annual environmental impact of laissez faire regulation

Year	Water Acidification (Billion Tons)	Land Impact (Acres)	Subsidence Depth (Feet)	Soil Erosion (Tons Soil)	PM (Thousand Tons)	NO_X (Thousand Tons)	SO_2 (Thousand Tons)	CO (Thousand Tons)	Greenhouse Gas (Million tons CO_2e)
2010	31	182	0	1,002	946	433	433	2	52
2020	20	10,082	0	5,131	1,018	504	504	18	29
2030	23	11,394	0	5,799	1,150	570	570	20	32
2040	26	11,960	73	824	25	142	516	0	81
2050	28	13,194	73	909	28	157	569	0	90
2060	31	16,302	24	3,399	31	172	622	0	98
2070	58	31,829	8	9,539	33	187	675	0	131
2080	161	33,235	7	54,801	36	203	765	0	135
2090	173	109,192	5	83,549	39	223	840	0	202
2100	306	109,654	4	136,286	41	250	957	0	129
2110	326	116,644	4	144,973	44	266	1,019	0	137

Total cost ranges, for longwall, continuous, and surface mining, are shown in Table 31 - Table 33. The *low* cost is that associated with the least cost method to mitigate environmental damage, while the *high* cost is that associated with the most expensive method.

It is tempting to say that the *high* cost represents the best treatment option, and the *low* cost represents the worst treatment option available. This assumption is incorrect. First, selection of various treatment methods will be site specific. Second, the long-term performance of these technologies is not known. For example, the long-term physical and chemical stability of backfilling material is not known with certainty. While all examined fill materials promise to mitigate subsidence, its ability to support overlying strata without disrupting or polluting groundwater over the long term is not known. Third, a serious U.S. research and development program focused on abatement technologies and strategies could result in cost reductions.

If we want to change the environmental outcome of our continued coal dependence, then we must reconsider its regulation. As discussed in Chapter 3, coal demand may increase for a number of reasons, whether for additional domestic use such as electricity generation and liquid fuels, or for the export market. In either case, regardless of where the coal will be used, if demand increases we can expect environmental impact to increase. Therefore, it is imperative to consider how environmental impacts can be reduced through regulation.

Two possible scenarios of additional environmental regulation are evaluated. A comparison of the two scenarios is shown in Table 30. The first is the possibility that only the SMCRA is more stringently applied and enforced. It is the cost of mining in the case that the SMCRA is applied as it was intended, with the addition that it mandates damage prevention in addition to reclamation. This scenario assumes that the SMCRA will mandate acid mine drainage and subsidence prevention, restoration to "approximate original contour" and original land use. It does not expand CAA to regulate dust or methane emissions, or interpret CWA section 404 to outlaw mine spoil disposal in surface water bodies. The second scenario adds CAA and CWA enforcement plus methane regulation to the first scenario. Under this scenario, it is possible that environmental regulations are so strictly enforced that surface mines are not permitted, due to rigid interpretation of the SMCRA "approximate original contour" stipulation and the CWA 404 definition of suitable fill. In this case, the analysis only allows surface mining in four western coalfields, for which the model is unable to simulate underground mines. In all other regions, the lowest cost underground mine option is substituted for surface mining, complete with backfilling.

Table 30. Regulatory scenarios and issues addressed.

Regulatory issue	Scenario 1 More Stringent SMCRA	Scenario 2 More Stringent SMCRA, CWA, and CAA
SMCRA mandates subsidence prevention, in addition to subsidence reparation. The analysis evaluates underground mine backfilling cost.	X	X
SMCRA no longer allows exemptions to the stipulation that surface mined land must be reclaimed to their original use. The analysis evaluates the reforestation and revegetation costs.	X	X
SMCRA requires erosion prevention during mining. The analysis includes soil replacement cost.	X	X
SMCRA mandates acid mine drainage prevention. The analysis evaluates the cost to coat exposed coal.	X	X
SMCRA mandates absolute "approximate original contour" restoration, essentially outlawing mountaintop removal. The analysis addresses this by examining the cost to restrict surface mining.	X	X
CWA 404 forbids surface mine spoil disposal in surface water bodies, which would outlaw a practice common to mountaintop removal. The analysis addresses this by examining the cost to restrict surface mining.		X
EPA regulates greenhouse gases, including coalbed methane emissions. The analysis evaluates coalbed methane capture costs.		X
EPA expands CAA to regulate surface mine PM emissions. The analysis addresses this by examining the cost of restricting surface mining.		X

Table 31 Longwall median total cost ($/Ton). All costs shown in this table are median estimates. The range of methane costs reflects the least cost choice (Option 2, premining vertical wells), and highest cost choices (Options 3 or 4). The subsidence cost range of fracture fill and gob fill are dependent on material costs. The low cost is associated with CCR fill and high cost is Portland cement fill. Scenario 1 = column A (non-robot cost) + column C + column D + column E. Scenario 2 = column A (robot and non-robot cost) + column B + column D + column E.

Region	Coal Seam	Base Cost (Robot Cost) A	Methane B		Subsidence C				AMD D	Erosion E	Scenario 1: SMCRA		Scenario 2: SMCRA, CWA, CAA (Robot cost)	
					Fracture Fill		Gob Fill							
			Low	High	Low	High	Low	High			Low	High	Low	High
Colorado Plateau	South Piceance	31 (25)	11	27	5	39	7	52	4	9.E-05	39	87	51 (45)	114 (108)
	South Wasatch	25 (20)	11	27	5	41	7	52	4	6.E-05	34	81	45 (40)	108 (103)
	Yampa	31 (25)	11	27	5	41	7	52	4	9.E-05	40	87	51 (45)	114 (107)
	Henry Mountains	35 (27)	11	27	5	37	7	52	4	8.E-05	43	91	54(46)	117 (109)
	San Juan	28 (22)	11	27	5	40	7	52	4	8.E-05	37	84	48 (42)	111 (105)
Rocky Mountains and Great Plains	Ashland	21 (17)	11	27	13	97	7	52	9	2.E-05	37	127	48 (44)	154 (150)
	Colstrip	23 (18)	11	26	7	51	7	52	5	4.E-05	35	80	46 (41)	107 (102)
	Decker	21 (17)	11	26	20	153	7	52	17	1.E-05	44	191	55 (51)	217 (213)
	Gillette	21 (17)	10	27	30	200	7	52	21	9.E-06	48	241	58 (54)	268 (264)
	Sheridan	21 (17)	10	27	24	178	7	52	19	1.E-05	47	218	57 (53)	245 (241)
	Williston-Beulah-Zap	22 (17)	10	27	6	43	7	52	5	4.E-05	33	79	43 (38)	106 (102)
	Williston-Hagel	22 (17)	10	27	5	38	7	52	5	4.E-05	32	79	42 (38)	106 (102)
	Williston-Hansen	24 (19)	10	27	5	39	7	52	5	5.E-05	34	81	44 (39)	108 (103)
	Williston-Harmon	22 (18)	10	27	5	39	7	52	5	4.E-05	32	79	42 (38)	106 (102)
	Carbon-Johnson	21 (17)	10	27	7	56	7	52	8	3.E-05	35	85	45 (41)	112 (108)
	Green River-Dead Man	22 (17)	10	27	7	52	7	52	6	4.E-05	35	80	45 (40)	107 (103)
Gulf Coast	Wilcox	25 (19)	10	27	4	35	7	52	5	NA	34	82	44 (39)	109 (104)
	Lower Wilcox	25 (20)	10	27	5	35	7	52	5	NA	35	82	45 (39)	110 (104)
Appalachia	Pittsburgh	39 (32)	11	28	4	32	7	52	4	6.E-04	47	95	58 (51)	123 (104)
	Upper Freeport	33 (25)	11	28	4	34	7	52	4	4.E-04	41	89	52 (44)	117 (117)
	Lower Kittanning	88 (66)	12	30	6	46	7	52	4	1.E-03	97	144	109 (87)	173 (151)
	Pond Creek	39 (32)	11	29	5	39	7	52	4	6.E-04	48	95	58 (51)	124 (117)
	Fire Clay	38 (30)	11	29	5	34	7	52	4	6.E-04	47	94	58 (49)	123 (114)
	Pocohontas	39 (30)	11	28	5	40	7	52	4	6.E-04	47	95	58 (50)	123 (114)
Illinois	Springfield	80 (63)	12	29	4	36	7	52	4	1.E-03	88	136	100 (83)	165 (148)
	Herrin	55 (43)	12	29	5	35	7	52	4	9.E-04	63	111	75 (63)	140 (128)
	Danville	79 (61)	12	29	4	34	7	52	4	1.E-03	87	135	100 (81)	165 (147)

Table 32. Continuous mine total costs ($/Ton) All costs shown in this table are median estimates. The range of methane costs reflects the least cost choice (Option 2, premining vertical wells), and highest cost choices (Options 3 or 4). The subsidence cost range of fracture fill and gob fill are dependent on material costs. The low cost is associated with CCR fill and high cost is Portland cement fill. Scenario 1 = column A + column C + column D + column E. Scenario 2 = column A + column B + column D + column E.

Region	Coal seam	Base Cost A	Methane B		Subsidence C				AMD D	Erosion E	Scenario 1 SMCRA		Scenario 2: SMCRA, CWA, CAA	
					Fracture Fill		Gob Fill							
			Low	High	Low	High	Low	High			Low	High	Low	High
Colorado Plateau	South Piceance	35	13	29	0	34	7	52	1	1.E-05	37	88	50	117
	South Wasatch	30	12	28	0	36	7	52	1	7.E-06	31	83	44	111
	Yampa	35	13	28	0	36	7	52	1	1.E-05	37	88	50	117
	Henry Mountains	38	13	29	0	32	7	52	1	1.E-05	39	91	52	120
	San Juan	32	12	28	0	34	7	52	1	1.E-05	34	85	46	113
Rocky Mountains and Great Plains	Ashland	27	12	28	1	88	7	52	4	2.E-06	32	119	44	147
	Colstrip	29	12	28	0	42	7	52	1	5.E-06	30	82	42	109
	Decker	27	12	28	2	137	7	52	3	1.E-06	31	166	43	194
	Gillette	27	11	28	2	198	7	52	7	1.E-06	35	232	46	260
	Sheridan	27	11	28	1	159	7	52	6	1.E-06	34	192	44	220
	Williston-Beulah-Zap	27	11	28	1	40	7	52	1	5.E-06	29	80	40	108
	Williston-Hagel	27	11	28	1	36	7	52	0	5.E-06	28	80	39	107
	Williston-Hansen	29	11	28	1	38	7	52	1	5.E-06	30	81	41	109
	Williston-Harmon	28	11	28	1	37	7	52	1	4.E-06	29	80	40	108
	Carbon-Johnson	27	11	28	1	44	7	52	1	3.E-06	28	79	39	107
	Green River-Dead Man	28	11	28	1	46	7	52	1	4.E-06	29	81	40	108
Gulf Coast	Wilcox	30	11	29	1	35	7	52	0	NA	31	82	42	110
	Lower Wilcox	30	12	28	1	35	7	52	0	NA	31	82	43	110
Appalachia	Pittsburgh	43	13	30	0	30	7	52	1	8.E-05	44	95	57	125
	Upper Freeport	36	12	29	0	33	7	52	1	6.E-05	38	89	49	118
	Lower Kittanning	80	16	32	0	46	7	52	3	2.E-04	84	135	100	167
	Pond Creek	43	13	30	0	34	7	52	1	8.E-05	45	96	58	126
	Fire Clay	40	13	30	0	32	7	52	1	7.E-05	41	93	54	122
	Pocohontas	45	13	30	0	34	7	52	1	8.E-05	47	98	59	128
Illinois	Springfield	76	15	32	0	34	7	52	2	2.E-04	78	130	93	161
	Herrin	58	14	31	0	30	7	52	1	1.E-04	59	111	73	142
	Danville	76	15	32	0	33	7	52	2	2.E-04	78	130	93	161

Table 33. Surface mine environmental costs ($/Ton) All costs shown in this table are median estimates. Methane capture costs are the premine vertical well development (Options 2). The range of AMD treatment costs reflects the least cost choice (landfill liner), and highest cost choice (sealant). Scenario 1 = Column A + Column C + Column D + Column E, Scenario 2: Column A + Column B + Column C + Column D + Column E

Region	Coal seam	Base Cost A	Methane B	AMD C		Revegetation D	Erosion E	Scenario 1: SMCRA		Scenario 2: SMCRA, CWA, CAA	
				Low	High			Low	High	Low	High
Colorado Plateau	Danforth Hills	8	9	0	1	0.0	5.E-06	8	10	18	19
	Deserado	64	15	1	10	0.1	3.E-04	65	74	80	90
	South Piceance	321	33	7	77	0.3	6.E-04	329	398	361	431
	South Wasatch	319	30	6	53	0.2	5.E-04	325	372	355	402
	Yampa	422	36	7	64	0.3	7.E-04	429	486	465	521
	Henry Mountains	235	25	4	36	0.3	8.E-04	239	272	264	296
	San Juan	349	34	9	64	0.2	6.E-04	358	413	391	446
Rocky Mountains and Great Plains	Ashland	92	17	1	10	0.1	1.E-04	93	102	111	119
	Colstrip	63	17	1	11	0.1	3.E-04	64	74	81	91
	Decker	16	11	0	2	0.0	7.E-05	16	18	27	29
	Gillette	32	12	0	4	0.0	6.E-05	32	36	44	48
	Sheridan	34	12	1	5	0.0	7.E-05	35	39	47	51
	Williston-Beulah-Zap	34	12	1	5	0.1	3.E-04	35	40	47	52
	Williston-Hagel	20	11	0	3	0.1	3.E-04	21	23	32	35
	Williston-Hansen	38	13	1	7	0.2	3.E-04	39	46	52	58
	Williston-Harmon	18	11	0	4	0.1	3.E-04	19	23	30	34
	Hanna-Ferris 23,25,31,50,65	69	14	1	12	0.0	9.E-05	70	81	84	95
	Hanna-Hanna 7,78, 79, 81	30	12	0	4	0.0	4.E-05	31	35	43	47
	Carbon-Johnson	99	17	2	21	0.1	2.E-04	101	120	118	136
	Green River-Dead Man	17	11	0	3	0.1	2.E-04	17	20	28	30
Gulf Coast	Wilcox	23	12	0	3	0.2	NA	24	27	35	38
	Lower Wilcox	22	12	0	4	0.2	NA	23	26	35	38
Appalachia	Pittsburgh	133	18	2	17	0.4	4.E-03	135	150	153	168
	Upper Freeport	132	18	3	25	0.3	3.E-03	135	157	153	175
	Lower Kittanning	3283	217	76	727	0.9	1.E-02	3360	4011	3576	4227
	Pond Creek	389	34	8	70	0.4	5.E-03	397	460	431	493
	Fire Clay	204	25	3	33	0.3	4.E-03	208	238	232	262
	Pocohontas	451	46	11	101	0.4	4.E-03	462	552	507	598
Illinois	Springfield	461	35	9	93	0.8	1.E-02	470	555	505	589
	Herrin	204	27	5	49	0.5	7.E-03	210	253	237	280
	Danville	485	43	7	2287	0.9	1.E-04	493	2773	535	2815

The method used in Chapter 3 can be used to create least cost curves in order to assess the monetary effect that more stringent regulation will have on mining costs. The least cost mining method in each coalfield is selected from the results shown in Table 31 - Table 33. Cost curves based on the low and high bound are generated. The least cost mining methods per low and high cost case are selected per each region. For example, when the Scenario 1 lower bound of prevention costs is considered, the least cost method to mine the Gillette coalfield (Rocky Mountains and Great Plains) is surface mining, which will cost $44/ton (Table 9). In the case that surface mining is not permissible, then continuous mining would be the least cost choice at $46/ton (Table 8). Recall that surface mining could be impossible to undertake if section 404 of the CWA, which forbids filling surface waters with mine spoil, or if the SMCRA "approximate original contour" requirement were strictly enforced. If the higher bound of prevention cost is considered, then surface mining remains the cheapest mining method in the Gillette coalfield ($48/ton), followed by continuous mining ($260/ton). After choosing the least cost method to mine, considering high and low cost cases, the regions are scheduled according to cost to meet EIA projected demand. The low and high total cost curves are compared to the laissez faire environmental regulation cost curve in Figure 27 and Figure 28.

The uncertainty associated with the total estimated costs is high. This analysis is based on generalizations of coal quality and geology. As a result, subsidence, acid generation potential, erosion, criteria pollutant and greenhouse gas emissions may be over or underestimated. Moreover, an exhaustive list of technologies was not identified. A research program that focuses on mining's environmental impact would address these uncertainties. It would examine mining's effect on the environment throughout the country. It would also revisit the control technologies evaluated in this thesis, as well as develop alternate options that may be cheaper and/or more effective. At this time, there is very little U.S. research focusing on mining innovation, but the need to responsibly develop coal resources points to the need for a serious research program.

Figure 27 compares mining costs under Scenario 1 to the laissez faire cost curve, assuming that mining will still be scheduled to meet EIA business as usual demand. In this scenario, conventional surface mining continues. Environmental surface mine land costs are revegetation costs. As a result, surface mining continues to be the cheapest extraction method. As shown in Figure 27, in contrast to the costs under laissez faire regulatory enforcement where longwall mining overtakes surface mining as least cost mining option in 2040, surface mining remains the cheapest mining method through 2080. There is little difference between low and high total costs until 2080, when cheap surface mineable coal is depleted. After inexpensive surface mineable coal is depleted in Scenario 1, continuous mines are the next cheapest option. Longwall mining is the most expensive underground mining option.

If subsidence is strictly forbidden, longwall mining cost increases so much due to the additional cost to backfill, that low yielding continuous mines are cheaper. The Scenario 1 low cost curve in Figure 27 shows that Appalachian continuous mines come on line as the cheapest coal supply option in 2080. Illinois continuous mines follow the Appalachian mines. The Scenario 1 high cost curve indicates that longwall mining can still be pursued – at a cost. Longwall mining with backfill and grouting will double the cost of coal. The additional cost to backfill and coat exposed coal is more expensive in thick seams like those in the western coal regions. When these preventive costs are added, they make western longwall mining so expensive that surface mines are competitive at the depths that are typically mined by underground methods.

Overall, increasing the SMCRA stringency as defined in Scenario 1 will not affect coal mining costs until 2040. In 2040, the richest surface mineable seams are depleted; the production rate for these seams is so high that the environmental cost per ton of coal produced is negligible. After 2040, mining costs under a stricter SMCRA will double. In 2080, depending on environmental control technology chosen to mitigate the impacts of underground mining, extraction costs could increase three or six fold compared to the cost under current SMCRA regulation and enforcement.

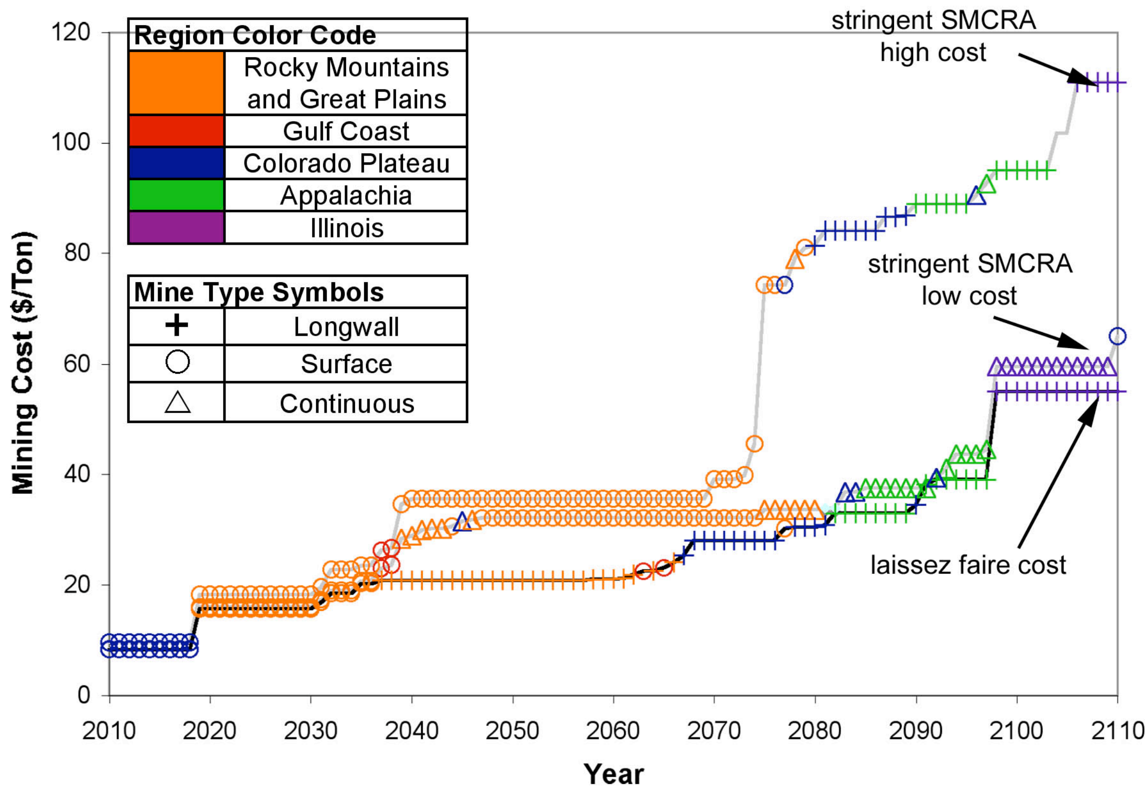


Figure 27. Comparison of scenario 1 mining costs to laissez faire cost. Scenario 1 examines more stringent SMCRA. The low cost curve represents the cost of using the cheapest environmental control technology available, and the high cost curve represents the cost of using the most expensive environmental control technology.

Increasing SMCRA stringency will not affect coal mining costs, as shown in Figure 27, for the first 30 years of the estimated cost curves. However Figure 28 shows that applying the CAA and CWA to mining, in addition to the SMCRA, will cause coal mining costs to increase two to five times the estimated cost under laissez faire regulation. In addition, given the added restrictions to coal mining – strict adherence to the SMCRA "approximate original contour" requirement, CAA regulated dust emissions from vehicle travel and truck loading, and CWA limitations on coal spoil disposal in surface water bodies – there is no coal mining undertaken after 2020. The surface mines in the first 10 years of the Scenario 2 analysis are in the coalfields where the model can't simulate underground mining. Although the model designates a few coalfields as surface mineable only, and thus cheap to mine, the overall result shows that with additional environmental regulation mining will shift from surface mining to underground mining.

The cheapest options will be continuous mining or robotic longwall mining, as shown on the Scenario 2 low cost curve.

If the SMCRA "approximate original contour" restoration requirement and the CWA 404 restriction on mine spoil disposal in surface water bodies are strictly enforced, surface mines in western coal regions are no longer suitable least cost substitutes for western longwall mines. Underground mines in Appalachia and Illinois become competitively priced to mine. On the high cost curve, Appalachian and Illinois continuous mines come on line in 2045, and 2055 on the low cost curve. The large difference between the estimated high and low costs shows that there is significant uncertainty in the cost to prevent environmental impacts from mining by using the technologies chosen.

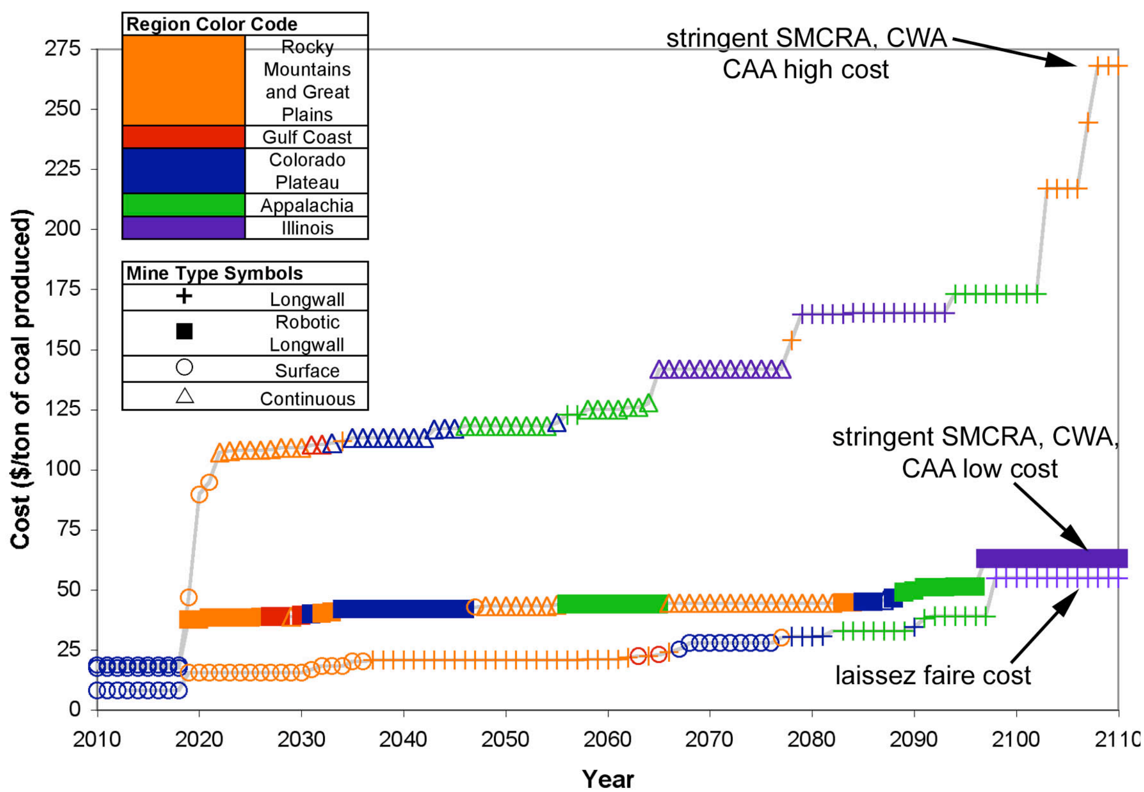


Figure 28. Comparison of scenario 2 and laissez faire mining costs. Scenario 2 examines the cost of implementing more stringent SMCRA, CWA and CAA. The low cost curve represents the cost of using the cheapest environmental protection technology available, and the high cost curve represents the cost of using the most expensive environmental protection technology available.

10 Uncertainty associated with estimated impacts and costs

The analysis in this chapter assumes the worst case environmental impact, resulting in somewhat higher estimates of impact magnitude than might occur in some settings. The cost analysis is limited by the fact that very little work has been done on developing mitigation methods, especially in the US. Many of the values are based on order-of magnitude estimates I have developed, and so results in mitigation costs that may be higher or lower than they would be in practice. The analysis assumes that maximum environmental impact will occur. The model evaluates total subsidence for underground mines, assumes that surface mine pits will be challenging to restore to their original topography, maximum soil exposure and erosion, all sulfur in unmined coal will be transformed into hydrosulfuric acid, and all coalbed methane will be released from coal seams upon extracting them. Following on this, the control costs are dependent on available cost data. In the case of backfill technology for underground mines and restoration of surface mine pits, limited cost data are available but the estimated cost ranges should be appropriate. In the case of estimated robotic longwall costs, the estimated cost is low because the technology is not commercialized yet. It can be assumed that the manufacturer will increase the cost of underground mining equipment to reflect more than the additional cost of a guidance system. In the case of erosion control, the estimated cost is also low. Although the USDA estimates that soil replacement cost is \$19/ton, it also notes that the cost to restore soil to its original condition is beyond valuation. The estimated cost to mitigate acid mine drainage by installing landfill liners, applying sealants or coating, is high. The costs calculated in this analysis are based on the retail prices of these materials, but it is likely that a mine operator would buy the materials in bulk and negotiate a lower price with a supplier. As discussed in Section 8.3, the estimated coalbed methane control costs are high because estimated coalbed methane availability is high and its development is not optimized. In short, estimated environmental impacts are high, and cost estimate certainty varies. Underground mine subsidence control and surface pit restoration by regrading, revegetation and reforestation are suitably estimated. Robotic underground mining methods, and erosion costs reported in this chapter are low estimates. Finally, acid mine drainage and methane abatement costs are high estimates.

11 Discussion

This chapter has examined some of the implications of applying more stringent environmental regulation to coal mines. The SMCRA should be updated to reflect current environmental concerns, make damage prevention a priority and be fully enforced. As shown in my environmental analysis, if coal mining practices do not change we can expect to have thousands of additional acres of land subsidence, lose thousands of tons of soil to erosion, and generate as much as several billion tons of acid that could leach into our surface and ground waters. Moreover, air pollutant and greenhouse gas emissions are not insignificant.

Most of these adverse impacts need not occur. Technologies and strategies exist, or can be developed, to eliminate or dramatically reduce such impacts. Most of the future land damage and water quality impingement would disappear if we applied fully and enforced the SMCRA and relevant sections of the CWA. We could further improve coal mine performance by applying the CWA without debate over the definition of mine spoil as a waste. And we could apply the CAA to reduce mining's dust contributions to regional haze. Furthermore, if greenhouse gases are regulated, we could control coalbed methane emissions and reduce N_2O emissions by reducing diesel fuel use at surface mine sites.

As shown in my Scenario 1 analysis, enforcing the SMCRA as it is written, and making subsidence and acid mine drainage prevention a requirement should not significantly increase coal mining costs for the next 30 years, if applied today. We would have those thirty years to invest in research, development and demonstration of technological solutions that are more cost effective than those suggested in this chapter, including improved underground backfill technology and better sealants for acid mine drainage prevention.

Scenario 2 calls for SMCRA and the CWA to be enforced without exemptions, the CAA to be applied as appropriate, and greenhouse gases to be regulated if environmental regulation is passed. This scenario has a greater effect on estimated coal mining costs than Scenario 1. If we chose this regulatory path, it could be expensive.

Both scenario analyses project changes in mine technology choice. Oftentimes, continuous mining was the least cost mining method. It has a smaller subsidence footprint than longwall mining. However, continuous mining is the least productive mining method; it leaves a lot of coal behind, so that less resource is recovered than if longwall or surface mining were used. If we plan to continue using coal, and mine it in an environmentally responsible manner, we must identify control technologies that complement high extraction mining methods. Research is needed to understand our technological options and the fundamental relationship between coal mining and the environment

11.1 Research Needs

The analysis in this chapter provides a rough estimate of the range of costs that will likely be incurred to avoid damage that will otherwise occur if coal is mined in accordance with current industry and regulatory practice. While there has been some research on the environmental impacts of coal extraction, much more needs to be done to develop robust predictive models. There has been almost *no* research in the US, and only modest efforts in Australia and Germany, to develop, test, and refine new cost-effective technologies to reduce or eliminate impacts such as subsidence and the production of acid waters.

To improve understanding of mining impacts studies are needed to allow better estimates of:

- Subsidence factors developed from measured subsidence throughout the U.S., to better predict future subsidence profiles.
- Groundwater location relative to coalfields, in order to understand how coal mining may interrupt or acidify local water.
- Regional precipitation, groundwater recharge, and groundwater flow models to better predict potential acid mine drainage.
- Water consumption by process, which would allow planners to identify areas in the mine where water use can be reduced.

These data may be collected on a regional basis, or coalfield quadrangle (see Chapter 3 for definition.) However, to improve our understanding of environmental conditions in coalfields, we should apply advanced technologies such as remote sensing to coalfields. As discussed in Chapter 3, remote sensing can provide a picture of geological qualities with greater resolution than the conventional method of borehole sampling. Detailed measurements will support the development of performance-based regulation. As discussed in Section 2.2.1, the SMCRA defines qualitative restoration standards such as "approximate original contour," "subsidence in a predictable and controlled manner." By obtaining detailed information about a coalfield's geology regulatory standards can be revised to reflect our understanding of mining impact on the environment, such as how subsidence will occur. It will also serve as the basis for scientific standards and measuring compliance with regulation, such as measuring true original contour and thus being able to assess its restoration.

To improve operations planning and mine performance and reduce costs, there is a need to develop more advanced mining systems and understand how they affect mine performance and the environment. As shown in the construction of the total cost curves, equipment cost and performance can significantly affect resource development decisions. If environmental costs are ignored, surface and longwall mines will be developed in the western coal basins. When environmental costs are considered, the extraction cost rises sharply after surface minable coal is depleted. Appalachian and Illinois coal is less environmentally expensive to extract than a lot of the western coal. However, with more advanced technology or management techniques, the total cost of coal in the Colorado Plateau and Rocky Mountains and Great Plains could decrease and be competitive against eastern coal.

The most urgent need is for a coordinated national research effort to develop, refine and deploy cost-effective technologies and strategies that can dramatically reduce mining's environmental impacts. In approximate order of priority, research needs include:

- Mitigation techniques for mountain top removal. One possibility, examined in Section 5.3, is to substitute robotic underground mines for surface mines. To confidently substitute robotic underground mines for surface this technology must demonstrate that it is robust and safe to leave unattended. With more demonstration data, widespread implementation costs can be estimated with more precision. A second possibility is to create more waste management options for surface mines. An alternative to substituting robotic underground mines for surface mines is to determine an extraction method that minimizes surface mine footprint by managing spoil and waste more efficiently.

- Mine backfill applied to coal mines. This technology is discussed in Section 4.1.1. Although there are many reports of backfilling for non-coal mines, it is essential to demonstrate the success this technology in U.S. coal mines. As a result, we will be able to assess long term backfill structural performance and groundwater effects and determine whether this technology is a suitable subsidence solution.
- Acid mine drainage prevention and monitoring, to protect water quality. Section 7.1 recommends the use of coatings to reduce acid generation and drainage. However, there may be other means to prevent acid generation. Moreover, there is a need to improve long term monitoring of closed mines, so that if acid is formed a swift response can be deployed.
- Soil erosion management techniques, and related costs, that do not permanently disfigure the surface. Soil replacement, discussed in Section 6.3, will restore eroded land. However, if we seek to prevent or manage erosion, soil reinforcement techniques from industrial applications such as highway and road management could be applied to mining. However, these techniques include trenches to reroute water flow, and gravel reinforcement of slopes – while potent approaches, would detract from environmental aesthetic.
- Reduce coalbed methane emissions. As discussed in Section 8.3, coalbed methane can be developed before and during mining. At this time, the economic viability of coalbed methane and its potential to negate its development costs are not certain. While the analysis found an example where coalbed methane development costs are competitive with natural gas prices, additional analysis of methane content in coal seams is needed in order to ascertain the widespread potential for commercial development.
- Reduce criteria air pollutant and greenhouse gas emissions by improving surface mine dust suppression and vehicle fuel efficiency. As shown in Section 8.2, surface mines generate a lot of dust. Surface mine vehicle fuel use emits a lot of greenhouse gases. Developing techniques to manage dust, as well as creating low emission mining vehicles are steps towards reducing mining's air quality impact.

Even in a carbon-constrained future, coal will remain an important fuel. The top ranked mining concerns are irreversible impacts that will have a significant impact on the environment. Mountain top removal is an irreversible process. Induced instability from mine subsidence will prohibit future construction and growth. Topsoil loss will denude the landscape, and acidification will diminish our fresh water resources. Finally, mining will contribute to local and global pollution by emitting criteria pollutants and greenhouse gases.

While this chapter has identified and assessed a number of land use impacts, air and water pollutant emissions, and greenhouse gases, with further analysis, additional issues may be defined.

The recent NAS report recommends that $60 million per year be spent to supplement the $10 million allowance spent on "research necessary to adequately respond to the environmental impacts of the past, existing, and future mining operations" [64]. Updating the SMCRA amendment budget from 1994 dollars to 2007 dollars[5], I estimate that a research program would be suitably funded for $50 - $60 million per year. This budget would cover fundamental research, as well as demonstration projects in the field. Assuming that a demonstration project could cost from $0.5 - $1 million with industry cost sharing via equipment prototyping and labor, multiple projects could be undertaken throughout the NCRA regions. This program should be a permanent program, rather than a 4-year initiative, with its budget updated as needed.

I recommend that OSM lead this expanded research effort. However, to avoid more "business as usual" a high level technical advisory board should be created to help plan and direct the program to develop technologies and strategies to limit the environmental impacts of coal extraction. The program should be a focused national effort designed to

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[5] The SMCRA was amended in 1988 to initiate coal mine research and innovation at universities and institutions by providing 4 years (1990 – 1994) of funding. The amendment allotted $15 million per year for institutional research, and $400,000 per year per state to disburse among public universities. Assuming that all 50 states received $400,000, annual coal research funding for universities was $20 million per year. In all, the SMCRA amendment provided $35 million per year from 1990 – 1994, to research institutions and universities programs. Despite my best efforts, I could not find any work resulting from these efforts that addressed seriously the issues discussed in this Chapter. Average 1994 consumer price index (CPI) is 148.2, and average 2007 CPI is 207.34. 65. Bureau of Labor Statistics. *Consumer Items Indexes and Annual Percent Changes from 1913 - Present*. 2007 [cited 2008 November 24, 2008]; Available from: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.

engage the best investigators on the most carefully developed research plans. It should not simply spread small amounts of money around as "entitlements" across programs and institutions in many different states. OSM should develop partnerships with other agencies, private sector, research universities, and other research institutions. It should organize research that will lead to better understanding of environmental impacts as well as the development and deployment of control technologies. It should collaborate with EPA and other relevant government agencies, to ensure that environmental goals are consistent and agency efforts are not redundant. Such a research program would improve the understanding of coal mining's relationship with the environment, and develop technologies to mitigate negative impacts.

If the nation is to reduce CO_2 emissions by 50-80% in a cost-effective way by the middle of this century, it is difficult to see how that can be achieved without a portfolio of energy technologies that includes continued, perhaps even expanded, use of coal with carbon capture and deep geological sequestration. We should not be destroying local and regional environmental quality in order to fix a global environmental problem. This thesis has demonstrated that we don't have to, if we get serious now about addressing the externalities of coal extraction.

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Chapter 5: Conclusions and Recommendations

The goal of this dissertation is to elucidate the cost of U.S. coal mining under technological and environmental uncertainty. It builds upon the recent National Academy of Science (NAS) report on coal research and development [1]. The results of this analysis agree with the NAS report in several respects. Estimates of coal resource availability, recovery and mining environmental impacts included in the NAS report are uncertain and I provide a detailed analysis of these issues in order to eliminate some of this uncertainty. To this end, I estimate available supply and cost, mining impact on the environment, and how the industry's environmental performance can be improved. As outlined in the Introduction, Chapter 2 described the construction and validation of a coal mine model that was used to estimate future U.S. mining costs in Chapter 3, and was expanded in Chapter 4 to evaluate environmental impacts and costs.

The analysis shows that there is considerable uncertainty associated with coal resource availability and whether it is sufficient to meet demand. The estimate determined in Chapter 3 is on the low side because it is based on the National Coal Resource Assessment (NCRA), which does not report all coal resources. Based on current extraction methods, there are 250 – 320 billion tons of coals available. If projected coal demand increases at a faster rate compared to business as usual expected demand, it is possible that we may run out of coal earlier than the generally accepted 250 year time frame. If coal demand matches Energy Information Administration (EIA) high coal demand forecasts, such as the restricted natural gas and oil supply case and stagnant 2008 energy efficiency case, we may deplete our available resource within 100 years. The analysis also shows increasing uncertainty associated with estimated supply costs over the 100 year evaluation period. While the estimated cost range in the first 10 years is small, it increases such that at the end of the period, estimated cost is \$20 - \$95/ton (median estimate is \$55/ton.) These estimated mining costs are low because the model optimizes extraction without considering coal quality and transportation costs (see Chapter 3.) However, the large range in estimated fuel cost creates uncertainty in future coal-fired electricity generation costs and the cost to use coal for other applications. To reduce this uncertainty, it is important to develop technologies that can cost effectively extract coal from thin and deep seams within the next 50 years.

In addition to demonstrating supply and cost uncertainty, the analysis shows that the environmental impacts of continuing our current course of environmental regulation are significant. As shown in my environmental analysis, if coal mining practices do not change we can expect to have thousands of additional acres of land subsidence, lose thousands of tons of soil to erosion, and generate as much as several billion tons of acid that could leach into our surface and ground waters. Moreover, air pollutant and greenhouse gas emissions are not insignificant. My estimates of environmental impact are high, because I assume that this impact is inevitable and the estimation factors that I use assume the worst case scenario. The environmental impacts of mining are irreversible. To evaluate the cost of avoiding these damages, I evaluated the cost to apply existing control technologies. These potential technologies are drawn from other mining industries or other countries.

Some environmental control cost estimates are high, some are low, and some are suitable. As discussed in Chapter 4, control costs to mitigate subsidence and surface mine pits are appropriate. Acid mine drainage and methane mitigation cost estimates are high, while erosion control and robotic mining costs are low. I evaluated two regulatory scenarios that could remedy environmental impacts: (1) applying the Surface Mine Control and Reclamation Act (SMCRA) stringently and mandating damage prevention in addition to reclamation, (2) application of the Clean Air Act, in addition to more stringent SMCRA and Clean Water Act (CWA) enforcement. By examining these two hypothetical regulatory scenarios, I show how U.S. coal exploitation and mining costs are affected by environmental policies and the need to develop cost effective control technologies. In the first scenario, the cheapest greenfield coal mines during the first thirty years of mining under more rigorous permitting and enforcement will be surface mines in the Colorado Plateau and Rocky Mountains and Great Plains, just as they are under laissez faire regulation. However, in the following years mining cost could increase two to six-fold. In the second scenario, mining costs increase immediately. They are twice the cost of mining under laissez faire regulation for the first 10 years, then could be double to ten times the cost of business as usual mining.

To resolve the uncertainty of coal availability, supply cost, and environmental impact, we must devote research capital to mining technologies. There is no central coal mining research organization in the U.S. government. Coal resource analysis and mining research is stagnant, or developments are held confidential. When I contacted mining companies and equipment manufacturers to inquire about technology innovation and environmental control, the response ranged from indignation that there would be a need for new technologies to secretive allusions to significant advancements in the state of the art. When I contacted the Office of Surface Mining (OSM) and Environmental Protection Agency (EPA) to inquire about environmental control, most responses confidently stated that no environmental problems would arise from mining because regulation will mandate mined land restoration to acceptable conditions. I was unable to obtain information about mining innovation and environmental control technologies from U.S. sources, so had to travel to Australia to learn about these advances from their CSIRO and mining research universities. There is a need for U.S. based coal research. Unlike the U.S. they have a coal research organization, the Australian Coal Association Research Program (ACARP), which coordinates research throughout the government, private industry, and universities. The ACARP provides a transparent platform to coordinate research and report findings. Among the notable technologies developed and demonstrated by Australian researchers are robotic mining technologies, underground mine roof control technologies to reduce subsidence and enhance safety, and measurement of fugitive greenhouse gas emissions from underground and surface mining. The U.S. should focus more attention and resources on coal research if we are to remain dependent on it as a major energy source and extract it in an environmentally responsible manner. The U.S. approach could be developed to resemble the Australian model.

Just as regulatory responsibilities are dispersed among several agencies, so are research responsibilities divided among the OSM, EPA, DOE, and USGS. As discussed in Chapter

3, DOE leads mine technology research while USGS evaluates resource availability. With respect to the environmental concerns discussed in Chapter 4, EPA regulates mining's impact on air and water resources, and OSM regulates mine-specific impacts such as land use and topography changes, and acid mine drainage. While all of these agencies should have an interest in contributing to the development of technologies and strategies that can improve resource recovery and dramatically reduce the environmental externalities of coal extraction, their collective performance over recent decades suggests strongly that simply giving some or all of them an expanded research budget, is unlikely to produce the kind of serious coordinated research, development and demonstration program that the nation needs.

Existing government research programs must grow and collaborate to maximize innovation and minimize redundant work. A summary of the recommended actions and costs is in Table 34. As shown in Table 34, 2005 budget allocations for mining systems, resource assessment and environmental research are scant. They must receive more funding, but this money must be allocated wisely. The government's responsibility is to manage research, encourage experimentation and transformational research, facilitate collaboration, and ensure that research goals are met. It must define these goals and projects carefully.

Assuming that fundamental research regarding coal geology and surrounding environmental conditions (see Chapter 3 and 4) would require focused effort from geologists and environmental scientists working full time on the analyses, the 2005 budget would only allow for a handful of projects to be undertaken each year in one or two coal regions. There would be little budget left for technology innovation and deployment. A demonstration project of prototypical technology would need multiple week-long tests, which could incur a cost of \$0.5 - \$1 million. If we seek to demonstrate a variety of technologies, such as those described in Chapter 4, we will have to increase research expenditure and efforts.

Table 34 Programs that should be expanded to reduce uncertainty associated with coal resource development

Government Agency	*Program*	*Description*	*2005 Budget (million \$/year)[a]*	*Proposed Budget Increase (million \$/year)*
Department of Energy	Mining Industry of the Future	Public-private partnership that pursues mine equipment and system innovation to improve resource recovery	1	29
United States Geological Survey	NCRA	Public-private partnership between industry, academia, and Federal and State geological surveys that expands the NCRA to include all coal regions and available coal data, reports data uniformly and updates it as necessary	10	20
Office of Surface Mining	General research	Public-private partnership that emphasizes coordination between the Office of Surface Mining and Environmental Protection Agency, to improve understanding of mining's relationship with the environment and develop mitigating technologies	10	50-60

[a][1]

All EIA energy forecasts project that coal demand increases over time. We must ascertain available coal resources, and understand how we can reduce the environmental impact of mining. This thesis shows that resource uncertainty, mining cost, and irreversible environmental impact will increase with coal demand. However, it also finds that it is possible to reduce the uncertainty associated with coal resource availability and avoid environmental impacts from mining. Given U.S. dependence on coal for electricity, we will be better positioned for long-term management of our coal and natural resources if we prioritize understanding coal resource availability, extraction and mining environmental control technologies.

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Appendix A Notes on Chapter 2

A.1 Mine system simulation

A.1.1 Surface mining system simulation

Surface mining is a series of material breaking and moving processes. The model simulates a hydraulic shovel and truck operation. First land is cleared and prepared for mining. Next, holes are drilled into the overburden, and explosives dropped into the holes to break up the overburden. The crumbled overburden is then excavated to expose the coal. The coal is broken up by hydraulic excavators and removed by truck. The overburden from the pits, commonly referred to as spoil, is placed in previously mined pits. Excess spoil is placed into surface storage or impoundments. The amount of material – overburden or coal – is dependent on pit size.

The model includes overburden removal steps in the surface mine simulation. After overburden is drilled, broken up with ammonium nitrate fuel oil (ANFO), and removed by shovel and truck, the coal is mined by excavator and truck. The model assumes 1 – 7 surface mining teams[6] comprised of 1 – 2 excavating shovels or bulldozers, 2 – 5 trucks varying from 125 – 240 tons, a grader and drill. Drilling, blasting, shovel time, and road length algorithms are based on the industry standard and rules of thumb [1]. The model is capable of modeling up to 10 coal seams and interburden. The text below describes operations within a single coal seam, but if a mine is to access several seams this method is applied to each seam in order to determine the total production rate.

A.1.1.1 Surface pit sizing, estimating coal and overburden volume

Surface mine pit sizing is based on the dimensions of the excavation equipment. In order to size a pit, the width and length must be ascertained. It is assumed that, at minimum, the pit must fit the base of a hydraulic excavator. The maximum pit width is assumed to

[6] It is understood that typical mining jargon refers to operational crews assigned to a mining process, or a daytime or nighttime shift. The term “team” in this case refers to all crews and equipment available to break and move coal or overburden material at the mine. Support equipment that maintains site operations, such as water trucks at a surface mine, are not included in the “team.”

be 150 ft [1].A range of cutting radii, crawler widths, cleaning radii and excavator capacities were collected from manufacturer literature, and thus assumed to be 16 – 25 ft, 16 – 24 ft, 21 – 32 ft and 19 – 56 yd^3, respectively [2-6]. The pit width range is assumed to be a uniform distribution between the minimum and maximum pit widths, and is determined according to equations (1 – 2).

$$PW_{\min} = \min(r_{cleaning}, r_{cutting}) + \frac{CW}{2} \tag{1}$$

$$PW = Uniform(PW_{\min}, 45.72) \tag{2}$$

Where:
PW_{min} = minimum pit width
$r_{cleaning}$ = hydraulic excavator cleaning radius
$r_{cutting}$ = hydraulic excavator cutting radius
CW = crawler width
PW = pit width

The pit length is estimated in a similar fashion to pit length. It is assumed that the minimum pit length must accommodate the maximum size hydraulic excavator, and that the maximum pit length is equal to the length of the coal resource:

$$PL_{\min} = \max(r_{cleaning}, r_{cutting}) + \frac{CW}{2} \tag{3}$$

$$PL = Uniform(PL_{\min}, L) \tag{4}$$

Where:
PL_{min} = minimum pit length
PL = pit length
L = length of coal resource

Pit area is estimated as the product of pit length and width. The volumes of overburden overlying the pit, and the coal contained in the pit are determined according to the user input overburden depth and seam thickness.

Coal is not completely extracted during surface coal mining. Excavator shovels are not fine tuned machines, and cannot precisely cut overburden and coal separately. A small amount coal is often cut with the last layer of overburden and lost in the spoil pile.

Frequently, a thin layer of coal is left in the pit before it is filled. It is too expensive to separate this thin layer of coal from the underlying material that would be extracted if the shovel were to dig it out, so it is left behind. To account for the lost coal, it is assumed that a total 10% of coal is lost in this manner, per pit [7]. The coal left in the pit is commonly referred to as "pit losses." The amount of coal mined is equal to the original amount available in the pit, less this lost coal.

A.1.1.2 Estimating ANFO needs

The overburden is broken up by ANFO. The drill hole spacing, powder factor, and the ANFO quantity used is calculated by following the methods in the standard literature [1]. The ANFO needed is based on the expected lifetime of the mine, and area to be cleared. Although not all overburden rock in U.S. coalfields needs to be blasted, the model evaluates the average overburden density for the entire nation, and assumes that explosives will remove it. As a result of this assumption, explosive estimates and charge weights may seem high or low, if a specific region is considered. 50th percentile charge weight is 1,053 lbs according to methods in the literature [1], and assuming a industry standard drill length of 25 – 65 feet [8] and ANFO standard gravity of 0.75 – 0.95. The resulting powder factor estimate is 0.2 lb/yd^3 with 5th and 95th percentiles of 0.04 lb/yd^3 and 0.8 lb/yd^3, respectively. The estimated amount of ANFO to clear the mining area is calculated as per Equation (5):

$$ANFO = OB_V \times PF \tag{5}$$

Where:
ANFO = weight of ANFO required
OB_V = volume of overburden overlying coal resource to be mined
PF = powder factor

A.1.1.3 Overburden and coal cutting and loading time

The time needed to remove overburden and coal is the total drilling time, ANFO placement, wiring and detonation time, safety clearances pre and post-detonation, and overburden and coal excavating time. The time needed to haul the coal out of the pit is discussed below. The volumetric drill rate to insert ANFO into overburden is 750 –

3,800 ft^3/minute [8], and borehole detonation timing is 11 – 17 ms/ft [1]. The ANFO insertion and explosion time is calculated based on the number of boreholes previously calculated.

Using the previously mentioned overburden and coal swell factors, the volume of broken material is calculated. The rate to load the material into trucks to be removed from the pit is determined according to shovel rates and capacity. Shovel cycle time and capacity are estimated according to ranges provided in the general literature. The shovel cycle time is assumed to be 20 – 44 s, and is divided by a correction factor of 1 – 1.25 in the case that mining is undertaken in less than optimum conditions [1]. The excavator capacity is assumed to be 19 – 56 yd^3 [8], with a 0.54 – 0.83 capacity factor [1].

A.1.1.4 Surface mine road design and travel time estimation

Assuming a varying truck size of 125 – 240 tons, the number of truckloads needed to remove waste material and coal from the pit is determined. It is assumed that each truckload requires a single round trip to deliver the coal or waste material to an onsite collection area. Road distances in and out of pits are estimated so that hauling times can be calculated. It is necessary to know hauling time because the production rate is dependent upon the travel time for trucks in and out of the pit. In order to organize the pits for road designs, the model groups them into "pit regions" that are 1.5 mile by 3.75 mile, based on analysis of typical surface coal mine layout to be mined over a period of 20 years [9]. Although the model considers mine lifetimes that range between 10 and 30 years, assuming a typical surface coal mine layout designed for a 20 year lifetime is a best approximation at this time. Shorter mine lifetimes are typical in Appalachia or regions where high quality coal improve the financial feasibility of mining a small reserve.

To estimate the road distance in and out of a pit, it is assumed that roads will be designed with a maximum 8 percent grade, for greatest safety [1]. Using the pit width and length, the distance for a zig-zag or spiral road can be determined. The model chooses the shortest path. Assuming again, maximum safety, the truck traveling speed in and out of the pit is assumed to be 15 – 30 mph [1]. Truck dumping time is assumed to be 50 s [10].

It is assumed that travel time and dumping time is the same for waste materials, or overburden, and coal.

A.1.1.5 Estimating surface min production rate

As described above, the model calculates the total production time needed to mine the pit by breaking up overburden with ANFO, and extracting the overburden and coal. Knowing the original amount of coal available in the resource, and the number of model defined pits that can be accommodated, the production rate (coal/year) is estimated by dividing it by the production time for the 1 – 7 surface mining teams used to extract coal.

A.1.2 Continuous mine system simulation

Continuous mining uses several unit operations to cut, load, and remove coal from an underground mine. This method is also called room and pillar mining because rooms of coal are extracted while pillars are left to support the overburden, or roof. It consists of cutting the coal with a continuous miner, loading the coal and securing the roof. While the continuous miner cuts the coal, it intermittently loads the coal onto shuttle cars. The shuttle car then trams the coal to a central pick up point for transport to the surface. The coal is transferred from the collection point to the surface by conveyor belt. After the continuous miner has cut the coal, it backs out of the cut room. The roof bolter then enters and secures the roof with bolts in the overlying strata. All the while, electricity, water, and ventilation systems must be steadily expanded and maintained in order to support the mine and miner's operations underground.

The model assumes that there is a uniform distribution of 2-4 continuous mining teams. Each team is comprised of a continuous miner, 2-3 shuttle cars and 1-2 single boom roof bolters.

A.1.2.1 Room and pillar sizing

The model assumes that a continuous mine has at least three entries. The pillar width is determined as a function of overburden depth, such that the amount of coal contained in the pillars increases with depth. Equations (6 – 8) are developed from direct observations of underground mine pillar widths in West Virginia at 6 – 8 ft [11]:

$$W_{2.4} = 0.36 \times (OB_D)^{0.7} \quad (6)$$
$$W_{2.1} = 0.38 \times (OB_D)^{0.5} \quad (7)$$
$$W_{1.8} = 0.406 \times (OB_D)^{0.8} \quad (8)$$

Where:
$W_{2.4}$ = pillar width for a seam with maximum thickness of 2.4 m
OB_D = overburden depth
$W_{2.1}$ = pillar width for a seam with maximum thickness of 2.1 m
$W_{1.8}$ = pillar width for a seam with maximum thickness of 1.8 m

It is assumed that these pillars are square, such that the length is equal to the width, and height equal to seam thickness. For continuous mines in a large coal resource, it is assumed that entry length is never more than 10,000 – 13,000 feet, which is the longest achievable length of a longwall panel [12]. It is assumed that continuous mine workings will not exceed this length because if it is not economical for longwall mining, a higher yield method, to sustain lengthier working areas then it certainly will not be affordable for a continuous mine. If the length of the coal resource is less than 10,000 feet, then the entry length of the mine is equal to the length of the resource. Based on these assumptions of mine length, pillar widths, and assuming entry width of 20 feet for minimum safety requirements, the number of rooms and pillars within the resource is estimated. The starting amount of coal for a continuous mine is estimated based on the maximum entry length, coal resource width, and seam thickness. The coal mined is estimated to be the original amount of coal in a continuous mine section less the amount of coal left in the pillars.

A.1.2.2 Continuous mine coal cutting, loading, and tramming time

After the amount of coal produced by the mine is estimated, the number of cuts and loads to extract the coal can be determined. It is assumed that the continuous miner has a cutting depth of 20 – 30 feet and cutting width of 20 feet based on published machine sizes [8]. The amount of coal that is broken per continuous miner cut is determined:

$$T_{CM} = CM_D \times Th \times CM_W \times \rho_B \quad (9)$$

Where:
T_{CM} = tons of coal cut by the continuous miner
CM_D = continuous miner cutting depth

Th = seam thickness
CM_W = continuous miner cutting width
ρ_B = bituminous coal density

Assuming a shuttle car hauling capacity that ranges from 8.5 – 17 yd^3, on average 11 shuttle car loads are needed to haul the cut coal. Those who are familiar with continuous mining may note that roof bolting has not been mentioned yet. The amount of roof bolting time needed is negligible [13], and the model's continuous mine system timing sequence accounts only for the continuous miner and shuttle cars.

Shuttle car timing is variable and is derived from published shuttle car length 30 feet [8], and timing studies data. The timing studies examined include methods to estimate total cut cycle time, coal hauling distance, which define tramming distance, based on recorded underground vehicle speed, loading rate, time to switch the continuous miner in and out of the mined room with the shuttle car, waiting delays, dump time, and in room cutting delays [14].

A.1.2.3 Estimating continuous mine production rate

Production rate is estimated by dividing the amount of coal mined by the total production time, for a total of 2-4 mining teams. As described above, the amount of coal produced is the starting amount of coal in the mine less the coal in the pillars. The total production time is the time needed to load, changeout the continuous miner and shuttle car, wait on a car if necessary, as well as delays for advance activities. Advance activities include installing ventilation, water and electrical systems to support miners and equipment.

A.1.3 Longwall mines system simulation

The model simulates a longwall mine with a minum of one longwall panel and two continuous mining development sections and barrier pillars. It is assumed that 1 – 2 longwalls operate in a longwall mine. Altogether, the equipment configuration per longwall within the mine is assumed to be a longwall, 2 – 3 continuous mining teams as described above, a face conveyor and stage loader, longwall shields, a belt conveyor, and 4 – 6 shuttle cars (in addition to the shuttle cars devoted to the continuous mining teams in the development sections.)

The sequence of mining in a longwall mine begins with development sections mined by the continuous mining method. A diagram of how a longwall mine is laid out is shown in Figure 2. The ventilation air flows from the main entries to the bleeder entries, which eliminates methane build up in the broken material known as "gob" that forms as the longwall panel is mined. Two parallel development sections must be completed in order to support a longwall. It is assumed that when the longwall panel begins operation, additional development sections may begin in order to support future longwall panels. These development sections are mined in the same manner as a continuous mine, except that the pillars, referred to as "chain pillars", have a constant width and length of 82' and 160', respectively, at any depth [11]. The coal extracted in the development sections is transported within the mine by shuttle cars, as it is in the previously described continuous mine system. Coal mined by the longwall shearer is collected and moved by the face conveyor and stage loader to a belt conveyor. It is assumed that the longwall cutting, loading, and transporting system is fully automated.

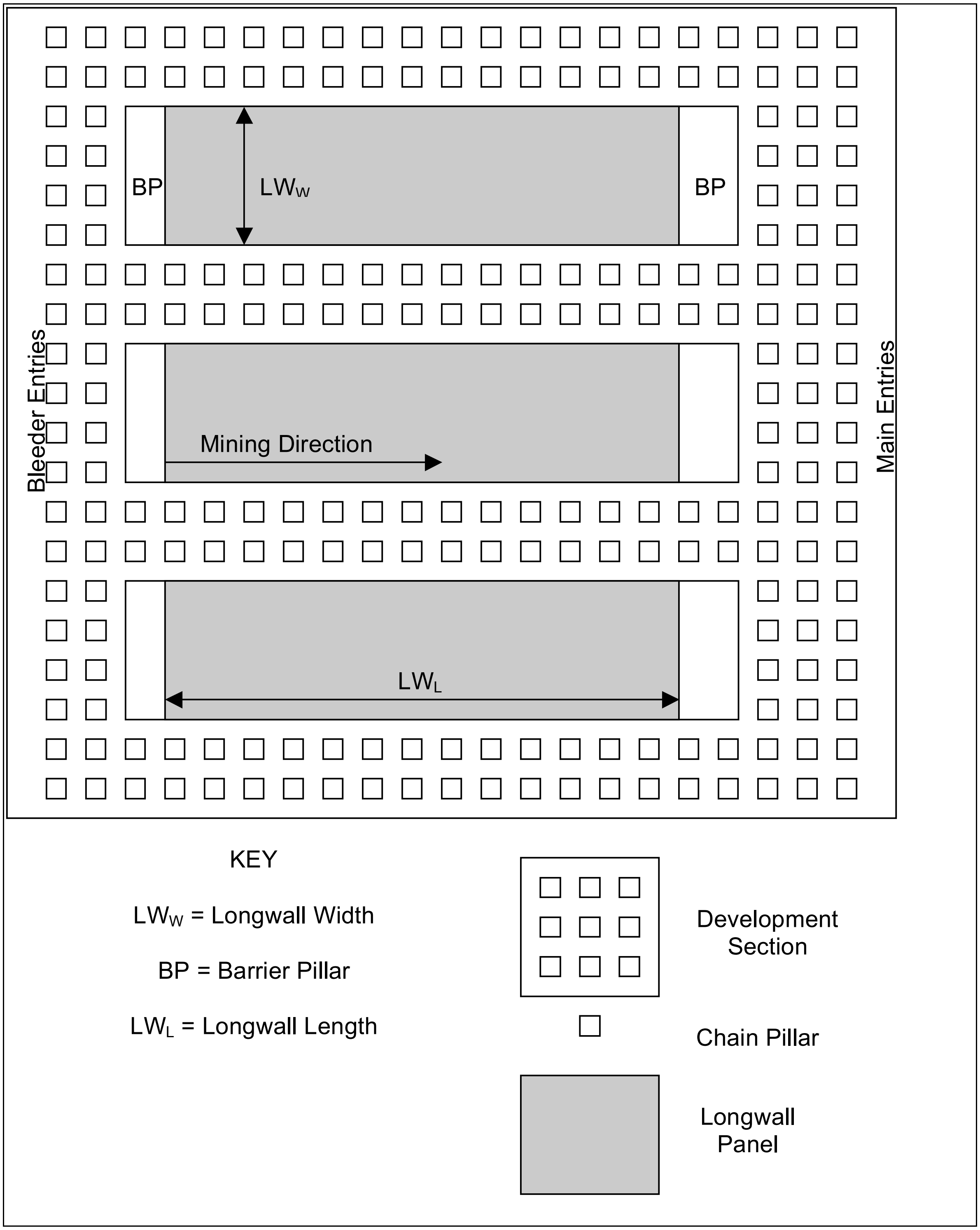

Figure 29. Longwall Mine Plan View

A.1.3.1 Longwall sizing

The average longwall underground longwall panel dimensions are based on the current size reported by industry. The average face width is 939.2 feet [15] and entry width is

100 – 350 feet and barrier pillar width of 200 – 500 feet [1]. The maximum panel length is assumed to be that which is the maximum technically possible, 10,000 – 13,000 feet [12]. Development sections are assumed to have a maximum of 3 entries, with pillar widths determined in the same manner as for the simulated continuous mine system described above.

The number of panels that will fit within a coal resource are determined by the combined width of the development sections and panels. The width of the coal resource is divided by the estimated width of a panel with two development sections in order to ascertain how many panels can be mined within the resource. If the resource is not large enough to support a single panel with two development sections, then it is assumed that longwall mining cannot be pursued and will not be simulated.

A.1.3.2 Timing of longwall panels and development

Continuous mining is used in the development of the longwall. The model assumes the same operating conditions for continuous mining teams used in longwall development as in a standalone continuous mine. To simulate a longwall mine, the model coordinates the timing of longwall panel mining to start when the two necessary development sections are completed. After the number of panels and development sections is determined, the time it will take to mine the sections and panels is determined.

A.1.3.3 Longwall shearer cutting and conveyor loading

The model assumes that the longwall shearer makes each pass at the rate of 35 – 82 feet/minute [1] with a cutting depth of 35 – 41 inches [15]. With each pass, the shearer cuts and returns through the coal. Each pass cuts the coal and it is loaded to the conveyor belt. The volume of coal cut per each shearer pass is determined, and the shearer advance rate is used to estimate the theoretical shearer production rate:

$$T_{LW} = LW_D \times Th \times LW_W \times \rho_B \tag{10}$$

$$LW_P = \frac{T_{LW} \times LW_{AR}}{LW_W}$$

Where:
T_{LW} = tons of coal cut by longwall shearer
LW_D = longwall shearer cutting depth
LW_W = longwall face width
LW_P = longwall shearer production rate
LW_{AR} = longwall shearer advance rate

To determine the total amount of time it takes to mine a longwall panel, delays to straighten the longwall are added. It is assumed that the shearer takes 10 – 20 passes before it needs to be straightened, and that 30 – 90 minutes are needed to set it straight. Longwall move time between panels is assumed to take up to 4 weeks. Furthermore, data on coal conveyor losses is used; it is assumed that 8 – 12.9 tons/hour are spilled [16]. The production is adjusted to reflect these time delays and coal losses.

A.1.3.4 Estimating production rate for longwall mine

Total longwall production is comprised of the longwall panel and development section outputs, for the 1 – 2 longwalls assumed to be operating in the simulated longwall mine with associated continuous mining production. As mentioned above the development section production rate is determined in a similar fashion to the continuous mine simulation, accounting for possible delays in machine travel within narrower working areas. The estimated development section and longwall shearer production are added together to obtain the total production estimate for the longwall mine.

A.1.5 Preparation plant simulation

Designing and simulating an onsite coal preparation plant was beyond the scope of this work. Instead, it is assumed that the majority of plants are Level IV plants. In 1996, a third of North American coal cleaning plants were Level IV [17] and it is assumed that this type of plant remains predominant today.

A Level IV plant has a 60 – 80% range of recovery, and consists of coarse and fine coal cleaning with froth flotation [17] from the run of mine production. The run of mine production rate is assumed to be coal plus partings. The amount of partings produced in addition to coal is estimated:

$$WR = \rho_B Area(M_{height} - Th) \qquad (11)$$

Where:
WR = tonnes of waste rock mined over the entire mine lifetime
Area = area mined over mine lifetime
M_{height} = height of continuous miner or longwall shearer

It is assumed that partings within the coal seam itself are minimal. Based on this assumption, no waste rock is mixed with the run of mine output for a surface mine. For an underground mine, waste rock consists of the amount of overburden that the cutting machine – continuous miner or shearer – cuts from the roof in addition to cutting coal.

A.1.6 Project, or financial, life estimation

Based on the model simulation of production rate, the model assigns a financial lifetime to the mine project. The lifetime of the resource is estimated by dividing the total amount of coal in the resource by the production rate. A minimum financial lifetime of 10 years and a maximum of 30 years are assumed. If resource lifetime is less than 10 years, it is assumed that the financial lifetime of the project is 10 years. Similarly, if the resource lifetime is greater than 30 years, then 30 years of production and operation is assumed. For resource lifetimes between 10 and 30 years, the calculated lifetime is used.

A.2 Mine cost simulation

The model estimates costs corresponding to unit operations and steps in the production simulation for continuous, longwall, and surface mines. Costs are incurred before, during, and after mining. The four main process categories are premining, groundbreaking and preparation, operating and closure. Some costs are estimated following rules of thumb, such as pre-mine ground clearing. Other costs are estimated by interviewing industry experts, such as royalty and bonding costs. However, the majority of cost data used in the model is from the general literature [8, 18]. The engine sizing of the equipment is used to estimate the amount of fuel consumed to operate the equipment. Based on assumptions about the depreciation lifetime of equipment, it schedules equipment replacement. Costs for auxiliary operations, such as clearing surface land, digging shafts, installing and operating hoists and ventilation, are also estimated. Taxes on the sales of coal, purchase of capital, as well as those required by health, safety, and environmental regulations are estimated. These costs are all calculated according to the project lifetime that the model assigned to the mine. For all financial calculations, the model assumes an interest rate of 8-15 percent, and the financial lifetime estimated by the model as described above.

A.2.1 Site development, Equipment capital costs and depreciation

The capital costs of almost all mining equipment considered by the model were taken from the Western Mine Engineering Inc., Handbook. Table A1 shows the capital costs and equipment lifetime input into the model. In addition to mining equipment, the surface support facilities such as shop and warehouse, changing facilities and offices, and haulage roads, are included in the capital cost and depreciation assessment as these must all be purchased or built to support the mine.

Table A35. Equipment Lifetime and Capital Cost[a]

Equipment Name	Life (Years)	Equipment Cost (Thousand 2005$)
Longwall shearer (46 – 177 inches)	5	1,700 – 2,500
Longwall shields	10	118 – 155
Face Conveyor and Stage Loader	5	1,709 – 3,197
Power Center and Hydraulic System	10	3,540
Continuous Miner	5	2,162 – 1,081
Shuttle Car	5	460 – 720
Roof Bolter	5	385 – 722
Rock Duster	7	25 – 30
Spare Shuttle Car	7	460 – 720
Conveyor Feeders/Breakers	5	275 – 315
Belt system (48 – 60 inches)	7	1,600 – 2,400
Power center (1500 kVa)	7	85.5
Power center (5000 kVa)	7	176
Shop/Warehouse facilities	30	243
Change facilities/mine offices	30	191
Access/Haulage road	30	280
Site/Surface building	7	93.9
Underground compressors and lines	30	130
Water/Sewage treatment facilities	30	67.1
Surface power substation and transmission lines	30	420
Mine dewatering system	30	101
Grader	7	2,060 – 2,420
240 ton truck	7	1,180 – 1,690
125 – 150 ton truck	7	8,810 – 2,700
Excavator shovel	5 – 7	3,613 – 8,810
Track dozer	5	50 – 400
Water truck	5	20 – 50
Rubber-tired dozer	5	18 – 30
Blasthole drill	5	633 – 777
Truck mounted coal drill	7	550 – 600
Fuel and lubricating oil truck	7	26 – 78
Longwall shield retriever	10	285 – 510
Personnel carrier	10	190
Self rescuer respirator	30	0.38
Shaft cutting machine	30	300 – 1,000

[a]Source: [8, 18].

Cost data for ventilation, hoists, and preparation plants were not readily available, because they are dependent upon mine size or production. The size and cost of these mine components were estimated by following general rules of thumb, found in the literature as will be described further in this section.

The model only considers ventilation systems and costs for underground mines. To estimate the cost to ventilate underground mines, the number of shafts and fans were determined. First, to estimate the number of shafts needed, it is assumed that the distance between shafts for an underground mine must be between 150 – 400 feet [19]. The number of shafts that can fit into the mine area are calculated, and assuming that the costs of inserting a shaft range from \$82/ton - \$1640/ton of rock excavated from the shaft [20], the total cost of ventilation shaft sinking is determined. Second, the model sizes a ventilation system according to underground mine type. The method used by the model to size the ventilation system is adapted from those found in the literature, which bases the estimate on mine production rate [21]:

$$Q = 0.23(P_i)^{0.8} \tag{12}$$

$$f = \frac{ab \times OB_D}{1 + b \times OB_D} \tag{13}$$

$$Q_{adj} = fQ \tag{14}$$

Where:
Q = air flow rate needed for mine, m^3/s
f = correction factor
a, b = correction factor coefficients
Q_{adj} = corrected air flow rate, m^3/s

The air flowrate (Eq. 12) is determined according to the production rate expected per mine type. However, mine production rate is not the only factor affecting ventilations requirements. Specific regional conditions also influence the amount of air needed in underground mining. Regional correction factors (Eq. 13) are used to determine a factor that can be used to estimate the actual air flow rate needed (Eq. 13). The model assumes average regional correction factors of a = 1.76 and b = 0.00075 [21].

Having determined the necessary ventilation air flow rate, the model chooses fan sizes accordingly, and it is assumed that the fan will last the lifetime of the mine. Capital costs for fans, and sizes are shown in Table A2.

Table A36. Underground ventilation fan and motor sizing and cost[a]

Air flow rate, m^3/s (tcf/min)	Fan Motor Size, W (hp)	Axial Fan Diameter, m (inches)	Fan Motor Capital Cost (1000 \$)	Fan Capital Cost (1000 \$)
≤ 47.2 (100)	40.6 – 223.1 (40 – 220)	1.54 (60)	20 – 70	81.6 – 101.6
≤ 94.4 (200)	243.3 – 567.8 (240 – 560)	2.13 (84)	40 – 116	40 – 180
≤ 141.6 (300)	365 – 851.6 (360 – 840)	2.43 (96)	53 – 134	134 – 164
≤ 188.8 (400)	486.7 – 1135.5 (480 – 1120)	2.54 – 2.94 (100 – 116)	70 – 182	195 – 225
≤ 236.0 (500)	608.3 – 1419.4 (600 – 1400)	3.05 (120)	78 – 220	195 – 225
≤ 283.2 (600)	730.0 – 1703.3 (720 – 1680)	3.05 (120)	90 – 250	200 – 246
≤ 19822 (700)	1135.5 – 1419.4 (1120 – 1400)	3 – 3.35 (120 – 132)	224 – 255	244.7 – 254.1
> 19822 (700)	1703.3 (1600)	3.66 (144)	224 – 255	244.7 – 265.1

[a]Source: [8].

It is assumed that 2 – 4 hoists are needed per mine [22, 23]. Individual hoist costs are dependent on the distance that they must move coal, supplies, and workers between the surface and mine workings. Hoist costs are evaluated for hoists of 1,000 – 3,000 feet. Capital and installation costs and the power rating of these hoists are shown in Table A3. The length of the hoist is determined according to the overburden depth overlying the seam.

Table A37. Hoist capital and installation costs, and motor size[a]

Depth, m (feet)	Cost (1000 \$)	Engine power rating, W (hp)
305 (1,000)	800 – 3,800	253 – 3042 (250 – 3,000)
610 (2,000)	1,800 – 7,200	406 – 6083 (400 – 6,000)
1515 (3,000)	1,900 – 7,300	608 – 8111 (600 – 8,000)

[a]Source: [8].

As explained in a previous section, it is assumed that the on site preparation plant is a Level IV plant. The size and cost of this plant is, like the ventilation system, dependent on mine production rate. The capital cost of the plant was assumed according to the basic rule of thumb based on run of mine output [17]:

$$C = xROM \tag{15}$$

Where:
C = prep plant capacity
x = cost multiplier
ROM = tonnes/s run of mine output

It is assumed that the cost multiplier is uniformly distributed between 3.8 and 15.2.

Having determined the capital cost of all equipment, the model assumes straight line depreciation to estimate depreciation costs over the mine's life. Throughout the mine's life, new capital expenses are incurred as equipment is replaced at the end of its life. The number of equipment per type of mine is shown in Table A4.

Table A38 Quantity of Equipment Assumed per Mine[a]

Equipment Name	Longwall Mine	Continuous Mine	Surface Mine
Longwall shearer (46 – 177 inches)	1 – 2	0	0
Longwall shields	156 – 220	0	0
Face Conveyor and Stage Loader	1 – 2	0	0
Power Center and Hydraulic System	1 – 2	0	0
Continuous Miner	4 – 6	3 – 5	0
Shuttle Car	6 – 12	9 – 15	0
Roof Bolter	4 – 6	4	0
Rock Duster	3 – 6	3 – 6	0
Spare Shuttle Car	4 – 8	4 – 8	0
Conveyor Feeders/Breakers	4 – 6	3 – 5	0
Belt system (48 – 60 inches)	8-22	4-20	0
Power center (1500 kVa)	1 – 2	1 – 2	0
Power center (5000 kVa)	1 – 2	1 – 2	0
Shop/Warehouse facilities	1	1	1
Change facilities/mine offices	1	1	1
Access/Haulage road	1	1	3 – 10
Site/Surface building	1	1	1
Underground compressors and lines	1	1	0
Water/Sewage treatment facilities	1	1	1
Surface power substation and transmission lines	1	1	1
Mine dewatering system	1	1	1
Grader	0	0	2
240 ton truck	0	0	2 – 14
125 – 150 ton truck	0	0	2 – 14
Excavator shovel	0	0	1 – 7
Track dozer	0	0	3 – 5
Water truck	0	0	1 – 2
Front end loader	0	0	2
Blasthole drill	0	0	1 – 7
Truck mounted coal drill	0	0	1
Fuel and lubricating oil truck	0	0	2
Longwall shield retriever	1	0	0
Personnel carrier	5	5	0
Self rescuer respirator	10	10	0
Shaft cutting machine	1	1	0
Ventilation system	1	1	0
Preparation plant	1	1	1

[a]Sources: [22, 23].

A.2.2 Cost of consumables

The model estimates the amount of electricity, diesel and lubricating oil are needed to run the equipment. It also estimates the amount of ANFO needed to clear overburden from the coal resource for surface mining operations. Water, though used throughout the mining process, is not included in the model. The amount of fuel needed is estimated, based on the engine size of equipment. The model estimates these costs, instead of using the published data in the Western Mine Engineering Inc., Handbook, because it allows for greater flexibility in adjusting for real commodity costs. That is, users can change the electricity, diesel and lubricating oil costs in the model in order to estimate the cost to operate mining equipment.

To estimate energy needs, the model determines the amount of electricity, diesel, and lubricating fuel based on the equipment's operating time, an experience based factor per consumable category, and assumptions of consumable price. 2005 prices for electricity and diesel are assumed to be 0.056 – 0.064 $/kWh, 2.52/gallon, respectively [24]. The current cost of lubricating oil could not be found, and it is assumed that a large operation like a mine would buy lubricating oil in bulk at a price that is prenegotiated with a seller. Therefore, the lubricating oil cost is estimated, based on a regression equation calculated from reported Western Mine Engineering Inc., Handbook lubricating cost data. This equation estimates lubricating oil costs as a function of engine size and capital cost:

$$L = 0.07613805 + 0.00022 \times PR + 5.602 \times 10^{-6} C_{cap} \tag{16}$$

Where:
L = lubricating oil price, \$/gallon
PR = equipment power rating
C_{cap} = equipment capital cost

Power ratings of equipment that requires lubricating oil are shown in Table A5. These power ratings are also to estimate the amount of electricity and diesel fuel consumed; the third and fourth columns indicate whether the equipment is electric or diesel powered.

Table A39. Power Rating of Mining Equipment[a]

Equipment Name	Power Rating, (hp)	Electric	Diesel
Longwall shearer (46 – 177 inches)	247 – 433	X	
Face Conveyor and Stage Loader	600 – 1800	X	
Continuous Miner	300 – 900	X	
Shuttle Car	40 – 80	X	
Roof Bolter	40 – 140	X	
Rock Duster	10	X	
Spare Shuttle Car	40 – 80	X	
Conveyor Feeders/Breakers	150 – 180	X	
Belt system (48 – 60 inches)	550 – 800	X	
Grader	140 – 500		X
240 ton truck	1790 – 2166		X
125 – 150 ton truck	1050 – 1200		X
Excavator shovel	3000 – 3350		X
Track dozer	70 – 120		X
Rubber-tired dozer	25 – 75		X
Blasthole drill	475 – 525		X
Truck mounted coal drill	525 – 700		X
Longwall shield retriever	100 – 150	X	
Personnel carrier	80	X	
Shaft cutting machine	100 – 400	X	
Ventilation	Varies, refer to Table 2	X	
Hoists	Varies, refer to Table 3	X	

[a]Source: [8]

Equipment operation hours are shown in Table 6. Continuous operation is assumed for power and safety equipment, such as the power centers, longwall shields, and ventilation. All other equipment is assumed to have 8 – 12 hours of down time during the day for maintenance. Equipment that is not continuously needed to extract coal, such as the grader, and blasthole drill, are operated as needed. Their operational hours are defined accordingly.

Table 40. Daily operating hours for mining equipment

Equipment Name	Operation (Hours/Day)
Longwall shearer (46 – 177 inches)	10 – 16
Longwall shields	24
Face Conveyor and Stage Loader	10 – 16
Power Center and Hydraulic System	24
Continuous Miner	10 – 16
Shuttle Car	10 – 16

Roof Bolter	10 – 16
Rock Duster	10 – 16
Spare Shuttle Car	10 – 16
Power center (1500 kVa)	24
Power center (5000 kVa)	24
Grader	2 – 4
240 ton truck	10 – 16
125 – 150 ton truck	10 – 16
Excavator shovel	10 – 16
Track dozer	2 – 20
Water truck	2 – 20
Rubber-tired dozer	2 – 20
Blasthole drill	1 – 5

As previously mentioned, ventilation, hoist, and preparation plant costs were not assembled from Western Mine Engineering Inc., Handbook information. Preparation plant operating costs are estimated by following rule of thumb, assuming that the operating cost per run-of-mine ton ranges from 0.50 – 4.00 \$/ton [17]. Ventilation and hoist operation costs are calculated separately.

The model calculates ANFO expense as the cost to supply necessary ANFO to clear overburden for surface mining. ANFO price is assumed to be 0.10 – 0.18 \$/lb [1].

A.2.3 Expected value of labor cost

It is assumed that the average mine will employ the proportion of employees per category as reported to the U.S. Bureau of Labor Statistics, and pay them according to the published average salary and benefits rates. The 2005 U.S. employer expenditures on employee benefits were \$7.87/hour, which covered social security, Medicare, unemployment insurance, worker's compensation, paid leave, retirement and savings benefits and life, health and disability insurance. The total employee benefit cost is calculated according the mine's total annual operating hours. The expected value of total employee wages is also calculated. The expected value of employee wages is calculated according to expected employment per type of mine. It is expected that all mines employ the same proportion of employees, except that surface mines will not employ underground mining specialists such as continuous miner operators, mine cutting and channeling machine operators, and roof bolters. As shown in Table A7, the range of occupations represented on a mine payroll range from office support, to mine management and machine operations, to construction and transportation support.

Table A41. Mine Occupation and Wages[a]

Occupation	Percentage of Total Mine Workers	Average Annual Wages (Thousand $)	Employment per Mine X = Yes 0 = No		
			Longwall	Continuous	Surface
Management, business and financial	4.49	92.2	X	X	X
Professional and related	3.69	55.3	X	X	X
Service	0.47	26.0	X	X	X
Office and administrative support	3.4	31.9	X	X	X
Supervisors, construction and extraction	5.45	67.6	X	X	X
Construction trades and related workers	18.3	33.5	X	X	X
Other construction and related workers	18.3	33.5	X	X	X
Earth drillers, except oil and gas	0.32	38.1	X	X	X
Explosive drillers, ordinance handling experts, and blasters	0.77	42.0	0	0	X
Continuous mining machine operators	4.55	41.1	X	X	0
Mine cutting and channeling machine operators	1.82	40.3	X	0	0
Roof bolters, mining	5.9	42.3	X	X	0
Helpers – extraction workers	5.84	36.6	X	X	X
Extraction workers – all other	1.54	33.7	X	X	X
Installation, maintenance and repair occupations	13.2	43.8	X	X	X
Production support	13.2	43.8	X	X	X
Transportation and material moving	21.81	38.8	X	X	X

[a]Source: [25].

The data in Table 7 describes the types of workers employed by mines. The second and third columns list the percentage of mine workers and the total wages paid to those workers, per each category in the first column. The last three columns indicates the model's assumption about whether a given mine type will employ those workers. Using these data, the expected value of wages paid to mine employees:

$$W = \sum_j O_{i,j} \times S_j \times E_{i,j} T_i \quad (17)$$

Where:
W = total annual wages to all mine employees
$O_{i,j}$ = percentage of employee of category j working in mine type i
S_j = mean annual reported salary for employee of category j
$E_{i,j}$ = 0 if category j employees are not employed at mine type i, 1 if category j employees are employed at mine type i
T_i = number of mining teams per mine type i

Expected value of the mine payroll is calculated, because it variation in the number and type of employees is not known. There are also non-miner employees that are employed, and it is not known how many of them are needed. Still, these positions – clerical, marketing, and other non-mining positions – are essential to mine operations and must be included in payroll estimation.

A.2.4 Land clearing costs

Before a resource can be mined, the land must be prepared for building construction, support roads, and mining activities. The model estimates clearing costs according to the estimation factors given by the literature [1]. It is assumed that the permitted surface area is being cleared. Permitted area is not necessarily the same as the mining area according to Equation (10), which is the area of the coal resource mined. The permitted area is all surface land that will be used for support facilities. For a surface mine, permitted area is assumed to be the same as the total mined area. However, for an underground mine, permitted area is assumed to be 25% of the total mined area. This fraction of surface land affected by underground mining is based on a 1997 ruling by Roderick Walston, which states that a maximum of 0.02 km^2 (5 acres) of support facilities are allowed for 0.08 km^2

(20 acres) of underground mining on federal lands. No data is available on the amount of surface land used for support facilities on private property, so it is assumed that the same practice holds true. The model determines clearing cost by the following:

$$CC_i = CCF_i \times Area_P^{0.9} \tag{19}$$

Where:
CC_i = clearing cost for mine type i
CCF_i = clearing cost factor for mine type i
$Area_P$ = permitted area

The clearing cost factors for surface mining and underground mining are 75,000 – 500,000 $/km^2 (300 – 2,000 $/acre) and 640,000 $/km^2 (1,600 $/acre), respectively [1].

A.2.5 Taxes

Taxes estimated by the model over the mine lifetime are summarized in Table A8. Mine taxes are paid on items purchased, as well as coal produced and sold. In the U.S., there are several environmental, health and safety regulations that levy taxes on mine operations. These taxes are predominantly paid as a function of the amount of coal that is mined; the proceeds are used to fund specific programs. Such taxes are the black lung tax and Surface Mining Control and Reclamation Act of 1977 tax. The Black Lung tax has an alternative rate, 4.40% of the price of coal if the price is less than $12/ton. However, the average U.S. price of coal is more than $12/ton, so the Black Lug tax rate based on production rate is assumed. Taxes on the sales of coal are federal income and state tax. State tax rate is assumed to be the Illinois state tax rate in this case. Taxes paid on the property and operational purchases such as fuel, electricity, and explosives, are also included.

Table A42. Mine Taxes

Tax	Rate, $/Ton	Rate, Percent	Description
Black lung	Surface, 3.00 Underground, 1.10		Paid on annual production
Capital		2	Paid on capital expenditures for equipment and surface support structures
Excise	Surface, 0.55 Underground, 1.10		Paid on annual production
Federal income		35	Paid on sales of coal, assuming 2005 U.S. price of $24.72/ton
Mineral valuation rate		1.7 – 30	Paid on the coal remaining in ground during mining operation period.
Real property tax rate		3.01	Paid on surface structure values. The model assumes that surface structure lifetime matches the maximum lifetime of the mine. The property value is adjusted by 30% for tax purposes.
Sales		6	Paid on consumables (fuel, lubricating oil, electricity, ANFO)
State income		1 – 10	Illinois state income tax rate paid on sales of coal, assuming 2005 U.S. price of $24.72/ton
Surface Mining Control and Reclamation Act of 1977	Surface, 0.35 Underground, 0.15		Paid on annual production

[a]Source: [24, 26, 27]

A.2.6 Royalties

There are several different means by which royalties can be paid to the mineral or land owner. It can be paid in a lump sum, or per ton of produced coal. The model assumes that royalties are paid on the mine production. Based on a conversation with a former mining consultant and Pennsylvania Department of Environmental Protection employee [28], it is assumed that royalties vary between 5 – 10% of sales on coal produced.

A.2.7 Permitting costs and fees

Engineering consultant costs and permitting fees are accounted in the model. A permit application can involve more expertise than is available within the company. Typically, a permit requires extensive road, drainage, ventilation, and spoil storage planning. It also requires hydrological studies, mapping, and surveying. The total cost will amount to $25,000 for a single application, which does not account for revision and resubmission in the event of a denial [29]. The model estimates permitting fees, assuming the fees necessary to open a mine in Illinois. The permitting fee in Illinois is $125/acre for surface mines, and $5/acre for underground mines [30]. The area that the permitting fee applies to is the permitted area, or area used for surface support. Undermined lands due to underground mining are not included.

A.2.8 Bonding

The model assumes that the bond amount is based on the estimated reclamation cost. Typically, bond is posted by an insurer; leading insurers are Marsh USA, Etna Casualty Insurity, and St. Paul Fire & Marine Insurance Co. The cost to the mining company is an annual premium on the insurance policy until reclamation is completed. Alternatively, a letter of credit from a financial institution may be submitted, but the model does not evaluate the cost of this option.

Based on conversations with Marsh USA personnel [28], several assumptions about bonding fees are made by the model. Bonding fees are typically 4,000 – 15,000 $/acre for surface mined lands. Prime farm land is typically bonded at 10,000 – 12,000 $/acre. These costs include the cost of filling and regrading pits, soil replacement, and revegetation. For an underground mine, the bonding cost is approximately 3,000 $/acre. This cost covers removal of the surface structures, backfilling shafts, adding 4 feet of soil over any waste disposal areas. No bond is required on undermined lands, which are referred to as "shadow area." Surface support areas include shafts, waste disposal, change rooms, conveyors. The Bureau of Land Management assumes that the bond premium is 5% of the total bond [31], but Marsh USA personnel state that reclamation bond rates are 100 – 150 basis points; in real terms, this is $10 - $15 per $1000 paid on an annual basis. The latter definition of the bond premium is assumed to be the current industry standard.

It is assumed that the mining operation must pay premiums on the bond from the time that mining starts through the time that the mine is reclaimed. In the absence of data on the amount of time that it takes to reclaim the mine, it is assumed that bond life after mining activities ends is 5 – 50 years. The bottom end of this assumption of reclamation time is based on the observation that a minimum of 10 years is required in areas of less than 26 inches, and a minimum of 5 years in areas of more than 2 feet of rainfall [32]. The top end of this range is defined at 50 years because there is little information about the total amount of time that reclamation bonds may be held as outstanding, and 50 years may be enough time to resolve reclamation requirements.

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Appendix B Notes on Chapter 3

B.1 National Coal Resource Assessment Data

As discussed in Section 2.1.4, the reported coal characteristic categories vary by region, and by coalfield within a given region. This section catalogs all the NCRA data used in the analysis by reported overburden depth, thickness, and reliability category.

Table B43. Powder River Basin Harmon coal zone (million short tons) [1]

County	Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Grand Total (MST)
Adams	0-100 feet	2.5-5 ft	3.7	20	160	110	290
	0-100 feet	5-10 ft	18	120	1000	690	1800
	0-100 feet	10-20 ft	5.5	39	250	64	360
		Total	27	180	1400	860	2500
	100-200 feet	2.5-5 ft	3.4	18	110	16	240
	100-200 feet	5-10 ft	10	52	260	22	340
	100-200 feet	10-20 ft	1.8	18	43	0	63
		Total	16	89	410	39	550
	200-500 feet	2.5-5 ft	10	22	25	0	57
	200-500 feet	5-10 ft	19	62	51	0	130
	200-500 feet	10-20 ft	39	120	68	0	220
	200-500 feet	20-40 ft	0.2	0	0	0	0.2
		Total	68	200	140	0	410
	Total		110	470	2000	900	3400
Billings	0-100 feet	2.5-5 ft	0	0	0.18	0	0.18
	0-100 feet	5-10 ft	2	10	88	0	100
	0-100 feet	10-20 ft	0	6.1	58	0	64
		Total	2	16	150	0	160
	100-200 feet	2.5-5 ft	0.81	2.1	4.2	9	16
	100-200 feet	5-10 ft	0	5.3	94	3.8	100
	100-200 feet	10-20 ft	4.4	38	92	0	130
	100-200 feet	20-40 ft	0	5.5	11	0	16
		Total	5.3	51	200	13	270
	200-500 feet	2.5-5 ft	0.072	0.84	36	36	73
	200-500 feet	5-10 ft	0.23	2.5	87	69	160
	200-500 feet	10-20 ft	9.7	52	190	0	250
	200-500 feet	20-40 ft	0.93	5.7	110	0	110
		Total	11	61	420	110	600
	500+ feet	2.5-5 ft	0	0	31	200	230
	500+ feet	5-10 ft	9.3	53	210	56	320
	500+ feet	10-20 ft	8.8	58	280	44	390
	500+ feet	20-40 ft	0	0	20	0	20
		Total	13	79	660	720	1500
	Total		31	210	1400	830	2500

Table B1, continued							
Bowman	0-100 feet	2.5-5 ft	3.3	19	71	73	170
	0-100 feet	5-10 ft	9.3	53	210	56	320
	0-100 feet	10-20 ft	13	63	440	63	580
	0-100 feet	20-40 ft	40	220	420	64	740
		Total	66	360	1100	260	1800
	100-200 feet	2.5-5 ft	16	42	24	0.1	83
	100-200 feet	5-10 ft	9.3	53	210	56	320
	100-200 feet	10-20 ft	13	63	440	63	580
	100-200 feet	20-40 ft	20	97	21	0	140
		Total	97	350	250	0.1	700
	200-500 feet	2.5-5 ft	8.2	15	6	0	29
	200-500 feet	5-10 ft	55	120	59	0	230
	200-500 feet	10-20 ft	11	30	33	0	74
		Total	74	160	98	0	330
	Total		240	870	1500	260	2800
Golden Valley	0-100 feet	2.5-5 ft	3.4	27	120	93	240
	0-100 feet	5-10 ft	10	59	160	13	240
	0-100 feet	10-20 ft	17	74	39	0	130
	0-100 feet	20-40 ft	5	16	6.9	0	27
		Total	35	170	320	110	640
	100-200 feet	2.5-5 ft	0.51	3.3	60	48	110
	100-200 feet	5-10 ft	2.5	20	170	48	240
	100-200 feet	10-20 ft	31	190	230	0	450
	100-200 feet	20-40 ft	31	210	330	22	590
		Total	65	420	780	120	1400
	200-500 feet	2.5-5 ft	0	0	42	120	160
	200-500 feet	5-10 ft	3.3	21	270	350	640
	200-500 feet	10-20 ft	5.5	63	310	190	570
	200-500 feet	20-40 ft	11	61	460	0	540
	500+ feet	2.5-5 ft	0	0.14	15	180	190
	500+ feet	5-10 ft	2.7	19	220	1200	1400
	500+ feet	10-20 ft	0	0	180	1400	1600
	500+ feet	20-40 ft	0	0	22	2.5	24
		Total	2.7	19	440	2800	3300
	Total		120	760	2600	3700	7200

Table B1, continued.							
Hettinger	0-100 feet	2.5-5 ft	0	0	0	8.4	8.4
	0-100 feet	5-10 ft	0	0	1.6	220	230
	0-100 feet	10-20 ft	0	2.8	38	72	110
		Total	0	2.8	40	310	350
	100-200 feet	2.5-5 ft	0.9	4.7	37	57	99
	100-200 feet	5-10 ft	2.9	33	240	770	1000
	100-200 feet	10-20 ft	0	0	240	1200	1400
	100-200 feet	20-40 ft	0	6.4	130	18	150
		Total	3.8	44	640	2000	2700
	200-500 feet	2.5-5 ft	1.3	8.1	68	240	310
	200-500 feet	5-10 ft	1.5	9.2	250	1900	2100
	200-500 feet	10-20 ft	9.4	75	1300	2900	4300
	200-500 feet	20-40 ft	12	89	800	570	1500
		Total	25	180	2500	5500	8200
	500+ feet	5-10 ft	0	0	0	450	450
	500+ feet	10-20 ft	0	0	0	780	780
		Total	0	0	0	1200	1200
	Total		28	230	3100	9100	13000
Slope	0-100 feet	2.5-5 ft	3.7	16	180	40	240
	0-100 feet	5-10 ft	47	240	890	130	1300
	0-100 feet	10-20 ft	27	160	1200	700	2100
	0-100 feet	20-40 ft	54	360	430	110	940
		Total	130	770	2700	980	4500
	100-200 feet	2.5-5 ft	0.33	2.1	5.3	4.6	12
	100-200 feet	5-10 ft	6.7	40	73	15	130
	100-200 feet	10-20 ft	27	190	550	7.3	770
	100-200 feet	20-40 ft	63	350	280	0	700
		Total	97	580	910	27	1600
	200-500 feet	2.5-5 ft	0.91	5.7	74	12	92
	200-500 feet	5-10 ft	8.2	64	850	250	1200
	200-500 feet	10-20 ft	32	280	2500	410	3300
	200-500 feet	20-40 ft	16	160	1100	3.9	1300
		Total	57	500	4600	670	5800
	500+ feet	2.5-5 ft	0	0	1.7	0	1.7
	500+ feet	5-10 ft	0.73	6.9	86	37	130
	500+ feet	10-20 ft	24	150	660	7.7	830
	500+ feet	20-40 ft	1.3	8.3	15	0	25
		Total	26	160	760	44	990
	Total		310	2000	8900	1700	13000

Table B1, continued.							
Stark	0-100 feet	10-20 ft	0	0	0	0.083	0.083
		Total	0	0	0	0.083	0.083
	200-500 feet	2.5-5 ft	0	0	0	64	64
	200-500 feet	5-10 ft	0	0	0	9.6	9.6
		Total	0	0	0	73	73
	500+ feet	2.5-5 ft	0	0	0	270	270
	500+ feet	5-10 ft	0	0	28	1600	1600
	500+ feet	10-20 ft	3.2	42	610	580	1200
		Total	3.2	42	640	2400	3100
	Total		3	42	640	2500	3200
Grand total			850	4600	20000	19000	45000

Table B44. Powder River Basin Hansen coal zone (million short tons) [1]

County	Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Grand total (MST)
Adams	0-100 feet	2.5-5 ft	0	0	19	1	20
	0-100 feet	5-10 ft	6.2	49	520	1200	1700
	0-100 feet	10-20 ft	6.2	48	470	200	730
		Total	12	98	1000	1400	2500
	100-200 feet	2.5-5 ft	0.083	3.9	16	5.7	25
	100-200 feet	5-10 ft	1.5	8.8	24	12	46
	100-200 feet	10-20 ft	1.1	0	0	0	1.1
		Total	2.7	13	40	18	73
	200-500 feet	2.5-5 ft	5.7	33	110	10	160
	200-500 feet	5-10 ft	42	120	220	17	390
	200-500 feet	10-20 ft	31	16	0	0	46
		Total	79	170	320	27	600
	500+ ft	5-10 ft	1.6	0.39	0	0	2
	500+ ft	10-20 ft	2.2	0.42	0	0	2.6
		Total	3.8	0.81	0	0	4.6
	Total		97	280	1400	1400	3200

Table B2, continued.							
Billings	0-100 feet	2.5-5 ft	0	0.013	5.8	0.13	5.9
	0-100 feet	5-10 ft	0	0	6.4	6.5	13
	0-100 feet	10-20 ft	0.11	3.4	2.1	18	24
		Total	0.11	3.4	14	25	43
	100-200 feet	2.5-5 ft	0	0	2.8	0	2.8
	100-200 feet	5-10 ft	0	0	0.74	0	0.74
	100-200 feet	10-20 ft	0	0	0	5.4	5.4
	100-200 feet	20-40 ft	0	0	0	21	21
		Total	0	0	3.5	27	30
	200-500 feet	2.5-5 ft	0.89	4	38	6.1	49
	200-500 feet	5-10 ft	0	6.6	59	17	82
	200-500 feet	10-20 ft	3.1	11	110	160	280
	200-500 feet	20-40 ft	0	0	0	630	630
		Total	4	21	210	810	1000
	500+ ft	2.5-5 ft	0	0	6.3	35	41
	500+ ft	5-10 ft	0	0	43	85	130
	500+ ft	10-20 ft	6.2	24	110	330	470
	500+ ft	20-40 ft	0	0	0	460	460
		Total	6.2	24	160	910	1100
	Total		10	48	390	1300	2200
Bowman	0-100 feet	2.5-5 ft	4.7	16	70	73	160
	0-100 feet	5-10 ft	8.7	42	240	270	560
	0-100 feet	10-20 ft	3.5	9.5	33	16	62
	0-100 feet	20-40 ft	0	0	0.24	0	0.24
		Total	17	67	340	360	790
	100-200 feet	2.5-5 ft	4.2	13	14	2.2	33
	100-200 feet	5-10 ft	11	40	100	25	180
	100-200 feet	10-20 ft	0.83	2.8	8.2	0	12
	100-200 feet	20-40 ft	2.2	2.5	0	0	4.7
		Total	19	59	120	27	230
	200-500 feet	2.5-5 ft	28	60	33	0.13	120
	200-500 feet	5-10 ft	38	120	210	0.91	380
	200-500 feet	10-20 ft	10	79	190	0.86	280
	200-500 feet	20-40 ft	7.9	36	21	0	65
		Total	84	300	460	1.9	840
	Total		120	420	920	390	1900

Table B2, continued.							
Golden Valley	0-100 feet	2.5-5 ft	0.88	6.6	12	2.4	22
	0-100 feet	5-10 ft	0	0.055	1.8	2.3	4.2
	0-100 feet	10-20 ft	0	0	0	5.6	5.6
		Total	0.88	6.7	14	10	32
	100-200 feet	2.5-5 ft	0.079	2.6	14	0.74	18
	100-200 feet	5-10 ft	0.14	12	88	3.4	100
	100-200 feet	10-20 ft	0	1.5	11	32	44
	100-200 feet	20-40 ft	0	0	0	32	32
		Total	0.22	16	110	68	200
	200-500 feet	2.5-5 ft	3.2	17	120	44	190
	200-500 feet	5-10 ft	6.3	58	460	250	770
	200-500 feet	10-20 ft	11	64	500	1100	1700
	200-500 feet	20-40 ft	0	0	0	880	880
		Total	20	140	1100	2300	3500
	500+ ft	2.5-5 ft	0	0.9	32	67	100
	500+ ft	5-10 ft	0	0	14	140	150
	500+ ft	10-20 ft	0	0	0	300	300
	500+ ft	20-40 ft	0	0	0	470	470
		Total	0	0.9	46	970	1000
	Total		21	160	1200	3300	4800
Hettinger	0-100 feet	5-10 ft	0	0	0.015	0.99	1
		Total	0	0	0.015	0.99	1
	100-200 feet	2.5-5 ft	0	0	6.5	27	33
	100-200 feet	5-10 ft	0	0.31	61	110	170
	100-200 feet	10-20 ft	0	9.2	19	0	28
		Total	0	9.5	86	130	230
	200-500 feet	2.5-5 ft	0.64	3.5	77	110	190
	200-500 feet	5-10 ft	3.5	32	410	550	1000
	200-500 feet	10-20 ft	2.4	5.2	16	0	24
		Total	6.5	40	500	660	1200
	500+ ft	5-10 ft	0	0	0	42	42
		Total	0	0	0	42	42
	Total		6.5	50	590	840	1500
Slope	0-100 feet	2.5-5 ft	4.1	34	260	110	400
	0-100 feet	5-10 ft	18	120	610	420	1200
	0-100 feet	10-20 ft	7.9	70	410	130	620
		Total	30	220	1300	660	2200
	100-200 feet	2.5-5 ft	0.78	14	38	0.66	53
	100-200 feet	5-10 ft	10	67	260	68	410
	100-200 feet	10-20 ft	5.1	17	81	77	180
		Total	16	98	380	150	640
	200-500 feet	2.5-5 ft	9.1	50	380	140	570
	200-500 feet	5-10 ft	18	130	920	410	1500
	200-500 feet	10-20 ft	29	220	1300	130	1700
	200-500 feet	20-40 ft	4.8	28	140	0	180
		Total	61	420	2800	670	3900
	Total		130	860	5000	1700	7600

Table B2, continued.							
Stark	500+ ft	2.5-5 ft	0	0	1.1	61	62
	500+ ft	5-10 ft	0	0	25	170	190
	500+ ft	10-20 ft	0.64	22	220	5.6	250
		Total	0.64	22	250	230	500
	Total		0.64	22	250	230	500
Grand total			380	1800	9700	9700	22000

Table B45. Powder River Basin Hagel coal zone (million short tons) [1]

County	Overburden Thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Grand Total
McLean	0-100 feet	2.5-5 ft	21	25	4.7	0	50
	0-100 feet	5-10 ft	130	120	25	0	270
	0-100 feet	10-20 ft	120	69	5.7	0	190
		Total	270	210	35	0	510
	100-200 feet	2.5-5 ft	7.3	10	5.8	0	23
	100-200 feet	5-10 ft	29	47	13	0	89
	100-200 feet	10-20 ft	23	57	15	0	95
		Total	59	110	35	0	210
	Total		330	320	70	0	720
Mercer	0-100 feet	2.5-5 ft	4.5	15	5.1	0	25
	0-100 feet	5-10 ft	9.7	10	23	0	43
	0-100 feet	10-20 ft	56	30	28	0.29	110
	0-100 feet	20-40 ft	14	35	17	0	66
		Total	84	90	74	0.29	250
	100-200 feet	2.5-5 ft	10	25	39	1.8	77
	100-200 feet	5-10 ft	12	41	66	0	120
	100-200 feet	10-20 ft	51	23	94	0	170
	100-200 feet	20-40 ft	6.4	26	25	0	57
		Total	80	120	220	1.8	420
	200-500 feet	2.5-5 ft	4.5	22	89	9.7	130
	200-500 feet	5-10 ft	2.9	14	98	0	110
	200-500 feet	10-20 ft	4.6	2.6	42	0	49
	200-500 feet	20-40 ft	3.4	5	3	0	12
		Total	15	43	230	9.7	300
	Total		180	250	530	12	970

Table B3, continued.

Oliver	0-100 feet	2.5-5 ft	16	4.4	0	0	20
	0-100 feet	5-10 ft	23	52	28	0	100
	0-100 feet	10-20 ft	310	380	110	0	800
	0-100 feet	20-40 ft	53	89	18	0	160
		Total	600	350	25	0	970
	100-200 feet	2.5-5 ft	4.1	4.3	3.8	0	12
	100-200 feet	5-10 ft	23	52	28	0	100
	100-200 feet	10-20 ft	310	380	110	0	800
	100-200 feet	20-40 ft	53	89	18	0	160
		Total	390	520	160	0	1100
	200-500 feet	2.5-5 ft	7.1	22	17	0	47
	200-500 feet	5-10 ft	32	71	93	0	200
	200-500 feet	10-20 ft	34	140	120	0	300
	200-500 feet	20-40 ft	6.4	71	45	0	120
	200-500 feet	40+ ft	1.7	0	0	0	1.7
		Total	81	300	280	0	660
	Total		1100	1200	460	0	2700
Grand total			1600	1700	1100	12	4400

Table B46. Powder River Basin Beulah-Zap coal zone (million short tons) [1]

County	Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Grand total
McLean	0-100 feet	2.5-5 ft	8.3	18	6.5	0	33
	0-100 feet	5-10 ft	40	100	23	0	170
	0-100 feet	10-20 ft	87	180	28	0	290
		Total	130	300	58	0	490
	100-200 feet	2.5-5 ft	2.8	13	3.9	0	20
	100-200 feet	5-10 ft	22	76	35	0	130
	100-200 feet	10-20 ft	23	74	31	0	130
		Total	48	160	69	0	280
	200-500 feet	2.5-5 ft	0.83	0.31	0	0	1.1
	200-500 feet	5-10 ft	1.2	6.2	7.7	0	15
	200-500 feet	10-20 ft	0.24	0.49	0	0	0.73
		Total	2.2	7	7.7	0	17
	Total		180	470	130	0	790

Table B4, continued.							
Mercer	0-100 feet	2.5-5 ft	13	26	27	3.8	70
	0-100 feet	5-10 ft	110	110	130	63	410
	0-100 feet	10-20 ft	310	210	390	310	1200
	0-100 feet	20-40 ft	75	35	18	0	130
	0-100 feet	>40 ft	0.31	0	0	0	0.31
		Total	510	380	560	380	1800
	100-200 feet	2.5-5 ft	3.4	2.3	28	2.4	36
	100-200 feet	5-10 ft	31	50	18	15	110
	100-200 feet	10-20 ft	220	190	320	130	870
	100-200 feet	20-40 ft	62	72	150	0	280
		Total	320	320	510	150	1300
	200-500 feet	2.5-5 ft	0.15	0.24	2.4	0	2.8
	200-500 feet	5-10 ft	5.1	4.3	11	0	20
	200-500 feet	10-20 ft	19	37	41	24	120
	200-500 feet	20-40 ft	6.4	34	94	0	130
		Total	31	75	150	24	280
	Total		860	770	1200	550	3400
Morton	0-100 feet	5-10 ft	0.38	0.26	0	0	0.64
		Total	0.38	0.26	0	0	0.64
	100-200 feet	5-10 ft	0.4	1.7	0	0	2.1
		Total	0.4	1.7	0	0	2.1
	200-500 feet	5-10 ft	0	0.13	0	0	0.13
		Total	0	0.13	0	0	0.13
	Total		0.78	2.1	0	0	2.8
Oliver	0-100 feet	2.5-5 ft	7.5	4.9	3.4	0	16
	0-100 feet	5-10 ft	28	47	42	0	120
	0-100 feet	10-20 ft	31	7.2	0.37	0	39
	0-100 feet	20-40 ft	0.79	0.39	0	0	1.2
		Total	67	59	46	0	170
	100-200 feet	2.5-5 ft	3	5.9	11	0	20
	100-200 feet	5-10 ft	25	110	68	0	210
	100-200 feet	10-20 ft	20	69	36	0	120
		Total	48	190	110	0	350
	200-500 feet	2.5-5 ft	1.1	4.7	0.69	0	6.5
	200-500 feet	5-10 ft	7.3	47	20	0	75
	200-500 feet	10-20 ft	5.7	21	6.4	0	34
		Total	14	73	27	0	110
	Total		130	320	190	0	640
Grand total			1200	1600	1500	550	4800

Table B47. Powder River Basin Sheridan coal resources (million short tons) [2]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total (MST)
0-100 feet	2.5-5 feet	0.16	7.6	39	0	47
0-100 feet	5-10 feet	5.4	33	140	7.7	190
0-100 feet	10-20 feet	17	120	220	5.1	360
0-100 feet	20-30 feet	7.2	83	56	0	150
0-100 feet	30-40 feet	11	36	3.6	0	51
0-100 feet	40-50 feet	29	34	0	0	63
0-100 feet	50-100 feet	38	20	34	0	92
	Total	110	330	490	13	940
100-200 feet	2.5-5 feet	0.2	5	1.6	0	6.8
100-200 feet	5-10 feet	4.4	40	41	0	85
100-200 feet	10-20 feet	17	85	120	7.5	230
100-200 feet	20-30 feet	38	190	84	0	310
100-200 feet	30-40 feet	55	100	3	0	160
100-200 feet	40-50 feet	79	76	2.1	0	160
100-200 feet	50-100 feet	100	170	12	0	280
	Total	290	660	260	7.5	1200
200-300 feet	2.5-5 feet	0.11	2.5	0.57	0	3.1
200-300 feet	5-10 feet	3.3	14	6.4	0	24
200-300 feet	10-20 feet	29	68	78	8.9	180
200-300 feet	20-30 feet	56	160	130	0.75	350
200-300 feet	30-40 feet	34	140	56	0	230
200-300 feet	40-50 feet	15	120	9.8	0	150
200-300 feet	50-100 feet	150	640	53	0	840
200-300 feet	100-150 feet	0	9.6	0	0	9.6
	Total	280	1200	330	9.6	1800
300-400 feet	2.5-5 feet	0.0061	1.1	0	0	1.2
300-400 feet	5-10 feet	8.3	16	10	0	34
300-400 feet	10-20 feet	15	62	47	2.3	130
300-400 feet	20-30 feet	36	150	230	2.2	420
300-400 feet	30-40 feet	36	210	190	0.8	430
300-400 feet	40-50 feet	16	120	58	0	190
300-400 feet	50-100 feet	220	610	78	0	900
300-400 feet	100-150 feet	9.3	5	0	0	14
	Total	340	1200	610	5.3	2100
400-500 feet	2.5-5 feet	0.22	0.76	0	0	0.98
400-500 feet	5-10 feet	9.2	36	4.2	0	49
400-500 feet	10-20 feet	11	100	73	3.7	190
400-500 feet	20-30 feet	14	85	220	8.5	320
400-500 feet	30-40 feet	17	50	140	5.6	210
400-500 feet	40-50 feet	14	55	41	0	110
400-500 feet	50-100 feet	54	250	72	0	370
400-500 feet	100-150 feet	4.1	2.5	0	0	6.6
	Total	120	580	540	18	1300

Table B5, continued.						
500-1000 feet	2.5-5 feet	1.5	2.2	0	0	3.7
500-1000 feet	5-10 feet	4.6	9.7	0	0	14
500-1000 feet	10-20 feet	15	140	170	0.16	330
500-1000 feet	20-30 feet	15	95	300	22	430
500-1000 feet	30-40 feet	7.7	80	190	16	290
500-1000 feet	40-50 feet	22	110	220	35	390
500-1000 feet	50-100 feet	100	480	670	13	1300
	Total	170	910	1500	86	2700
1000-1500 feet	20-30 feet	0	0	12	4.5	17
1000-1500 feet	30-40 feet	0	1	68	18	87
1000-1500 feet	40-50 feet	0	14	100	15	130
1000-1500 feet	50-100 feet	15	74	250	0	340
	Total	15	89	430	37	580
GRAND TOTAL		1300	4900	4200	180	11000

B48. Powder River Basin Gillette coal resources (million short tons) [3]

County	Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Grand Total
Campbell	0-100 feet	2.5-5 feet	0.94	6.5	2.1	0.099	9.6
	0-100 feet	5-10 feet	4.7	23	10	0.45	39
	0-100 feet	10-20 feet	32	100	50	0.74	190
	0-100 feet	20-30 feet	48	110	80	0	240
	0-100 feet	30-40 feet	95	320	180	0	600
	0-100 feet	40-50 feet	190	690	360	140	1400
	0-100 feet	50-100 feet	570	1800	1800	280	4400
	0-100 feet	100-150 feet	190	240	56	0	480
	0-100 feet	150-200 feet	0	5.1	0	0	5.1
		Total	1100	3300	2500	420	7400
	100-200 feet	2.5-5 feet	0.11	0.43	0.11	0	0.65
	100-200 feet	5-10 feet	0.58	0.96	1.6	0	3.1
	100-200 feet	10-20 feet	4.8	14	6.4	0	25
	100-200 feet	20-30 feet	2.8	28	15	0	46
	100-200 feet	30-40 feet	24	110	27	0	160
	100-200 feet	40-50 feet	100	460	86	0	650
	100-200 feet	50-100 feet	880	2600	950	0	4500
	100-200 feet	100-150 feet	380	660	5.8	0	1000
	100-200 feet	150-200 feet	28	56	0	0	84
		Total	1400	4000	1100	0	6500

Table B6, continued.							
	200-300 feet	10-20 feet	2.5	0.97	0	0	3.5
	200-300 feet	20-30 feet	2.9	25	2.8	0	31
	200-300 feet	30-40 feet	5.7	78	27	0	110
	200-300 feet	40-50 feet	84	390	130	0	600
	200-300 feet	50-100 feet	1300	4500	1100	0	6900
	200-300 feet	100-150 feet	510	860	88	0	1500
	200-300 feet	150-200 feet	0	11	0	0	11
		Total	1900	5800	1400	0	9100
	300-400 feet	5-10 feet	0.16	0.21	0	0	0.37
	300-400 feet	10-20 feet	1.3	4.9	18	0	25
	300-400 feet	20-30 feet	1	3.8	50	0	55
	300-400 feet	30-40 feet	9.4	10	96	0	120
	300-400 feet	40-50 feet	48	170	80	0	300
	300-400 feet	50-100 feet	1600	5300	1700	0	8600
	300-400 feet	100-150 feet	380	1000	270	0	1700
	300-400 feet	150-200 feet	11	20	0	0	31
		Total	2100	6500	2200	0	11000
	400-500 feet	5-10 feet	0.6	4	3.9	0	8.4
	400-500 feet	10-20 feet	0.72	2.2	5.3	0	8.3
	400-500 feet	20-30 feet	1.4	6.9	0.97	0	9.3
	400-500 feet	30-40 feet	4.7	22	32	2	61
	400-500 feet	40-50 feet	7	19	100	17	150
	400-500 feet	50-100 feet	1400	4600	2800	0	8800
	400-500 feet	100-150 feet	610	1600	390	0	2600
	400-500 feet	150-200 feet	3	11	0	0	14
		Total	2000	6300	3400	19	12000
	500-1000 feet	5-10 feet	0	1.3	2.7	0	4
	500-1000 feet	20-30 feet	9.1	12	0	0	21
	500-1000 feet	30-40 feet	11	15	1.6	0	27
	500-1000 feet	40-50 feet	20	63	260	86	430
	500-1000 feet	50-100 feet	2800	13000	19000	380	35000
	500-1000 feet	100-150 feet	1500	5800	10000	90	18000
		Total	4400	19000	29000	560	53000
	1000-1500 feet	20-30 feet	8.2	26	52	0	86
	1000-1500 feet	30-40 feet	0.37	48	300	0	340
	1000-1500 feet	40-50 feet	0	1.4	390	19	410
	1000-1500 feet	50-100 feet	57	450	5100	540	6100
	1000-1500 feet	100-150 feet	92	850	4200	35	5200
		Total	160	1400	10000	590	12000
	Total		13000	46000	56000	1600	110000

Table B6, continued.							
Converse	0-100 feet	2.5-5 feet	0.091	0.79	0	0	0.88
	0-100 feet	5-10 feet	0.58	4.5	2.3	0	7.4
	0-100 feet	10-20 feet	32	200	47	0	270
	0-100 feet	20-30 feet	47	200	140	0	390
	0-100 feet	30-40 feet	19	100	14	0	130
	0-100 feet	40-50 feet	9.6	60	39	0	110
	0-100 feet	50-100 feet	27	28	49	0	100
		Total	140	590	290	0	1000
	100-200 feet	2.5-5 feet	0,13	0.82	0	0	0.95
	100-200 feet	5-10 feet	0.63	4.1	15	0	20
	100-200 feet	10-20 feet	30	120	110	1.8	260
	100-200 feet	20-30 feet	44	190	120	0	360
	100-200 feet	30-40 feet	21	110	36	0	170
	100-200 feet	40-50 feet	8.3	70	12	0	90
	100-200 feet	50-100 feet	44	110	6.4	0	160
		Total	150	610	300	1.8	1100
	200-300 feet	5-10 feet	0.13	5.3	31	0	37
	200-300 feet	10-20 feet	16	67	110	1.1	200
	200-300 feet	20-30 feet	12	29	36	0	76
	200-300 feet	30-40 feet	11	62	29	0	100
	200-300 feet	40-50 feet	7.8	82	73	0	160
	200-300 feet	50-100 feet	59	170	30	0	260
	300-400 feet	5-10 feet	1.3	3.4	41	3.5	49
	300-400 feet	10-20 feet	0	1.8	45	0.74	47
	300-400 feet	20-30 feet	0	5.7	31	0	36
	300-400 feet	30-40 feet	0	0.31	44	0	44
	300-400 feet	40-50 feet	5.2	14	17	0	37
	300-400 feet	50-100 feet	50	160	54	0	260
		Total	56	180	230	4.3	470
	400-500 feet	5-10 feet	1.2	11	42	1.5	56
	400-500 feet	10-20 feet	0	0	17	0	17
	400-500 feet	20-30 feet	0	0	3.3	0	3.3
	400-500 feet	50-100 feet	0	7.6	0	0	7.6
		Total	1.2	18	62	1.5	83
	500-1000 feet	5-10 feet	4.3	31	70	0	110
	500-1000 feet	10-20 feet	0	0	2.2	0	2.2
		Total	4.3	31	72	0	110
	Total		450	1800	1300	8.6	3600
Grand total			14000	48000	51000	1800	110000

Table B49. Powder River Basin Decker coalfield (million short tons) [4]

County	Minimum overburden thickness	Total, net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total (MST)
Big horn	Exposed	2.5-5	0	1.3	0.86	0	2.2
	Exposed	5-10 feet	2.9	15	20	0	38
	Exposed	10-20 feet	20	47	140	0	210
	Exposed	20-30 feet	55	170	260	1.8	490
	Exposed	30-40 feet	40	230	310	4.6	590
	Exposed	40-50 feet	55	260	400	13	730
	Exposed	50-100 feet	92	630	1100	1.2	1800
		Total	260	1400	2200	21	3900
	0-100 feet	10-20 feet	2.4	2	26	0	30
	0-100 feet	20-30 feet	11	50	41	0	100
	0-100 feet	30-40 feet	6.7	72	130	0	210
	0-100 feet	40-50 feet	10	210	360	0	570
	0-100 feet	50-100 feet	320	1300	1900	0	3500
	0-100 feet	100-150 feet	0	3	6.7	0	9.7
		Total	350	1600	2500	0	4400
	100-200 feet	10-20 feet	0	0	2.3	0	2.3
	100-200 feet	20-30 feet	0	14	16	0	29
	100-200 feet	30-40 feet	0	26	53	0	79
	100-200 feet	40-50 feet	5.9	120	290	0	420
	100-200 feet	50-100 feet	330	1800	2000	0	4200
	100-200 feet	100-150 feet	16	92	46	0	150
		Total	360	2100	2500	0	4900
	200-300 feet	30-40 feet	0	5	32	0	37
	200-300 feet	40-50 feet	7.3	59	290	3.3	360
	200-300 feet	50-100 feet	400	1900	3100	0	5400
	200-300 feet	100-150 feet	68	160	81	0	310
	300-400 feet	30-40 feet	0	2.7	12	0	14
	300-400 feet	40-50 feet	2	29	210	32	270
	300-400 feet	50-100 feet	280	1700	2600	0	4600
	300-400 feet	100-150 feet	17	130	120	0	270
		Total	300	1900	2900	32	5100
	400-500 feet	40-50 feet	0	0	40	50	89
	400-500 feet	50-100 feet	120	880	1600	0	2600
	400-500 feet	100-150 feet	1.3	180	170	0	360
			120	1100	1800	50	3100

Table B7, continued.							
	500-1000 feet	40-50 feet	0	0	0.74	0	0.7
	500-1000 feet	50-100 feet	54	270	1800	71	2200
	500-1000 feet	100-150 feet	22	100	86	0	210
	500-1000 feet	Total	76	380	1900	71	2400
	1000-1500 feet	50-100 feet	0	0	2.3	10	12
		Total	0	0	2.3	10	12
	TOTAL		1900	11000	17000	190	30000
Powder River	Exposed	2.5-5	2.2	11	39	0.23	53
	Exposed	5-10 feet	11	54	130	4.4	200
	Exposed	10-20 feet	65	330	530	23	950
	Exposed	20-30 feet	100	420	480	86	1100
	Exposed	30-40 feet	64	320	500	100	980
	Exposed	40-50 feet	20	140	430	55	640
	Exposed	50-100 feet	14	110	530	24	680
		Total	280	1400	2600	290	4600
	0-100 feet	2.5-5	0	0.22	1	0	1.3
	0-100 feet	5-10 feet	0	0.091	3.9	0	4
	0-100 feet	10-20 feet	0	24	33	0	57
	0-100 feet	20-30 feet	0	21	100	4.3	130
	0-100 feet	30-40 feet	10	82	220	36	340
	0-100 feet	40-50 feet	8.7	83	370	34	490
	0-100 feet	50-100 feet	70	370	710	45	1200
		Total	88	580	1400	120	2200
	100-200 feet	2.5-5	0	0	0.16	0	0.16
	100-200 feet	5-10 feet	0	0	2.8	0	2.8
	100-200 feet	10-20 feet	0	3.2	4.1	0	7.3
	100-200 feet	20-30 feet	0	1.5	11	2.4	15
	100-200 feet	30-40 feet	0	3.4	88	6.9	99
	100-200 feet	40-50 feet	0.81	43	270	1.5	320
	100-200 feet	50-100 feet	53	230	770	27	1100
		Total	54	290	1100	38	1500
	200-300 feet	5-10 feet	0	0	0.33	0	0.33
	200-300 feet	10-20 feet	0	0	0.24	0	0.24
	200-300 feet	30-40 feet	0	0	49	0.68	49
	200-300 feet	40-50 feet	4.5	55	250	0	310
	200-300 feet	50-100 feet	28	170	760	23	980
		Total	33	230	1100	24	1300
	300-400 feet	30-40 feet	0	0	11	0	11
	300-400 feet	40-50 feet	18	77	180	0	280
	300-400 feet	50-100 feet	7.5	110	700	0	810
		Total	26	190	890	0	1100
	400-500 feet	40-50 feet	9.7	21	24	0	55
	400-500 feet	50-100 feet	14	100	370	0	490
		Total	24	130	400	0	540

Table B7, continued.							
	500-1000 feet	50-100 feet	1	9.7	3.9	0	15
		Total	1	9.7	3.9	0	15
	TOTAL		510	2800	7600	470	11000
Rosebud	Exposed	2.5-5	3.6	11	17	0	32
	Exposed	5-10 feet	29	99	90	0	220
	Exposed	10-20 feet	41	210	340	14	610
	Exposed	20-30 feet	23	170	210	0	410
	Exposed	30-40 feet	16	55	130	0	200
	Exposed	40-50 feet	1.9	58	90	0	150
	Exposed	50-100 feet	0.81	57	290	0	350
		Total	110	670	1200	14	2000
	0-100 feet	10-20 feet	0	2.6	8.9	0	11
	0-100 feet	20-30 feet	2.5	2.8	20	0	25
	0-100 feet	30-40 feet	2.2	7.7	24	0	34
	0-100 feet	40-50 feet	0	31	99	0	130
	0-100 feet	50-100 feet	46	260	640	0	950
		Total	51	300	790	0	1100
	100-200 feet	10-20 feet	0	0	0.36	0	0.36
	100-200 feet	30-40 feet	0	0	0.78	0	0.78
	100-200 feet	40-50 feet	0	0	12	0	12
	100-200 feet	50-100 feet	12	84	150	0	250
		Total	12	84	170	0	260
	200-300 fet	40-50 feet	0	0	0.87	0	0.87
	200-300 fet	50-100 feet	2.3	18	13	0	33
		Total	2.3	18	13	0	34
	TOTAL		180	1100	2100	14	3400
GRAND TOTAL			2600	14000	27000	680	45000

Table B50. Powder River Basin Colstrip coalfield (million short tons) [5]

County	Overburden Depth	Net Coal Thickness	Measured	Indicated	Inferred	Hypothetical	Total (MST)
Big Horn	0-100 feet	2.5-5	1.3	2.9	0.023	0	4.1
	0-100 feet	5-10 feet	14	36	6.9	0	57
	0-100 feet	10-20 feet	11	110	91	0	210
	0-100 feet	20-40 feet	13	150	100	0	260
		Total	39	290	200	0	530
	100-200 feet	2.5-5	0.093	0	0	0	0.0093
	100-200 feet	5-10 feet	4.4	5.7	0.32	0	10
	100-200 feet	10-20 feet	9.9	39	5.3	0	54
	100-200 feet	20-40 feet	70	310	92	0	470
		Total	85	350	97	0	540
	200-500 feet	5-10 feet	0.068	0.34	0	0	1
	200-500 feet	10-20 feet	21	61	4.5	0	87
	200-500 feet	20-40 feet	250	890	110	0	1300
		Total	170	950	120	0	1300

Table B8, continued.							
	500-1000 feet	5-10 feet	2.3	13	99	17	130
	500-1000 feet	10-20 feet	34	200	290	0	520
	500-1000 feet	20-40 feet	28	340	560	0	930
		Total	64	560	950	17	1600
	>1000 feet	5-10 feet	0	0	9.4	0	9.4
	>1000 feet	20-40 feet	0	0	200	0	200
		Total	0	0	210	0	210
	TOTAL		460	2200	1600	17	4200
Rosebud	0-100 feet	5-10 feet	2	3.6	0.26	0	5.8
	0-100 feet	10-20 feet	11	7.5	16	1	36
	0-100 feet	20-40 feet	0.056	0.23	0	0	0.29
		Total	13	11	16	1	42
	100-200 feet	5-10 feet	3.9	2.6	25	22	54
	100-200 feet	10-20 feet	12	33	150	27	220
	100-200 feet	20-40 feet	1.1	0.46	0	0	1.6
		Total	17	36	180	49	280
	200-500 feet	5-10 feet	9.4	77	320	130	540
	200-500 feet	10-20 feet	67	430	1600	230	2300
	200-500 feet	20-40 feet	88	410	300	0	800
		Total	160	920	2200	360	3600
	500-1000 feet	5-10 feet	6.2	30	79	42	160
	500-1000 feet	10-20 feet	22	78	960	310	1400
	500-1000 feet	20-40 feet	16	190	980	35	1200
		Total	44	300	2000	380	2700
	>1000 feet	10-20 feet	0	0	39	5.8	45
	>1000 feet	20-40 feet	0	0	410	7.7	420
		Total	0	0	450	14	460
	TOTAL		240	1300	4800	810	7100
Treasure	0-100 feet	5-10 feet	2	30	19	0	51
	0-100 feet	10-20 feet	0	5.1	1.2	0	6.4
	0-100 feet	20-40 feet	2.7	15	1.7	0	19
		Total	4.7	50	22	0	76
	100-200 feet	5-10 feet	13	34	9.6	0	56
	100-200 feet	10-20 feet	24	46	7.2	0	77
	100-200 feet	20-40 feet	22	88	5.6	0	120
		Total	58	170	22	0	250
	200-500 feet	5-10 feet	0.36	3.6	0	0	4
	200-500 feet	10-20 feet	15	150	94	0	260
	200-500 feet	20-40 feet	55	210	210	0	470
		Total	70	370	300	0	740
	500-1000 feet	10-20 feet	0.26	3.2	9.4	0	13
	500-1000 feet	20-40 feet	0.81	7.2	210	0	210
		Total	1.1	10	220	0	230
	TOTAL		130	600	560	0	1300
GRAND TOTAL			830	4000	6900	830	13000

Table B51. Powder River Basin Ashland coalfield (million short tons) [6]

County	Overburden Depth	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
Powder River	0-100 feet	10-20 feet	1.8	7.8	10	0	30
	0-100 feet	20-30	33	88	100	0	220
	0-100 feet	30-40	23	21	17	0	61
	0-100 feet	40-50	20	44	8.4	0	73
	0-100 feet	50-100	110	360	140	0	610
		Total	190	520	280	0	980
	100-200 feet	10-20 feet	0.27	0	34	2	36
	100-200 feet	20-30	17	46	52	0	110
	100-200 feet	30-40	14	20	18	0	52
	100-200 feet	40-50	43	56	49	0	150
	100-200 feet	50-100	310	720	260	0.91	1300
		Total	380	840	410	2.9	1600
	200-300 feet	10-20 feet	0	0	35	0.11	35
	200-300 feet	20-30	6.7	14	39	0	59
	200-300 feet	30-40	0	11	12	0	23
	200-300 feet	40-50	6.7	23	72	0	100
	200-300 feet	50-100	170	460	210	0	840
		Total	180	510	370	0.11	1100
	300-400 feet	10-20 feet	0	1.4	3	0	38
	300-400 feet	20-30	1.7	5.9	15	1.5	24
	300-400 feet	30-40	0	2.2	4.9	0	7.1
	300-400 feet	40-50	0	0.67	11	0	12
	300-400 feet	50-100	9.3	64	140	0	220
		Total	11	75	210	1.5	300
	400-500 feet	10-20 feet	0	0	16	0	16
	400-500 feet	20-30	1.6	0.41	6	82	8.1
	400-500 feet	30-40	0	0	0.29	0	0.29
	400-500 feet	40-50	0	0	2.9	0	2.9
	400-500 feet	50-100	0	6	66	0	72
		Total	1.6	6.4	92	0.082	100
	500-1000 feet	10-20 feet	0	2.1	24	0	26
	500-1000 feet	20-30	0	0	0.74	0	0.74
	500-1000 feet	30-40	0	0	0	0	0
	500-1000 feet	40-50	0	0	12	0	12
	500-1000 feet	50-100	0	0.36	16	0	17
		Total	0	2.4	53	0	55
	TOTAL		770	1900	1400	4.6	4100

Table B9, continued.							
Rosebud	0-100 feet	5-10 feet	0.19	0.3	0	0	0.48
	0-100 feet	10-20 feet	12	56	35	0	100
	0-100 feet	20-30	26	61	0	0	87
	0-100 feet	30-40	5.7	22	9.8	0	38
	0-100 feet	40-50	13	29	12	0	53
	0-100 feet	50-100	11	81	130	0	230
		Total	68	250	190	0	510
	100-200 feet	2.5-5	0	0.3	0	0	0.3
	100-200 feet	5-10 feet	1.1	8.3	7.8	0	17
	100-200 feet	10-20 feet	21	53	24	0	98
	100-200 feet	20-30	32	39	4.4	0	76
	100-200 feet	30-40	2.7	14	0.18	0	17
	100-200 feet	40-50	5.2	5.9	0.58	0	12
	100-200 feet	50-100	31	82	28	0	140
		Total	93	200	64	0	360
	200-300 feet	2.5-5	0.24	0.06	0	0	0.3
	200-300 feet	5-10 feet	0.36	8.8	17	0	26
	200-300 feet	10-20 feet	9.4	46	59	0	110
	200-300 feet	20-30	3.2	17	2.1	0	22
	200-300 feet	30-40	2.1	17	0.61	0	20
	200-300 feet	40-50	0	0.35	0	0	0.35
	200-300 feet	50-100	17	78	15	0	110
		Total	32	170	94	0	290
	300-400 feet	2.5-5	0.078	0.56	0.12	0	0.75
	300-400 feet	5-10 feet	2.8	9.6	38	0	50
	300-400 feet	10-20 feet	4.1	29	61	0	94
	300-400 feet	20-30	0.98	11	1.7	0	14
	300-400 feet	30-40	0	3.7	2.5	0	6.2
	300-400 feet	40-50	0	0	0	0	0
	300-400 feet	50-100	4.4	24	3.3	0	32
		Total	12	78	110	0	200
	400-500 feet	2.5-5	0.42	1.7	0.74	0	2.9
	400-500 feet	5-10 feet	1.9	11	26	0	39
	400-500 feet	10-20 feet	1.3	17	60	0	78
	400-500 feet	20-30	0	2.9	1.9	0	4.8
	400-500 feet	30-40	0	0.44	2.2	0	2.6
	400-500 feet	40-50					
	400-500 feet	50-100	1.2	9.3	0	0	11
		Total	4.8	42	91	0	140
	500-1000 feet	2.5-5	0.1	0.79	0.076	0	0.97
	500-1000 feet	5-10 feet	1	20	120	0.042	140
	500-1000 feet	10-20 feet	2.3	22	180	4.2	210
	500-1000 feet	20-30	0.37	2	3	0	5.4
	500-1000 feet	30-40	0.37	2	3	0	5.4
	500-1000 feet	40-50	0	0	0.18	0	0.18
	500-1000 feet	50-100	0	0.66	0	0	0.66
		Total	3.8	45	300	4.2	360

Table B9, continued.						
	1000-1500 feet	5-10 feet	0	0	20	0	20
	1000-1500 feet	10-20 feet	0	0.16	4.4	0	4.5
	1000-1500 feet	20-30	0	0	2.2	0	2.2
		Total	0	0.16	26	0	27
		Total	210	780	880	4.2	1900
	GRAND TOTAL	980	2700	2300	8.8	6000	

Table B52. Powder River Basin Hanna 77 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	10-20 ft	0.55	3	6.2	2.8	13
0-100 ft	40-50 ft	0.51	0.17	15	19	34
	Total	1.1	3.2	21	22	47
100-200 ft	5-10 ft	0	0.0034	0	0	0.0034
100-200 ft	10-20 ft	1.1	7.4	7.7	4.4	21
100-200 ft	40-50 ft	2.1	0.29	21	28	51
	Total	3.2	7.7	29	32	72
200-300 ft	5-10 ft	0	0.16	0	0	0.16
200-300 ft	10-20 ft	1.7	8.3	7.7	3.8	21
200-300 ft	30-40 ft	0.078	0	0	0	0.078
200-300 ft	40-50 ft	2.5	1.4	21	28	54
	Total	4.3	10	29	32	75
300-400 ft	5-10 ft	0	0.17	0	0	0.17
300-400 ft	10-20 ft	3.9	6.3	7.2	3.1	20
300-400 ft	30-40 ft	0.43	0	0	0	0.43
300-400 ft	40-50 ft	1.9	3.8	23	21	50
	Total	6.3	10	30	24	71
400-500 ft	10-20 ft	0.42	3.4	6.3	2.5	13
400-500 ft	30-40 ft	0.046	0	0	0	0.046
400-500 ft	40-50 ft	0.36	6.6	24	13	44
	Total	0.83	9.9	31	15	57
500-1000 ft	10-20 ft	0.011	1	14	10	25
500-1000 ft	40-50 ft	0	18	140	21	180
	Total	0.011	19	150	31	200
1000-1500 ft	10-20 ft	0.94	0.83	4.5	4	10
1000-1500 ft	20-40 ft	0	0	1.8	0.55	2.4
1000-1500 ft	40-50 ft	0.2	2.6	120	3.4	130
	Total	1.1	3.4	130	8	140
1500-2000 ft	5-10 ft	0.063	0	0	0	0.063
1500-2000 ft	10-20 ft	0.99	2	0.69	0.27	3.9
1500-2000 ft	20-40 ft	0	0	7.5	0	7.5
1500-2000 ft	40-50 ft	0	0	100	0	100
	Total	1.1	2	110	0.27	120

Table B10, continued.						
2000+ ft	10-20 ft	0.3	4.4	0.22	0	4.9
2000+ ft	20-30 ft	0	0.87	0.86	0	1.7
2000+ ft	30-40 ft	0	0.61	51	0	52
2000+ ft	40-50 ft	10	100	570	0	680
2000+ ft	50-100 ft	12	55	11	0	78
	Total	23	160	630	0	810
Grand total		40	230	1200	160	1600

Table B53. Powder River Basin Hanna 78 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.018	0	0	0	0.018
0-100 ft	5-10 ft	0.32	0.27	0	0	0.59
0-100 ft	10-20 ft	2.1	2.9	3.4	0	8.3
0-100 ft	20-30 ft	4.4	0	0.68	1.4	6.5
0-100 ft	30-40 ft	8.3	7	9.2	5.2	30
	Total	15	10	13	6.6	45
100-200 ft	2.5-5 ft	0.055	0	0	0	0.055
100-200 ft	5-10 ft	1.3	0.79	0	0	2.1
100-200 ft	10-20 ft	3.2	0.84	2.5	0	6.5
100-200 ft	20-30 ft	6.9	0.69	3.9	3.2	15
100-200 ft	30-40 ft	11	4.2	14	7.7	37
	Total	22	6.6	21	11	60
200-300 ft	2.5-5 ft	0.059	0	0	0	0.059
200-300 ft	5-10 ft	1	0.85	0	0	1.9
200-300 ft	10-20 ft	4	1.1	2.1	0	7.2
200-300 ft	20-30 ft	4.7	2.7	5.1	3	16
200-300 ft	30-40 ft	7.3	1.5	13	6.3	28
	Total	17	6.2	20	9.2	53
300-400 ft	2.5-5 ft	0.075	0	0	0	0.075
300-400 ft	5-10 ft	0.67	0.93	0	0	1.6
300-400 ft	10-20 ft	3.4	2.1	1.8	0	7.3
300-400 ft	20-30 ft	4.2	4.7	5.9	2.3	17
300-400 ft	30-40 ft	5.7	0.43	13	5.1	24
	Total	14	8.1	21	7.4	50
400-500 ft	2.5-5 ft	0.027	0.002	0	0	0.029
400-500 ft	5-10 ft	0.26	0.82	0	0	1.1
400-500 ft	10-20 ft	2.7	4	1.6	0	8.4
400-500 ft	20-30 ft	4	2.5	7.6	1.4	15
400-500 ft	30-40 ft	4.8	0.92	11	4.6	22
	Total	12	8.3	20	6	47
500-1000 ft	5-10 ft	0.098	5	6.3	0	11
500-1000 ft	10-20 ft	7	11	11	0	29
500-1000 ft	20-30 ft	7.9	9	33	1.2	51
500-1000 ft	30-40 ft	16	13	41	24	93
	Total	31	38	91	25	180

Table B11, continued.

1000-1500 ft	5-10 ft	0	0	0.61	0	0.61
1000-1500 ft	10-20 ft	0.12	0.57	15	0	16
1000-1500 ft	20-30 ft	0.74	4.1	14	0	19
1000-1500 ft	30-40 ft	1.7	13	37	9	60
	Total	2.5	18	67	9	96
1500-2000 ft	10-20 ft	0	0	10	0	10
1500-2000 ft	20-30 ft	0.085	4.1	12	0	16
1500-2000 ft	30-40 ft	1.3	13	45	4.4	64
	Total	1.4	17	67	4.4	90
2000+ ft	10-20 ft	0.19	6.9	30	0	37
2000+ ft	20-30 ft	0.64	27	56	0	83
2000+ ft	30-40 ft	11	83	290	0	380
2000+ ft	40-50 ft	3.3	18	2.5	0	24
	Total	15	130	370	0	520
Grand total		130	250	690	79	1100

Table B54. Powder River Basin Hanna 20 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.009	0	0	0	0.009
0-100 ft	5-10 ft	0.42	0.35	0	0	0.78
0-100 ft	10-20 ft	6.6	1.8	0.15	0	8.6
0-100 ft	20-30 ft	0.41	0	0	0	0.41
0-100 ft	30-40 ft	12	3.9	5.1	1.4	22
	Total	19	6	5.3	1.4	32
100-200 ft	5-10 ft	0.32	0.29	0	0	0.61
100-200 ft	10-20 ft	12	0.24	0.66	0	13
100-200 ft	20-30 ft	0.31	0	0	0	0.31
100-200 ft	30-40 ft	6.7	2.4	14	3.8	27
	Total	19	2.6	14	3.8	40
200-300 ft	5-10 ft	0.049	0.089	0	0	0.14
200-300 ft	10-20 ft	9.2	1.3	0.78	0	11
200-300 ft	30-40 ft	1.1	7	15	3.6	26
	Total	10	8.4	15	3.6	38
300-400 ft	10-20 ft	5.4	4.7	0.37	0	10
300-400 ft	30-40 ft	0.42	6.6	16	2.9	26
	Total	5.8	11	16	2.9	36
400-500 ft	10-20 ft	1.6	6.4	0.083	0	8.1
400-500 ft	30-40 ft	0.45	5.7	15	2.8	24
	Total	2.1	12	15	2.8	32
500-1000 ft	10-20 ft	0.035	5.6	6.9	0	13
500-1000 ft	30-40 ft	1.5	7.4	79	10	99
	Total	1.5	13	86	10	110
1000-1500 ft	10-20 ft	0	2	4.1	0	6.1
1000-1500 ft	30-40 ft	1.7	4.7	61	5.6	73
	Total	1.7	6.6	65	5.6	79

Table B12, continued.						
1500-2000 ft	5-10 ft	0	0	1.1	0	1.1
1500-2000 ft	10-20 ft	0	0.73	3.5	0	4.3
1500-2000 ft	30-40 ft	0.98	14	55	3.7	74
	Total	0.98	14	60	3.7	79
2000+ ft	5-10 ft	0	0	0.23	0	0.23
2000+ ft	10-20 ft	0	0.85	9.1	0	9.9
2000+ ft	30-40 ft	12	100	320	0	440
	Total	12	110	330	0	450
Grand total		73	180	610	34	900

Table B55. Powder River Basin Hanna 81 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.1	1.2	0	0	1.3
0-100 ft	5-10 ft	0.86	0.31	0	0	1.2
0-100 ft	10-20 ft	2	0.053	0	0	2
0-100 ft	20-30 ft	0	0	0	0	0
0-100 ft	30-40 ft	14	10	36	3.2	64
	Total	17	12	36	3.2	68
100-200 ft	5-10 ft	0.00084	0.56	0.16	0	0.72
100-200 ft	10-20 ft	0.0098	0.74	0.086	0	0.84
100-200 ft	20-30 ft	0.4	0.5	0	0	0.9
100-200 ft	30-40 ft	7.1	16	22	3.9	49
	Total	7.5	18	22	3.9	51
200-300 ft	2.5-5 ft	0	0.4	0.52	0	0.93
200-300 ft	5-10 ft	0	0.39	0.4	0	0.79
200-300 ft	10-20 ft	0.37	0.68	0.33	0	1.4
200-300 ft	30-40 ft	3.9	13	17	3.1	37
	Total	4.3	14	18	3.1	40
300-400 ft	2.5-5 ft	0	0.18	0.92	0	1.1
300-400 ft	5-10 ft	0	0.41	0.43	0	0.84
300-400 ft	10-20 ft	0.2	0.74	0.77	0	1.7
300-400 ft	30-40 ft	3.3	7.5	14	2.4	27
	Total	3.5	8.9	16	2.4	31
400-500 ft	2.5-5 ft	0	0.0049	0.73	0	0.73
400-500 ft	5-10 ft	0	0.35	0.56	0	0.91
400-500 ft	10-20 ft	0.045	1	0.7	0	1.7
400-500 ft	30-40 ft	2.9	5.1	11	1.9	21
	Total	3	6.4	13	1.9	25
500-1000 ft	2.5-5 ft	0	0	0.11	0	0.11
500-1000 ft	5-10 ft	0	0.26	3.3	0	3.5
500-1000 ft	10-20 ft	0.27	5.3	3.8	0	9.4
500-1000 ft	30-40 ft	1.2	2.1	48	3.3	54
	Total	1.5	7.6	55	3.3	67

Table B13, continued.						
1000-1500 ft	10-20 ft	0.017	7.7	8.5	0	16
1000-1500 ft	30-40 ft	0.17	1.4	43	0	45
	Total	0.18	9.1	52	0	61
1500-2000 ft	5-10 ft	0	0	0	0	0
1500-2000 ft	10-20 ft	0.0051	3.9	3.9	0	7.8
1500-2000 ft	30-40 ft	0.42	4.6	50	0	55
	Total	0.43	8.5	54	0	63
2000+ ft	5-10 ft	0	0	0.016	0	0.016
2000+ ft	10-20 ft	0	2.3	8	0	10
2000+ ft	20-30 ft	0	0	0.43	0	0.43
2000+ ft	30-40 ft	0	71	170	0	250
	Total	10	73	170	0	260
Grand total		47	160	440	18	660

Table B56. Powder River Basin Ferris 23 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	1.8	8.7	5.1	0.27	16
0-100 ft	5-10 ft	4.1	7.8	37	2.7	52
0-100 ft	10-20 ft	6.5	5.8	0.17	0	12
	Total	12	22	42	3	80
100-200 ft	2.5-5 ft	0.24	0.025	1.3	0.62	2.2
100-200 ft	5-10 ft	0.71	2.2	1.1	0.11	4.1
100-200 ft	10-20 ft	0.78	0	0	0	0.78
	Total	1.7	2.2	2.4	0.73	7.1
200-500 ft	2.5-5 ft	0.53	0.13	6.8	6.1	14
200-500 ft	5-10 ft	2.1	3.4	8.2	0.16	14
200-500 ft	10-20 ft	3.7	1.2	0	0	4.9
	Total	6.3	4.8	15	6.3	32
500-1000 ft	2.5-5 ft	0.23	0.0069	7.2	4.4	12
500-1000 ft	5-10 ft	0.78	4.1	13	0.15	18
500-1000 ft	10-20 ft	1.2	4.4	0.26	0	5.9
	Total	2.2	8.6	20	4.6	36
1000-1500 ft	2.5-5 ft	0	0	3.5	5.8	9.3
1000-1500 ft	5-10 ft	0	0	7.8	0.065	7.9
	Total	0	0	11	5.8	17
1500-2000 ft	2.5-5 ft	0	0	4.2	5.2	9.5
1500-2000 ft	5-10 ft	0	0	2.5	0.061	2.6
	Total	0	0	6.8	5.3	12
2000+ ft	2.5-5 ft	0	0	7.5	35	42
2000+ ft	5-10 ft	0	0	3.8	3.3	7.2
	Total	0	0	11	38	50
Grand total		23	38	110	64	230

Table B57. Powder River Basin Ferris 25 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.067	0.39	0.12	0	0.58
0-100 ft	5-10 ft	0.3	0.86	1.5	2.9	5.6
0-100 ft	10-20 ft	1	0.2	0	6.8	8
0-100 ft	20-30 ft	1.4	0.7	0	0.77	2.9
	Total	2.8	2.1	1.6	10	17
100-200 ft	2.5-5 ft	0.14	0.0091	0.33	0	0.56
100-200 ft	5-10 ft	0.54	1.3	1.7	6.4	9.9
100-200 ft	10-20 ft	1.7	0.21	0	7	8.9
100-200 ft	20-30 ft	0.5	0.35	0	5.9	6.8
	Total	2.8	1.9	2	19	26
200-500 ft	2.5-5 ft	0.4	0.65	3.7	1.8	6.5
200-500 ft	5-10 ft	1.7	8.9	24	33	68
200-500 ft	10-20 ft	15	23	46	33	120
200-500 ft	20-30 ft	17	9.6	0	13	40
	Total	34	42	73	81	230
500-1000 ft	2.5-5 ft	0	0	3.2	4.3	7.5
500-1000 ft	5-10 ft	0.45	2.8	13	28	45
500-1000 ft	10-20 ft	2.9	10	0.25	7.3	21
500-1000 ft	20-30 ft	1.8	6.9	0	0	8.6
	Total	5.1	20	17	40	82
1000-1500 ft	2.5-5 ft	0	0	0.051	2.6	2.7
1000-1500 ft	5-10 ft	0.81	3.2	10	21	35
1000-1500 ft	10-20 ft	0.23	0.13	0	0	0.36
	Total	1	3.4	11	23	38
1500-2000 ft	2.5-5 ft	0	0	0.01	1.2	1.2
1500-2000 ft	5-10 ft	0	0.41	9.7	14	24
	Total	0	0.41	9.7	15	25
2000+ ft	2.5-5 ft	0	0	0.0092	1.5	1.5
2000+ ft	5-10 ft	0	0	29	90	120
	Total	0	0	29	92	120
Grand total		46	70	140	280	540

Table B58. Powder River Basin Ferris 31 coal zone [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.4	0.3	1.3	0.37	2.4
0-100 ft	5-10 ft	0.087	0.33	6	0.92	7.3
0-100 ft	10-20 ft	0	0	1.8	9.1	11
0-100 ft	20-30 ft	0	0	0	1.3	1.3
	Total	0.49	0.63	9.1	12	22

Table B16, continued.						
100-200 ft	2.5-5 ft	0.094	0.035	0.021	0.36	0.51
100-200 ft	5-10 ft	0.24	0.63	0.66	1.1	2.7
100-200 ft	10-20 ft	0	0	0	7.2	7.2
100-200 ft	20-30 ft	0	0	0	0.62	0.62
	Total	0.33	0.67	0.68	9.3	11
200-500 ft	2.5-5 ft	0.68	1.5	2	2.1	6.3
200-500 ft	5-10 ft	0.6	1.9	5.4	34	42
200-500 ft	10-20 ft	0	0	0	28	28
200-500 ft	20-30 ft	0	0	0	7.3	7.3
	Total	1.3	3.4	7.4	71	83
500-1000 ft	2.5-5 ft	0	0.57	0.31	0.56	1.4
500-1000 ft	5-10 ft	0	0.39	13	19	32
500-1000 ft	10-20 ft		0	0	20	20
500-1000 ft	20-30 ft	0	0	0	0.038	0.038
	Total	0	0.96	13	39	53
1000-1500 ft	2.5-5 ft	0	0.0065	3.7	0.12	3.8
1000-1500 ft	5-10 ft	0	0.063	9.7	12	22
1000-1500 ft	10-20 ft	0	0	0	14	14
	Total	0	0.069	13	26	39
1500-2000 ft	2.5-5 ft	0	0.015	2.4	0.12	2.5
1500-2000 ft	5-10 ft	0	0.036	2.6	10	13
1500-2000 ft	10-20 ft	0	0	0	8.7	8.7
	Total	0	0.051	5	19	24
2000+ ft	2.5-5 ft	0	0.012	0.26	3.6	3.8
2000+ ft	5-10 ft	0	2	3.6	22	28
2000+ ft	10-20 ft	0	0	0	4.1	4.1
	Total	0	2	3.9	30	36
Grand total		2.1	7.8	53	210	270

Table B59. Powder River Basin Ferris 50 coal zone (million short tons) [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.36	2.1	3.4	2.4	8.3
0-100 ft	5-10 ft	0.35	0.76	7.7	16	25
0-100 ft	10-20 ft	2.3	12	19	1.5	34
0-100 ft	20-30 ft	0	0	0	0	0
	Total	3	15	30	20	67
100-200 ft	2.5-5 ft	0.14	0.39	0.8	1.5	2.8
100-200 ft	5-10 ft	1	1.4	2.5	1.8	6.7
100-200 ft	10-20 ft	0.89	3.4	4.8	0.82	9.9
100-200 ft	20-30 ft	0	0	0	0	0
	Total	2	5.2	8.1	4.1	19
200-500 ft	2.5-5 ft	0.5	0.91	1.1	0.072	2.6
200-500 ft	5-10 ft	0.58	6.6	13	3.1	24
200-500 ft	10-20 ft	1.8	6.3	8.6	0.25	17
200-500 ft	20-30 ft	0	0	0	0	0
	Total	2.8	14	23	3.4	43
Table B17, continued.						

500-1000 ft	2.5-5 ft	0.012	0.13	0.049	0.044	0.24
500-1000 ft	5-10 ft	1.1	7.6	16	0.061	25
500-1000 ft	10-20 ft	1.9	11	21	0.18	34
500-1000 ft	20-30 ft	0	0	0	0	0
	Total	3.1	19	36	0.28	59
1000-1500 ft	2.5-5 ft	0	0	0	0.033	0.033
1000-1500 ft	5-10 ft	2.3	3.7	1.6	0.0016	7.6
1000-1500 ft	10-20 ft	0.3	7.8	39	0.19	47
	Total	2.6	11	40	0.22	55
1500-2000 ft	2.5-5 ft	0	0	0	0.013	0.013
1500-2000 ft	5-10 ft	0.091	4.3	0.029	0	4.4
1500-2000 ft	10-20 ft	0	4.4	39	3.3	46
	Total	0.091	8.7	39	3.3	51
2000+ ft	2.5-5 ft	0	0	0	0.0071	0.0071
2000+ ft	5-10 ft	0	0.0056	0.025	0	0.031
2000+ ft	10-20 ft	0	0.8	160	49	210
	Total	0	0.8	160	49	210
Grand total		14	73	340	80	510

Table B60. Powder River Basin Ferris 65 coal zone (million short tons) [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0.27	1.6	0.35	0	2.2
0-100 ft	5-10 ft	4.1	11	2.4	0	17
0-100 ft	10-20 ft	0.79	4.8	0	0	5.6
0-100 ft	20-30 ft	0	0	0	0	0
	Total	5.2	17	2.7	0	25
100-200 ft	2.5-5 ft	0.23	1.3	0.65	0	2.1
100-200 ft	5-10 ft	0.4	6.9	3.5	0	11
100-200 ft	10-20 ft	1	2.6	0	0	3.7
100-200 ft	20-30 ft	0	0	0	0	0
	Total	1.7	11	4.2	0	17
200-500 ft	2.5-5 ft	1.1	3.8	9	0	14
200-500 ft	5-10 ft	0.91	7.2	54	0.98	64
200-500 ft	10-20 ft	4.9	5.1	1.1	0	11
200-500 ft	20-30 ft	0	0	0	0	0
	Total	6.9	16	65	0.98	88
500-1000 ft	2.5-5 ft	0.075	0.62	7.4	0	8.1
500-1000 ft	5-10 ft	1.5	2.5	40	0	44
500-1000 ft	10-20 ft	4.3	6.5	0	0	11
500-1000 ft	20-30 ft	0	0	0	0	0
	Total	5.9	9.6	47	0	63
1000-1500 ft	2.5-5 ft	0	0	0	0	0
1000-1500 ft	5-10 ft	0	0	4.6	0	4.6
1000-1500 ft	10-20 ft	0	0	0	0	0
	Total	0	0	4.6	0	4.6

Table B18, continued.						
1500-2000 ft	2.5-5 ft	0	0	0	0	0
1500-2000 ft	5-10 ft	0	0	0	0	0
1500-2000 ft	10-20 ft	0	0	0	0	0
	Total	0	0	0	0	0
2000+ ft	2.5-5 ft	0	0	0	0	0
2000+ ft	5-10 ft	0	0	0	0	0
2000+ ft	10-20 ft	0	0	0	0	0
	Total	0	0	0	0	0
Grand total		20	54	120	0.98	200

Table B61. Powder River Basin South Carbon coal zone (million short tons) [7]

Overburden thickness	Net coal thickness	Measured	Indicated	Inferred	Hypothetical	Total
0-100 ft	2.5-5 ft	0	0.053	0	0	0.053
0-100 ft	5-10 ft	0.78	4.9	1.5		7.3
0-100 ft	10-20 ft	2	8.9	3.3	0	14
0-100 ft	20-30 ft	2	21	5.5	0	28
0-100 ft	30-40 ft	0	8.1	6.1	0	14
0-100 ft	40+ ft	0	71	120	0	190
	Total	4.8	110	130	0	250
100-200 ft	2.5-5 ft	0.022	0.036	0	0	0.059
100-200 ft	5-10 ft	1.2	1.3	0.31	0	2.8
100-200 ft	10-20 ft	0.48	5.5	3.6	0	9.6
100-200 ft	20-30 ft	0.63	9.1	0.34	0	10
100-200 ft	30-40 ft	0	6.8	4.8	0	12
100-200 ft	40+ ft	3.4	41	39	0	84
	Total	5.8	64	49	0	120
200-300 ft	2.5-5 ft	0.044	0.011	0	0	0.055
200-300 ft	5-10 ft	1	0.064	0	0	1.1
200-300 ft	10-20 ft	0.52	1.6	0.27	0	2.4
200-300 ft	30-40 ft	0.62	6.7	0.77	0	8.1
200-300 ft	40+ ft	4.1	57	64	0	130
	Total	6.3	73	69	0	150
300-400 ft	2.5-5 ft	0.11	0.0003	0	0	0.11
300-400 ft	5-10 ft	0.89	0.65	0	0	1.5
300-400 ft	10-20 ft	2.5	6.5	0	0	9
300-400 ft	20-30 ft	0.25	11	0.63	0	12
300-400 ft	30-40 ft	0.24	9.4	0.17	0	9.8
300-400 ft	40+ ft	5.2	130	49	0	190
	Total	9.2	160	50	0	220
400-500 ft	2.5-5 ft	0.21	0	0	0	0.21
400-500 ft	5-10 ft	1.7	1.9	0	0	3.6
400-500 ft	10-20 ft	3.4	8.4	0	0	12
400-500 ft	20-30 ft	1.7	0.9	0	0	2.6
400-500 ft	30-40 ft	3.2	0.59	0	0	3.8
400-500 ft	40+ ft	48	99	0.37	0	150
	Total	58	110	0.37	0	170

Table B19, continued.						
500+ ft	2.5-5 ft	0.61	0.36	0	0	0.97
500+ ft	5-10 ft	1.7	3.6	0.48	0	5.9
500+ ft	10-20 ft	0.34	18	0.18	0	19
500+ ft	20-30 ft	4.8	11	0	0	16
500+ ft	30-40 ft	1.7	19	0	0	21
500+ ft	40+ ft	48	130	0	0	170
	Total	57	180	0.66	0	240
Grand total		140	700	300	0	1100

Table B62. Colorado Plateau Green River-Deadman coal zone (million short tons) [8]

Overburden	Net coal thickness	Measured	Indicated	Inferred	Total
0-100 ft	2.5-5 ft	0.015	0.44	2.8	3.2
0-100 ft	5-10 ft	0.35	0.54	0.38	1.3
0-100 ft	10-20 ft	5.4	12	58	75
0-100 ft	20-30 ft	11	2.3	11	24
0-100 ft	30-40 ft	0.39	0.81	0	1.2
	Total	17	16	72	110
100-200 ft	2.5-5 ft	0	0	1.5	1.5
100-200 ft	5-10 ft	0.32	2.4	1.3	4.1
100-200 ft	10-20 ft	2.4	1.1	49	52
100-200 ft	20-30 ft	25	25	6.2	56
100-200 ft	30-40 ft	0.54	0.56	0	1.1
	Total	28	30	58	120
200-300 ft	2.5-5 ft	0	0	0.18	0.18
200-300 ft	5-10 ft	0.29	1.2	3.4	4.9
200-300 ft	10-20 ft	2.9	4.2	16	23
200-300 ft	20-30 ft	18	75	150	250
200-300 ft	30-40 ft	3.1	9.5	0	13
	Total	25	90	170	290
300-400 ft	2.5-5 ft	0	0	0.082	0.082
300-400 ft	5-10 ft	0.37	1.5	4.5	6.4
300-400 ft	10-20 ft	5.5	13	18	36
300-400 ft	20-30 ft	11	93	360	470
300-400 ft	30-40 ft	2.5	9.5	0	12
	Total	20	120	380	520
400-500 ft	5-10 ft	0	0.15	5.6	5.7
400-500 ft	10-20 ft	0.3	13	8.4	22
400-500 ft	20-30 ft	0.76	32	310	340
400-500 ft	30-40 ft	0	3.8	0.66	4.4
	Total	1.1	49	320	370
500-1000 ft	5-10 ft	0	0	8.4	8.4
500-1000 ft	10-20 ft	1.3	6.4	140	140
500-1000 ft	20-30 ft	0.59	12	850	870
500-1000 ft	30-40 ft	0	0.37	11	12
	Total	1.8	19	1000	1000
1000-1500 ft	5-10 ft	0	0	0.024	0.024
1000-1500 ft	10-20 ft	0	0	230	230
1000-1500 ft	20-30 ft	0	0	14	14
	Total	0	0	240	240
Grand total		93	320	2300	2700

Table B63. Colorado Plateau San Juan Basin (million short tons) [9]

State	Overburden	Thickness	Identified	Hypothetical	Total
Colorado	0-500 ft	1.2-2.3	0	7.5	8
	0-500 ft	2.3-3.5	0	11	11
	0-500 ft	3.5-7.0	5.8	88	94
	0-500 ft	7.0-14.0	100	130	230
	0-500 ft	14.0+	1850	396	2246
		Total	1956	633	2588
	500-1000 ft	1.2-2.3	0	0	0
	500-1000 ft	2.3-3.5	0	0	0
	500-1000 ft	3.5-7.0	0	0	0
	500-1000 ft	7.0-14.0	98	1.2	99
	500-1000 ft	14.0+	1300	291.3	1600
		Total	1400	290	1700
	1000-2000 ft	1.2-2.3	0	0	0
	1000-2000 ft	2.3-3.5	0	0	0
	1000-2000 ft	3.5-7.0	0	0	0
	1000-2000 ft	7.0-14.0	100	0	100
	1000-2000 ft	14.0+	4830	390	5300
		Total	4930	390	5400
	2000-3000 ft	1.2-2.3	0	0	0
	2000-3000 ft	2.3-3.5	0	0	0
	2000-3000 ft	3.5-7.0	0	0	0
	2000-3000 ft	7.0-14.0	0	0	0
	2000-3000 ft	14.0+	21500	660	22000
		Total	21500	660	22000
	3000+ ft	1.2-2.3	0	0	0
	3000+ ft	2.3-3.5	0	0	0
	3000+ ft	3.5-7.0	0	0	0
	3000+ ft	7.0-14.0	0	0	0
	3000+ ft	14.0+	16500	1100	17600
		Total	16500	1100	17600
New Mexico	0-500 ft	1.2-2.3	68	5.4	73
	0-500 ft	2.3-3.5	63.9	10.5	74
	0-500 ft	3.5-7.0	154	68	222
	0-500 ft	7.0-14.0	1036	747.21	1783
	0-500 ft	14.0+	9140	4605	13745
		Total	10461.9	5436.11	15898
	500-1000 ft	1.2-2.3	50	1.2	51
	500-1000 ft	2.3-3.5	89.7	1.7	91
	500-1000 ft	3.5-7.0	127.9	4.9	133
	500-1000 ft	7.0-14.0	760	59.04	819
	500-1000 ft	14.0+	10040	3000	13040
		Total	11067.6	3066.84	14134

Table B21, continued.					
	1000-2000 ft	1.2-2.3	51.6	35.2	87
	1000-2000 ft	2.3-3.5	164.2	37.49	202
	1000-2000 ft	3.5-7.0	743	37.49	780
	1000-2000 ft	7.0-14.0	3110	146.5	3257
	1000-2000 ft	14.0+	29348	740	30088
		Total	33416.8	996.68	34413
	2000-3000 ft	1.2-2.3	23.7	1.2	25
	2000-3000 ft	2.3-3.5	102	9.8	112
	2000-3000 ft	3.5-7.0	540	24.9	565
	2000-3000 ft	7.0-14.0	2380	150	2530
	2000-3000 ft	14.0+	41460	8.3	41468
		Total	44505.7	194.2	44700
	3000+ ft	1.2-2.3	16.23	4.6	21
	3000+ ft	2.3-3.5	32.75	7.8	41
	3000+ ft	3.5-7.0	206	40	246
	3000+ ft	7.0-14.0	1475.1	260	1735
	3000+ ft	14.0+	67170	832	68002
		Total	68900.08	1144.4	70044
	GRAND TOTAL		214638	13911	228479

Table B64.Colorado Plateau Henry Mountains coal field (million short tons) [10]

Coal zone	Overburden	Thickness	Demonstrated	Inferred	Hypothetical	Total
Ferron	0-100-ft	2-6 ft	54.1	5.1	0	59.2
	0-100-ft	6-10 ft	6.7	2.2	0	8.9
	0-100-ft	10+ ft	6.9	0	0	6.9
	100-1000 ft	2-6 ft	81.3	187.4	12.8	281.5
	100-1000 ft	6-10 ft	20	87.4	0	107.4
	100-1000 ft	10+ ft	5.5	0	0	5.5
	1000-2000 ft	2-6 ft	4.3	103.3	16	123.6
	1000-2000 ft	6-10 ft	4.5	75.3	9.8	89.6
	1000-2000 ft	10+ ft	4	0	0	4
Total			187.3	460.7	38.6	686.6
	0-100 ft	2-6 ft	78.3	4.4		82.7
	0-100 ft	6-10 ft	107.4	7.6		115
	0-100 ft	10+ ft	172.4	20.9		193.3
	100-1000 ft	2-6 ft	172.4	20.9		193.3
	100-1000 ft	6-10 ft	118.5	75.7		194.2
	100-1000 ft	10+ ft	383.7	449.4		833.1
	1000-2000 ft	2-6 ft	1.6	0		1.6
	1000-2000 ft	6-10 ft	4.9	1.2		6.1
	1000-2000 ft	10+ ft	36.8	9.9		46.7
Total			945.7	580.4		1526.1
Grand Total			1133	1041.1	38.6	2212.7

Table B65. Colorado Plateau Yampa coalfield (million short tons) [11]

County	Overburden	Net coal thickness	Identified	Hypothetical	Total
Moffat	0-500 ft	1.2-2.3 ft	0.54	0	0.54
	0-500 ft	2.3-3.5 ft	2.1	0	2.1
	0-500 ft	3.5-7.0 ft	9	0	9
	0-500 ft	7.0-14 ft	57	0	57
	0-500 ft	14+ ft	390	0	390
	500-1000 ft	1.2-2.3 ft	0.25	0	0.25
	500-1000 ft	2.3-3.5 ft	2.1	0	2.1
	500-1000 ft	3.5-7.0 ft	14	0	14
	500-1000 ft	7.0-14 ft	210	16	226
	500-1000 ft	14+ ft	740	1.6	741.6
	1000-2000 ft	1.2-2.3 ft	5.9	2.2	8.1
	1000-2000 ft	2.3-3.5 ft	7.6	2.8	10.4
	1000-2000 ft	3.5-7.0 ft	27	14	41
	1000-2000 ft	7.0-14 ft	83	50	133
	1000-2000 ft	14+ ft	1800	340	2140
	2000-3000 ft	1.2-2.3 ft	0	1.8	1.8
	2000-3000 ft	2.3-3.5 ft	0	2.8	2.8
	2000-3000 ft	3.5-7.0 ft	0	13	13
	2000-3000 ft	7.0-14 ft	0	47	47
	2000-3000 ft	14+ ft	1500	1500	3000
	3000+ ft	1.2-2.3 ft	0	3.2	3.2
	3000+ ft	2.3-3.5 ft	0	4.8	4.8
	3000+ ft	3.5-7.0 ft	0	22	22
	3000+ ft	7.0-14 ft	0	62	62
	3000+ ft	14+ ft	79	5600	5679
Routt	0-500 ft	1.2-2.3 ft	2.5	0	2.5
	0-500 ft	2.3-3.5 ft	4.3	0	4.3
	0-500 ft	3.5-7.0 ft	17	0	17
	0-500 ft	7.0-14 ft	27	0	27
	0-500 ft	14+ ft	0.39	0	0.39
	500-1000 ft	1.2-2.3 ft	3.5	0	3.5
	500-1000 ft	2.3-3.5 ft	7.2	0	7.2
	500-1000 ft	3.5-7.0 ft	19	0	19
	500-1000 ft	7.0-14 ft	29	0	29
	500-1000 ft	14+ ft	10	0	10
	1000-2000 ft	1.2-2.3 ft	0.9	0	0.9
	1000-2000 ft	2.3-3.5 ft	0.77	0	0.77
	1000-2000 ft	3.5-7.0 ft	1.8	0	1.8
	1000-2000 ft	7.0-14 ft	1.4	0	1.4
	1000-2000 ft	14+ ft	0	0	0
	2000-3000 ft	1.2-2.3 ft	0	0	0
	2000-3000 ft	2.3-3.5 ft	0	0	0
	2000-3000 ft	3.5-7.0 ft	0	0	0
	2000-3000 ft	7.0-14 ft	0	0	0
	2000-3000 ft	14+ ft	0	0	0

Table B23, continued.					
	3000+ ft	1.2-2.3 ft	0	0	0
	3000+ ft	2.3-3.5 ft	0	0	0
	3000+ ft	3.5-7.0 ft	0	0	0
	3000+ ft	7.0-14 ft	0	0	0
	3000+ ft	14+ ft	0	0	0
		Total	5052.25	7683.2	12735.45

Table B66. Colorado Plateau South Piceance basin (million short tons) [12]

	Overburden (ft)							
Thickness	0-500	500-1000	1000-2000	2000-3000	3000-6000	6000-10000	10000+	Total
1-2.3	480	630	2500	2800	8100	6200	960	22000
2.3-3.5	340	300	1000	1600	4400	2400	150	10000
3.5-7.0	1000	1400	4100	4800	17000	12000	1100	41000
7.0-14.0	1100	1300	3000	3800	19000	19000	6600	54000
14.0+	1000	1100	2300	2000	10000	27000	1200	45000
Total	4000	4600	13000	15000	58000	67000	10000	170000

Table B67. Colorado Plateau Deserado coal area (million short tons) [13]

Coal zone	Overburden	Thickness	Cactus Reserve	Rangely NE	Total
B	0-500 ft	1.2-2.3	0.18	0.63	0.8
	0-500 ft	2.3-3.5	0.35	2.6	3
	0-500 ft	3.5-7.0	4.9	14	19
	0-500 ft	7.0-14.0	15	76	91
	0-500 ft	14.0+	0	16	16
	500-1000 ft	1.2-2.3	0.12	0	0.12
	500-1000 ft	2.3-3.5	0.23	0	0.23
	500-1000 ft	3.5-7.0	2.2	3.8	6
	500-1000 ft	7.0-14.0	21	10	31
	500-1000 ft	14.0+	7.6	0	7.6
	1000+ ft	1.2-2.3	0.22	0	0.22
	1000+ ft	2.3-3.5	0.47	0	0.47
	1000+ ft	3.5-7.0	5.2	0	5.2
	1000+ ft	7.0-14.0	28	0	28
	1000+ ft	14.0+	7.6	0	7.6
		Total	94	124	220
D	0-500 ft	1.2-2.3	0.089	4.1	4.2
	0-500 ft	2.3-3.5	0.97	7.7	8.7
	0-500 ft	3.5-7.0	9.6	20	30
	0-500 ft	7.0-14.0	10	32	42
	500-1000 ft	1.2-2.3	0.55	0.077	0.63
	500-1000 ft	2.3-3.5	1.2	1	2.2
	500-1000 ft	3.5-7.0	7	4.4	11
	500-1000 ft	7.0-14.0	16	0.81	17

Table B25, continued.					
	1000+ ft	1.2-2.3	0.15	0	0.15
	1000+ ft	2.3-3.5	1.2	0	1.2
	1000+ ft	3.5-7.0	4.3	0	4.3
	1000+ ft	7.0-14.0	28	0	28
	Total		79	70	150

Table B68. Colorado Plateau, Danforth Hills coal field (million short tons) [14]

Coal zone	Overburden (ft)	Thickness (ft)	Identified	Hypothetical	Total
FGA	0-500	2.3-3.5	2.6	0	2.6
	0-500	3.5-7.0	36.1	2.65	38.75
	0-500	7.0-14.0	240	29	269
	0-500	14.0+	265	11.3	276.3
	500-1000	2.3-3.5	1.5	0	1.5
	500-1000	3.5-7.0	55.2	0.3	55.5
	500-1000	7.0-14.0	270	35	305
	500-1000	14.0+	220	20.7	240.7
	1000-2000	2.3-3.5	0.33	0	0.33
	1000-2000	3.5-7.0	11.8	0	11.8
	1000-2000	7.0-14.0	310	38	348
	1000-2000	14.0+	370	12	382
	2000-3000	2.3-3.5	0	0	0
	2000-3000	3.5-7.0	0.22	0	0.22
	2000-3000	7.0-14.0	67	23	90
	2000-3000	14.0+	73	2.1	75.1
	3000-6000	2.3-3.5	0	0	0
	3000-6000	3.5-7.0	0	0	0
	3000-6000	7.0-14.0	5.4	110	115.4
	3000-6000	14.0+	63	72.1	135.1
			1991.15	356.15	2347.3
FGB	0-500	2.3-3.5			
	0-500	3.5-7.0	3.9	1.8	5.7
	0-500	7.0-14.0	18.4	4.8	23.2
	0-500	14.0+	1130	32	1162
	500-1000	2.3-3.5			0
	500-1000	3.5-7.0	1.4	2.6	4
	500-1000	7.0-14.0	52	14	66
	500-1000	14.0+	1150	25	1175
	1000-2000	2.3-3.5	0	0	0
	1000-2000	3.5-7.0	0	0	0
	1000-2000	7.0-14.0	71	5.6	76.6
	1000-2000	14.0+	1260	41.63	1301.63
	2000-3000	14.0+	325	39	364
	3000-6000	14.0+	174	317.3	491.3
			4185.7	483.73	4669.43

Table B26, continued.					
FGC	0-500	2.3-3.5	1.6	0	1.6
	0-500	3.5-7.0	6.5	0	6.5
	0-500	7.0-14.0	98	0	98
	0-500	14.0+	990	64	1054
	500-1000	2.3-3.5	0.64	0	0.64
	500-1000	3.5-7.0	14.5	0	14.5
	500-1000	7.0-14.0	134	0	134
	500-1000	14.0+	830	67	897
	1000-2000	2.3-3.5	0	0	0
	1000-2000	3.5-7.0	17	0	17
	1000-2000	7.0-14.0	63	0	63
	1000-2000	14.0+	580	36.6	616.6
	2000-3000	2.3-3.5	0.36	0	0.36
	2000-3000	3.5-7.0	7.6	0	7.6
	2000-3000	7.0-14.0	13	1.1	14.1
	2000-3000	14.0+	150	34	184
	3000-6000	2.3-3.5	8	0.93	8.93
	3000-6000	3.5-7.0	5.31	3.3	8.61
	3000-6000	7.0-14.0	0.37	18	18.37
	3000-6000	14.0+	78	150	228
			2997.88	374.93	3372.81
FGD	0-500	2.3-3.5	14.4	1.6	16
	0-500	3.5-7.0	38	0	38
	0-500	7.0-14.0	230	6	236
	0-500	14.0+	360	0.67	360.67
	500-1000	2.3-3.5	16	0	16
	500-1000	3.5-7.0	37	0	37
	500-1000	7.0-14.0	232	8	240
	500-1000	14.0+	300	2.2	302.2
	1000-2000	2.3-3.5	5.7	0	5.7
	1000-2000	3.5-7.0	18	0.39	18.39
	1000-2000	7.0-14.0	28.8	11	39.8
	1000-2000	14.0+	358	3	361
	2000-3000	2.3-3.5	3.28	0.1	3.38
	2000-3000	3.5-7.0	5.2	2.1	7.3
	2000-3000	7.0-14.0	5.8	10	15.8
	2000-3000	14.0+	110	3.5	113.5
	3000-6000	2.3-3.5	9.5	4.48	13.98
	3000-6000	3.5-7.0	1.02	9.1	10.12
	3000-6000	7.0-14.0	0	43	43
	3000-6000	14.0+	0	28	28
			1772.7	133.14	1905.84
FGE	0-500	2.3-3.5	3.97	0	3.97
	0-500	3.5-7.0	5.1	0	5.1
	0-500	7.0-14.0	38	0.91	38.91
	0-500	14.0+	1760	27.3	1787.3

Table B26, continued.					
	500-1000	2.3-3.5	4	0	4
	500-1000	3.5-7.0	3.99	0	3.99
	500-1000	7.0-14.0	16.9	0	16.9
	500-1000	14.0+	1560	29	1589
	1000-2000	2.3-3.5	0	0	0
	1000-2000	3.5-7.0	0	0	0
	1000-2000	7.0-14.0	10.9	0	10.9
	1000-2000	14.0+	682	48	730
	2000-3000	2.3-3.5	0	0	0
	2000-3000	3.5-7.0	0	0	0
	2000-3000	7.0-14.0	0	0	0
	2000-3000	14.0+	269	63	332
	3000-6000	2.3-3.5	0	0	0
	3000-6000	3.5-7.0	0	0	0
	3000-6000	7.0-14.0	0	0	0
	3000-6000	14.0+	295	406	701
			4648.86	574.21	5223.07
FGF	0-500	1.2-2.3	3.7	0	3.7
	0-500	2.3-3.5	1.34	0	1.34
	0-500	3.5-7.0	22.7	0	22.7
	0-500	7.0-14.0	77	0	77
	0-500	14.0+	880	45	925
	500-1000	1.2-2.3	1.1	0	1.1
	500-1000	2.3-3.5	0.71	0	0.71
	500-1000	3.5-7.0	7.31	0	7.31
	500-1000	7.0-14.0	33	0	33
	500-1000	14.0+	430	34	464
	1000-2000	2.3-3.5	0	0	0
	1000-2000	3.5-7.0	0	0	0
	1000-2000	7.0-14.0	8.2	0	8.2
	1000-2000	14.0+	341	62	403
	2000-3000	2.3-3.5	0	0	0
	2000-3000	3.5-7.0	0	0	0
	2000-3000	7.0-14.0	0	0	0
	2000-3000	14.0+	112	68.01	180.01
	3000-6000	2.3-3.5	0	0	0
	3000-6000	3.5-7.0	0	0	0
	3000-6000	7.0-14.0	0	0	0
	3000-6000	14.0+	174	312	486
			2092.06	521.01	2613.07
FGG	0-500	1.2-2.3	0.82	5.7	6.52
	0-500	2.3-3.5	2.96	2.4	5.36
	0-500	3.5-7.0	59	0.61	59.61
	0-500	7.0-14.0	231	0	231
	0-500	14.0+	93	0	93

Table B26, continued.					
	500-1000	1.2-2.3	0.04	3.8	3.84
	500-1000	2.3-3.5	0.13	1.8	1.93
	500-1000	3.5-7.0	22.38	0.73	23.11
	500-1000	7.0-14.0	56	0	56
	500-1000	14.0+	15	0	15
	1000-2000	1.2-2.3	0	4.4	4.4
	1000-2000	2.3-3.5	0	3	3
	1000-2000	3.5-7.0	6.6	2.4	9
	1000-2000	7.0-14.0	38	0	38
	1000-2000	14.0+	68	0	68
	2000-3000	1.2-2.3	0	4.4	4.4
	2000-3000	2.3-3.5	0	0	0
	2000-3000	3.5-7.0	4.5	0	4.5
	2000-3000	7.0-14.0	3.8	0	3.8
	2000-3000	14.0+	0	0	0
	3000-6000	1.2-2.3	0	7.9	7.9
	3000-6000	2.3-3.5	0	0	0
	3000-6000	3.5-7.0	9.2	9.2	18.4
	3000-6000	7.0-14.0	4.3	4.3	8.6
	3000-6000	14.0+	0	0	0
			614.73	50.64	665.37

Table B69. Colorado Plateau South Wasatch (million short tons) [15]

Overburden (ft)	Coal Thickness	Total
0-500	7-14 feet	160
0-500	14+ feet	140
500-1000	7-14 feet	420
500-1000	14+ feet	460
1000-2000	7-14 feet	310
1000-2000	14+ feet	2100
2000-3000	7-14 feet	1.4
2000-3000	14+ feet	1800
3000+	14+ feet	1200
		6591.4

Table B70. Louisiana Sabine, Chemard Lake coal zone (million short tons) [16]

Parish Name	Overburden (ft)	Thickness (ft)	Measured	Indicated	Inferred	Total
De Soto	0-100	1.5-2.5	0.4	0.38		0.79
	0-100	2.5-5	3	5.2	5.2	13
	0-100	5.0-10.0	10	18	0.33	28
	100-200	1.5-2.5	0.61	2.1	0.57	3.3
	100-200	2.5-5	6.5	27	11	54
	100-200	5.0-10.0	16	77	16	100
	100-200	10.0-20.0	25	15	0.11	40
	100-200	20.0-40.0	0.0039			0.0039
Table B28, continued.						
	200-500	1.5-2.5	0.76	1.6	5.5	7.9

	200-500	2.5-5	3.9	13	19	36
	200-500	5.0-10.0	14	39	16	69
	200-500	10.0-20.0	37	65	15	120
	200-500	20.0-40.0	0.1			0.1
Natchitoches	0-100	1.5-2.5	0.21	0.57	2.2	3
	0-100	2.5-5	0.63	4.6	6.3	12
	0-100	5.0-10.0	0.33	0.018		0.35
	100-200	1.5-2.5	4.4	8.8	23	36
	100-200	2.5-5	25	41	42	100
	100-200	5.0-10.0	2.5	5.1	10	17
	100-200	10.0-20.0				
	100-200	20.0-40.0				
	200-500	1.5-2.5	1.7	1.4	0.16	3.3
	200-500	2.5-5	21	12	2.6	36
	200-500	5.0-10.0	0.59	0.6	4.1	5.3
	200-500	10.0-20.0				
	200-500	20.0-40.0				
Red River	0-100	1.5-2.5	0.77	2.8	18	21
	0-100	2.5-5	3.4	27	47	78
	0-100	5.0-10.0	4.4	21	48	73
	100-200	1.5-2.5	2	15	47	64
	100-200	2.5-5	5.4	30	59	94
	100-200	5.0-10.0	2.8	6.3	27	36
	100-200	10.0-20.0	0.053			0.053
	100-200	20.0-40.0				
	200-500	1.5-2.5	0.088	1.2	0.71	2
	200-500	2.5-5	0.011	2.6	21	24
	200-500	5.0-10.0				
	200-500	10.0-20.0				
	200-500	20.0-40.0				
Grand Total			192.5559	443.268	446.78	1077.0969

Table B71. Central Texas coal resources (million short tons) [17]

County	Overburden (ft)	Thickness (ft)	Measured	Indicated	Inferred	Hypothetical	Total
Bastrop	0-100	1.5-2.5	6	11	8	25	25
	0-100	2.5-5	21	53	28	101	101
	0-100	5.0-10.0	21	40	9	70	70
	0-100	10.0-20.0	6	10	13	29	29
	0-100	20.0-40.0					
	100-200	1.5-2.5	2	6	3	0	12
	100-200	2.5-5	19	59	76	2	160
	100-200	5.0-10.0	38	86	62	1	190
	100-200	10.0-20.0	15	19	23	0	57
	100-200	20.0-40.0					

Table B29, continued.							
	200-500	1.5-2.5		1	2	0	3
	200-500	2.5-5	10	31	24	0	69
	200-500	5.0-10.0	21	40	37	4	98
	200-500	10.0-20.0	11	34	11	0	56
	200-500	20.0-40.0				0	
Freestone	0-100	1.5-2.5	14	54	110	45	220
	0-100	2.5-5	35	190	620	410	1200
	0-100	5.0-10.0	17	87	140	75	320
	0-100	10.0-20.0	4	19	3		26
	0-100	20.0-40.0					
	100-200	1.5-2.5	10	46	130	28	220
	100-200	2.5-5	39	200	480	86	810
	100-200	5.0-10.0	26	91	77		190
	100-200	10.0-20.0					1
	100-200	20.0-40.0					
	200-500	1.5-2.5	2	11	97	12	120
	200-500	2.5-5	6	28	82	26	140
	200-500	5.0-10.0	3	14	26		43
	200-500	10.0-20.0					
	200-500	20.0-40.0					
Lee	0-100	1.5-2.5	2	8	28		37
	0-100	2.5-5	4	13	21		38
	0-100	5.0-10.0	4	3	3		10
	0-100	10.0-20.0	1				1
	0-100	20.0-40.0					
	100-200	1.5-2.5	0	4	6		11
	100-200	2.5-5	2	14	34		50
	100-200	5.0-10.0	7	8	13		28
	100-200	10.0-20.0	9				9
	100-200	20.0-40.0	2				2
	200-500	1.5-2.5	2	8	32	3	46
	200-500	2.5-5	2	16	41		60
	200-500	5.0-10.0	2	18	19		39
	200-500	10.0-20.0	5	13	13		31
	200-500	20.0-40.0	1	6	1		9
Leon	0-100	1.5-2.5	1	3	1		6
	0-100	2.5-5	8	13	6		28
	0-100	5.0-10.0	16	21	6		44
	0-100	10.0-20.0					1
	0-100	20.0-40.0					
	100-200	1.5-2.5	3	6	11		20
	100-200	2.5-5	5	13	8		26
	100-200	5.0-10.0	12	25	9		46
	100-200	10.0-20.0	6	11	17		33
	100-200	20.0-40.0					

Table B29, continued.							
	200-500	1.5-2.5	1	3	15		19
	200-500	2.5-5	2	11	20		34
	200-500	5.0-10.0	2	11	18		31
	200-500	10.0-20.0		6	15		22
	200-500	20.0-40.0					
Limestone	0-100	1.5-2.5	6	14	31	4	55
	0-100	2.5-5	25	53	87		170
	0-100	5.0-10.0	35	59	33		130
	0-100	10.0-20.0	58	110	49		220
	0-100	20.0-40.0	7	22	2		31
	100-200	1.5-2.5	2	8	27		37
	100-200	2.5-5	8	38	120		170
	100-200	5.0-10.0	7	18	18		44
	100-200	10.0-20.0					
	100-200	20.0-40.0					
	200-500	1.5-2.5	2	12	42		55
	200-500	2.5-5	5	22	120		150
	200-500	5.0-10.0			2		3
	200-500	10.0-20.0					
	200-500	20.0-40.0					
Miliam	0-100	1.5-2.5	1	1			3
	0-100	2.5-5	6	10	4		20
	0-100	5.0-10.0	6	11			18
	0-100	10.0-20.0	15	22	4		41
	0-100	20.0-40.0					
	100-200	1.5-2.5	3	2			6
	100-200	2.5-5	35	54	18		110
	100-200	5.0-10.0	22	36	4		62
	100-200	10.0-20.0	8	7			15
	100-200	20.0-40.0					
	200-500	1.5-2.5	2	3	2		7
	200-500	2.5-5	19	23	10		52
	200-500	5.0-10.0	11	52	24		88
	200-500	10.0-20.0	19	11	2		32
	200-500	20.0-40.0					
Robertson	0-100	1.5-2.5	4	15	49	10	78
	0-100	2.5-5	17	57	73		150
	0-100	5.0-10.0	45	110	72		230
	0-100	10.0-20.0	69	130	13		21
	0-100	20.0-40.0					
	100-200	1.5-2.5	4	7	6	3	20
	100-200	2.5-5	15	41	52	6	110
	100-200	5.0-10.0	35	87	74		200
	100-200	10.0-20.0	34	59	25		120
	100-200	20.0-40.0					

Table B29, continued.							
	200-500	1.5-2.5		2	11	9	23
	200-500	2.5-5		2	22	5	29
	200-500	5.0-10.0	4	9	12		24
	200-500	10.0-20.0	17	66	49		130
	200-500	20.0-40.0					
Grand Total			971	2537	3455	954	7495

Table B72. Illinois Basin, Danville coal (million short tons) [18]

County	Coal depth	Coal Thickness	I-A	I-B	II-A
Northern IL	0-150	14-28	0	37	250
	0-150	28-42	1	110	240
	0-150	42+	10	93	86
	150+	14-28	2	44	510
	150+	28-42	70	480	390
	150+	42+	59	500	710
Western IL	0-150	14-28	0	250	180
	0-150	28-42	0	160	37
	0-150	42+	0	0	0
	150+	14-28	0	0	0
	150+	28-42	42	10	0
	150+	42+	4	33	0
West-central IL	0-150	14-28	0	0	0
	0-150	28-42	0	0	0
	0-150	42+	0	0	0
	150+	14-28	3	15	0
	150+	28-42	89	600	620
	150+	42+	17	190	240
East-central IL	0-150	14-28	6	10	39
	0-150	28-42	66	48	230
	0-150	42+	330	77	39
	150+	14-28	0	0	0
	150+	28-42	210	800	1500
	150+	42+	820	2100	1000
Southeastern IL	0-150	14-28	0	120	0
	0-150	28-42	0	4	0
	0-150	42+	0	0	0
	150+	14-28	0	0	0
	150+	28-42	82	980	1600
	150+	42+	46	810	690
Indiana	0-150	14-28	120	70	16
	0-150	28-42	430	350	73
	0-150	42+	320	180	7
	150+	14-28	540	540	72
	150+	28-42	1500	1300	73
	150+	42+	440	230	0

Table B30, continued.					
Western KY	0-150	14-28	50	97	160
	0-150	28-42	40	85	240
	0-150	42+	65	110	92
	150+	14-28	100	190	290
	150+	28-42	96	150	260
	150+	42+	280	470	580
Grand Total			5838	11243	10224

Table B73. Illinois basin, Herrin coal (million short tons) [18]

County	Coal depth	Coal Thickness	I-A	I-B	II-A
Northern IL	0-150	14-28	0	49	28
	0-150	28-42	3	130	15
	0-150	42+	78	86	6
	150+	14-28	0	0	0
	150+	28-42	18	150	130
	150+	42+	8	50	5
Western IL	0-150	14-28	0	5	10
	0-150	28-42	0	430	43
	0-150	42+	0	1500	500
	150+	14-28	0	0	0
	150+	28-42	28	94	7
	150+	42+	130	150	37
West-central IL	0-150	14-28	6	45	47
	0-150	28-42	3	180	410
	0-150	42+	75	180	43
	150+	14-28	0	0	0
	150+	28-42	180	470	2100
	150+	42+	7300	11000	5000
East-central IL	0-150	14-28	4	46	31
	0-150	28-42	2	37	17
	0-150	42+	140	330	4
	150+	14-28	0	0	0
	150+	28-42	180	750	1300
	150+	42+	1500	2300	1400
Southwestern IL	0-150	14-28	0	0	2
	0-150	28-42	0	17	0
	0-150	42+	0	2400	56
	150+	14-28	0	0	0
	150+	28-42	17	64	69
	150+	42+	5100	5400	75
Southeastern IL	0-150	14-28	2	1	0
	0-150	28-42	13	34	0
	0-150	42+	18	560	0
	150+	14-28	0	0	0
	150+	28-42	150	640	4080
	150+	42+	4300	7300	9300

Table B31, continued.					
Western KY	0-150	14-28	9	20	17
	0-150	28-42	13	25	37
	0-150	42+	87	120	230
	150+	14-28	29	46	63
	150+	28-42	64	170	230
	150+	42+	270	460	740
Grand Total			19727	35239	26032

Table B74. Illinois Basin Springfield coal (million short tons) [18]

County	Coal depth	Coal Thickness	I-A	I-B	II-A
Northern Illinois	0-150	14-28	0	0	0
	0-150	28-42	0	0	0
	0-150	42+	63	30	8
	150+	14-28	0	0	0
	150+	28-42	7	120	2000
	150+	42+	0	240	2200
Western Illinois	0-150	14-28	0	190	190
	0-150	28-42	0	330	130
	0-150	42+	0	1200	0
	150+	14-28	0	0	0
	150+	28-42	0	0	68
	150+	42+	0	480	0
West-central IL	0-150	14-28	0	0	0
	0-150	28-42	0	0	0
	0-150	42+	0	790	340
	150+	14-28	0	0	0
	150+	28-42	12	130	2300
	150+	42+	1200	4600	9800
East-central IL	0-150	14-28	3	8	5
	0-150	28-42	2	1	5
	0-150	42+	6	7	0
	150+	14-28	0	0	0
	150+	28-42	81	390	1200
	150+	42+	560	1500	1700
Southwestern IL	0-150	14-28	0	12	0
	0-150	28-42	0	82	15
	0-150	42+	0	230	19
	150+	14-28	0	0	0
	150+	28-42	0	27	62
	150+	42+	70	220	6
Southeastern IL	0-150	14-28	0	0	0
	0-150	28-42	0	4	0
	0-150	42+	2	370	0
	150+	14-28	0	0	0
	150+	28-42	160	970	4300
	150+	42+	3900	7600	11700

Table B32, continued.					
Western KY	0-150	14-28	0	0	1
	0-150	28-42	3	5	9
	0-150	42+	160	300	500
	150+	14-28	3	4	1
	150+	28-42	47	68	67
	150+	42+	840	1900	3100
			7119	21808	39726

As shown in Table B1 – B32, reporting categories vary throughout the NCRA. The variation among the reports, and their lack of consistency with official USGS coal resource reporting criteria are summarized in Table B33.

Table B75. Compliance with USGS coal resource reporting criteria

Coal seam name	Overburden depth	Thickness	Reliability categories
Colorado Plateau			
Danforth Hills	●	◗	●
Deserado	●	◗	❍
South Piceance	●	◗	❍
South Wasatch	●	◗	❍
Yampa	●	●	●
Henry Mountains	◗	◗	◗
San Juan	●	●	●
Rocky Mountains and Great Plains			
Ashland	●	●	●
Colstrip	●	●	●
Decker	◗	●	●
Gillette	●	●	●
Sheridan	●	●	●
Williston-Beulah Zap	●	●	●
Williston-Hagel	●	●	●
Williston-Hansen	●	●	●
Williston-Harmon	●	●	●
Hanna-Ferris 23,25,31,50,65	●	●	●
Hanna-Hanna 7, 78, 79, 81	●	●	●
Carbon-Johnson	●	●	●
Green River-Deadman	●	●	●
Gulf Coast			
Wilcox	●	●	●
Upper Wilcox	●	●	●
Northern and Central Appalachia			
Pittsburgh	●	●	❍
Upper Freeport	●	◗	❍
Lower Kittanning	●	◗	❍
Pond Creek	●	◗	❍
Fire Clay	●	◗	❍
Pocohontas	●	◗	❍
Illinois Basin			
Springfield	◗	●	◗
Herrin	◗	●	◗
Danville	◗	●	◗

● = USGS defined categories
◗ = Self defined categories
❍ = No categories

As shown in Table B75, western coal data adheres to the USGS guidelines, while other resources often include self defined categories. Resources reported in the Rocky Mountains and Great Plains and Colorado Plateau reports follow the USGS coal depth and thickness categories. Data categorization in the Illinois and Northern and Central Appalachia reports is less consistent. The Colorado Plateau South Piceance coalfield reported quantities of coal per USGS defined reliability category, but did not further categorize this coal by depth and thickness. To ascertain the amount of coal per reliability category, it was assumed that the ratio of identified to hypothetical resource was constant throughout the coal zone. Coal reliability categories were ignored in the Northern and Central Appalachia resource report. This report also did not tabulate the coal resource per coal thickness and depth; the data was estimated from plots of estimated coal. The Illinois report created their own categories – I-A, I-B and II-C – which are assumed to be the equivalent of “measured”, “indicated” and “hypothetical, although no explicit definition with respect to estimation distance form the borehole is provided [19]. The overburden depth data was not as detailed in the Illinois and Appalachia reports. A maximum measured depth of 1,500 feet was reported for Illinois seams [20]. However, the maximum overburden category provided was 150+ feet [21]. The Kittanning seam in Northern Appalachia reported all of its coal to lie at 700+ feet depths, while the Pocohontas seam reported a total range of overburden depth without categorizing the resource by depth. Depths through 10,000 feet were reported for western seams. The lack of further definition in Illinois and Appalachian resources adds to the uncertainty in its geological profile. While many reports complied with the USG guidelines to describe the coal resource assessed, the discontinuity in reporting categories appears to be arbitrary, with maximum overburden and coal thickness definitions varying throughout. The lack of consistency makes them difficult to compare, and does not lend itself to accurate portrayal of the distribution of coal thickness and depths. Knowing that coal is more than 150 or 700 feet underground does not aid in extraction planning, when it is necessary to consider the true depth of the coal before investing in its development.

B.2 Model input and simulation

As discussed in Section 3.2, available resource is adjusted by using the simulated recovery rate of each mine type per each region, as shown in Table B35.

Table B76 Estimated recovery rates, *r*, used to calculate adjusted coal resource (*AdjCR*)

Coalfield, *i*	LW			CM			SM		
	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Danforth Hills	NA	NA	NA	NA	NA	NA	0.99	1.00	1.00
Deserado	NA	NA	NA	NA	NA	NA	0.84	0.94	0.98
South Piceance	0.88	0.89	0.96	0.38	0.63	0.82	0.83	0.94	0.98
South Wasatch	0.88	0.89	0.96	0.55	0.63	0.83	0.93	0.96	0.98
Yampa	0.88	0.89	0.96	0.36	0.61	0.80	0.86	0.94	0.98
Henry Mountains	0.88	0.89	0.96	0.44	0.65	0.86	0.84	0.93	0.98
San Juan	0.88	0.89	0.96	0.41	0.62	0.81	0.86	0.95	0.98
Ashland	0.66	0.75	0.95	0.56	0.62	0.79	0.96	0.99	1.00
Colstrip	0.77	0.86	0.95	0.60	0.72	0.89	0.93	0.97	0.99
Decker	0.61	0.67	0.95	0.60	0.79	0.98	0.98	0.99	1.00
Gilette	0.59	0.65	0.95	0.58	0.65	0.84	0.98	0.99	1.00
Sheridan	0.61	0.67	0.95	0.58	0.66	0.84	0.97	0.99	1.00
Williston-Beulah-Zap	0.77	0.87	0.96	0.72	0.78	0.92	0.93	0.97	0.99
Williston-Hagel	0.78	0.86	0.96	0.73	0.87	0.98	0.92	0.97	0.99
Williston-Hansen	0.78	0.88	0.96	0.69	0.78	0.92	0.90	0.97	0.99
Williston-Harmon	0.78	0.85	0.96	0.71	0.78	0.91	0.92	0.97	0.99
Hanna-Ferris 23, 25,31,50,65	NA	NA	NA	NA	NA	NA	0.89	0.95	0.98
Hanna-Hanna 77,78,79,81	NA	NA	NA	NA	NA	NA	0.97	0.99	1.00
Carbon-Johnson	0.74	0.79	0.96	0.74	0.87	0.97	0.95	0.98	0.99
Green River-Dead Man	0.77	0.84	0.96	0.59	0.73	0.88	0.94	0.98	0.99
Wilcox	0.78	0.88	0.96	0.69	0.85	0.97	0.85	0.96	0.99
Lower Wilcox	0.78	0.88	0.96	0.69	0.82	0.95	0.87	0.96	0.99
Pittsburgh	0.88	0.89	0.96	0.42	0.71	0.94	0.78	0.93	0.97
Upper Freeport	0.88	0.89	0.96	0.54	0.72	0.91	0.87	0.94	0.97

Table B35, continued.									
Lower Kittaning	0.88	0.89	0.96	0.33	0.35	0.39	0.61	0.80	0.92
Pond Creek	0.88	0.89	0.96	0.37	0.60	0.76	0.79	0.93	0.97
Fire Clay	0.88	0.89	0.96	0.40	0.66	0.87	0.79	0.92	0.97
Pocohontas	0.88	0.89	0.96	0.34	0.58	0.80	0.77	0.93	0.97
Springfield	0.88	0.89	0.96	0.37	0.52	0.78	0.65	0.81	0.93
Herrin	0.88	0.89	0.96	0.37	0.58	0.81	0.54	0.88	0.96
Danville	0.88	0.89	0.96	0.37	0.52	0.79	0.66	0.80	0.93

B.3 Alternate EIA demand cases

As discussed in Section 2.2, the EIA evaluates several alternate energy planning scenarios. Coal demand varies accordingly. This section shows the demand curves based on the EIA projected coal demand per each case.

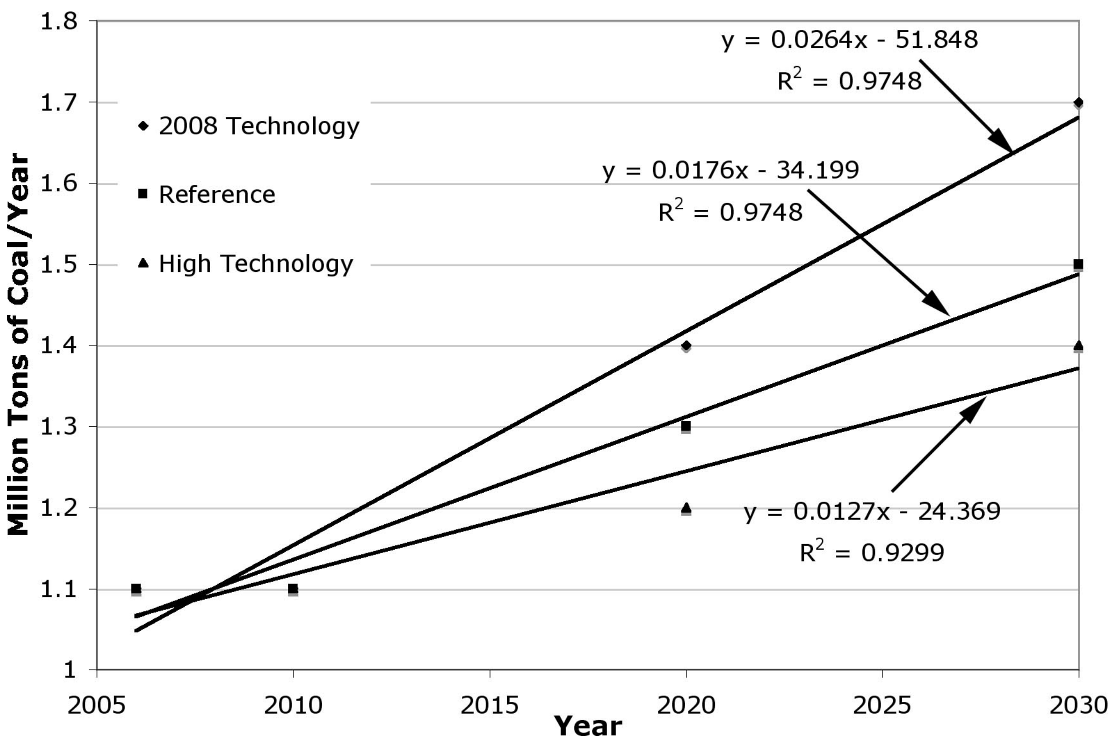

Figure B30 Coal demand projected by EIA integrated technology case

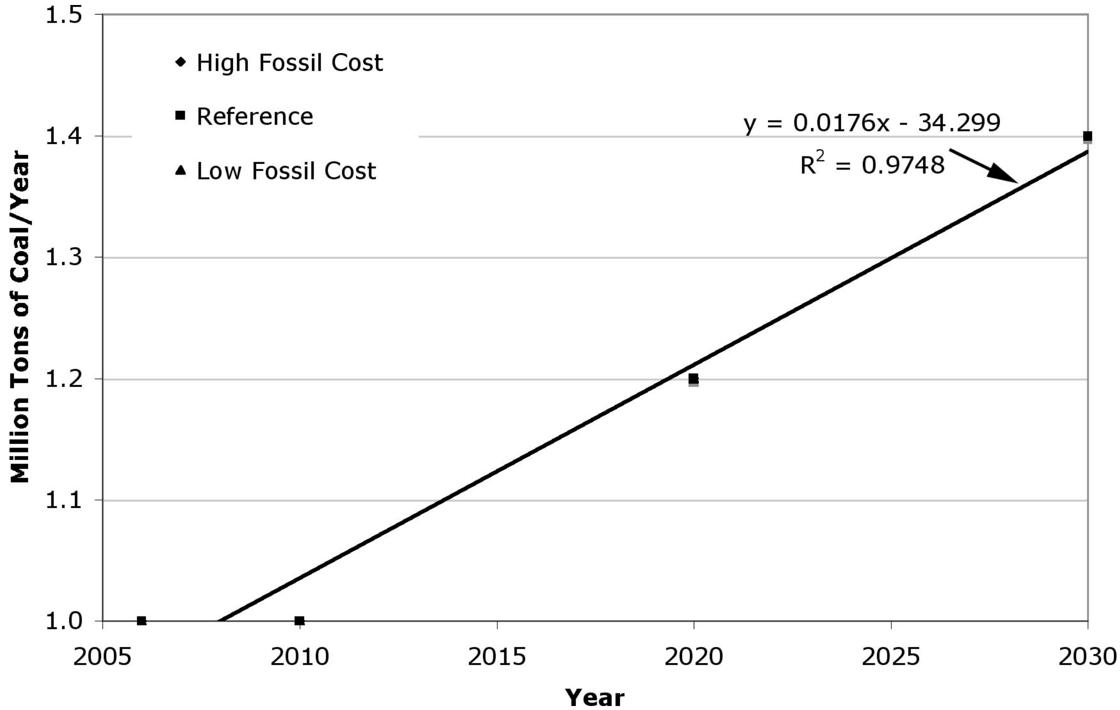

Figure B31. Coal demand projected by EIA fossil technology case

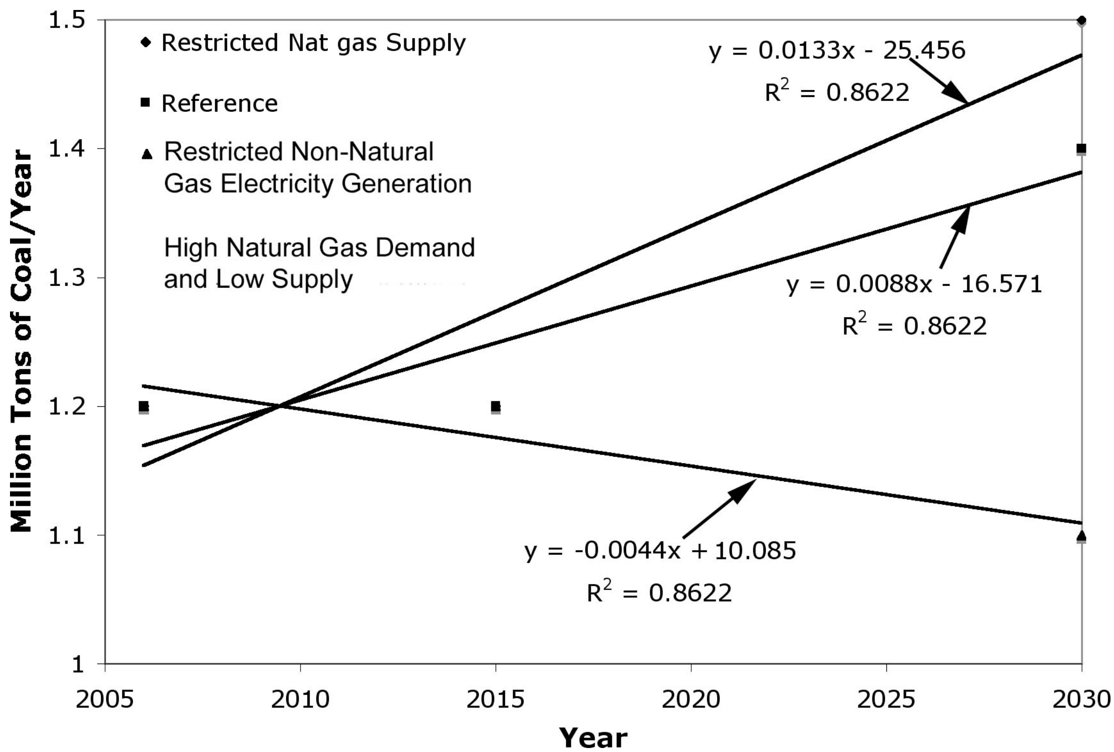

Figure B32 Coal demand projected by EIA natural gas case. Restricted non-natural gas electricity generation case and high natural gas demand and low supply case are the same.

Table B77. Comparison of EIA reference case estimates per demand scenario (billion tons of coal)[a]

	Year			
Scenario Name	**2006**	**2010[b]**	**2020**	**2030**
Economic growth	1.1	1.2	1.3	1.4
Oil price	1.1	1.1	1.3	1.5
Integrated technology	1.1	1.1	1.3	1.5
Fossil technology	1	1	1.2	1.4
Coal cost	1.2	1.2[b]	NA	1.5
Natural gas supply and demand	1.2	1.2[b]	NA	1.4

[a]In all but the coal cost scenario, fuel demand is reported as quadrillion BTU. Values reported here are based on conversion using the EIA consumption conversion factor of 20.183 million BTU per short ton of coal [11].
[b]In coal cost and natural gas supply and demand scenarios, 2015 estimates are given.

B.4 Estimated mining costs

As discussed in Section 6, estimated mining costs vary considerably, based on recovery rate.

Table B78 shows the range of cost by mining method. Although 95th percentile costs accounts for the highest resource recovery rate, are the most costly because they assume the 95th percentile (or highest) equipment and operating costs.

Table B78 Estimated mining cost per region by mine type ($/ton of coal produced). The 5th, 50th and 95th percentile estimated costs are shown.

Coal Region	Coalfield	Longwall			Continuous			Surface		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills							4	8	13
	Deserado							12	64	400
	South Piceance	23	31	91	25	35	68	46	321	1519
	South Wasatch	19	25	41	22	30	42	24	319	1387
	Yampa	21	31	98	23	35	68	40	422	2412
	Henry Mountains	24	35	69	27	38	66	30	235	1307
	San Juan	20	28	71	24	32	58	52	349	1845
Rocky Mountains and Great Plains	Ashland	17	21	31	20	27	35	16	92	556
	Colstrip	17	23	54	20	29	39	13	63	433
	Decker	17	21	31	20	27	35	5	16	69
	Gilette	17	21	29	20	27	35	9	32	152
	Sheridan	17	21	29	20	27	35	9	34	136
	Williston-Beulah-Zap	17	22	51	20	27	40	10	34	144
	Williston-Hagel	17	22	54	20	27	42	7	20	87
	Williston-Hansen	17	24	61	21	29	52	11	38	153
	Williston-Harmon	17	22	51	20	28	41	7	18	81
	Hanna-Ferris 23, 25,31,50,65							14	69	262
	Hanna-Hanna 77,78,79,81							9	30	95
	Carbon-Johnson	17	21	34	20	27	37	11	99	680
	Green River-Dead Man	17	22	38	21	28	36	6	17	80
Gulf Coast	Wilcox	18	25	86	21	30	73	7	23	151
	Lower Wilcox	17	25	89	21	30	66	8	22	126
	Pittsburgh	24	39	103	25	43	87	15	133	1110
Appalachia	Upper Freeport	22	33	62	24	36	58	15	132	795
	Lower Kittaning	64	88	178	57	80	150	1120	3283	11099
	Pond Creek	24	39	123	26	43	84	49	389	2596
	Fire Clay	24	38	117	25	40	94	15	204	1545
	Pocohontas	23	39	101	27	45	74	49	451	3604
Illinois	Springfield	55	80	148	49	76	133	44	461	3980
	Herrin	28	55	328	31	58	197	32	204	1536
	Danville	57	79	171	55	76	133	49	485	3505

References

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Appendix C. Notes for Chapter 4

C.1 Subsidence estimation methods

There are several accepted subsidence estimation methods. The most common approach is to empirically develop subsidence factors for the region or coal seam of interest. The subsidence factor may be based on rock properties [1], or subsidence measurements over time. There are several references that provide subsidence factors for various regions of the country, and recommend finite element analysis to estimate exact subsidence profiles and time lapses [1-3]. However, finite element analysis of subsidence requires field measurements and complicated mathematical modeling. Simplified empirically developed equations are used to estimate final total subsidence, instead of finite element analysis, in this evaluation.

Figure C33 shows the subsidence area and depth relative to the seam depth and longwall panel width. The geometry of the subsidence profile is estimated and used to calculate maximum subsidence. Figure C34 shows the subsidence area relative to the longwall panel length. The area of subsidence over longwall panels is determined by estimating the length and width of expected subsidence, based on panel dimensions, critical width, and critical radius. Although the diagram shows critical width as being half of the panel width, this may not always be the case, depending on how deep the seam lies. The footprint extends beyond the longwall panel, as shown in Figure C33 and Figure C34. Figure C35 shows the location and size of a subsidence chimney relative to the pillars left behind in a continuous mine. Typically, the diameter of these chimney sinkholes ranges from w to $w\sqrt{2}$ [2]. The entry width between pillars, w, is defined in Chapter 2. However, a method that calculates continuous mining subsidence area as a function of seam depth and mining height is used instead of the rule of thumb based on entry width.

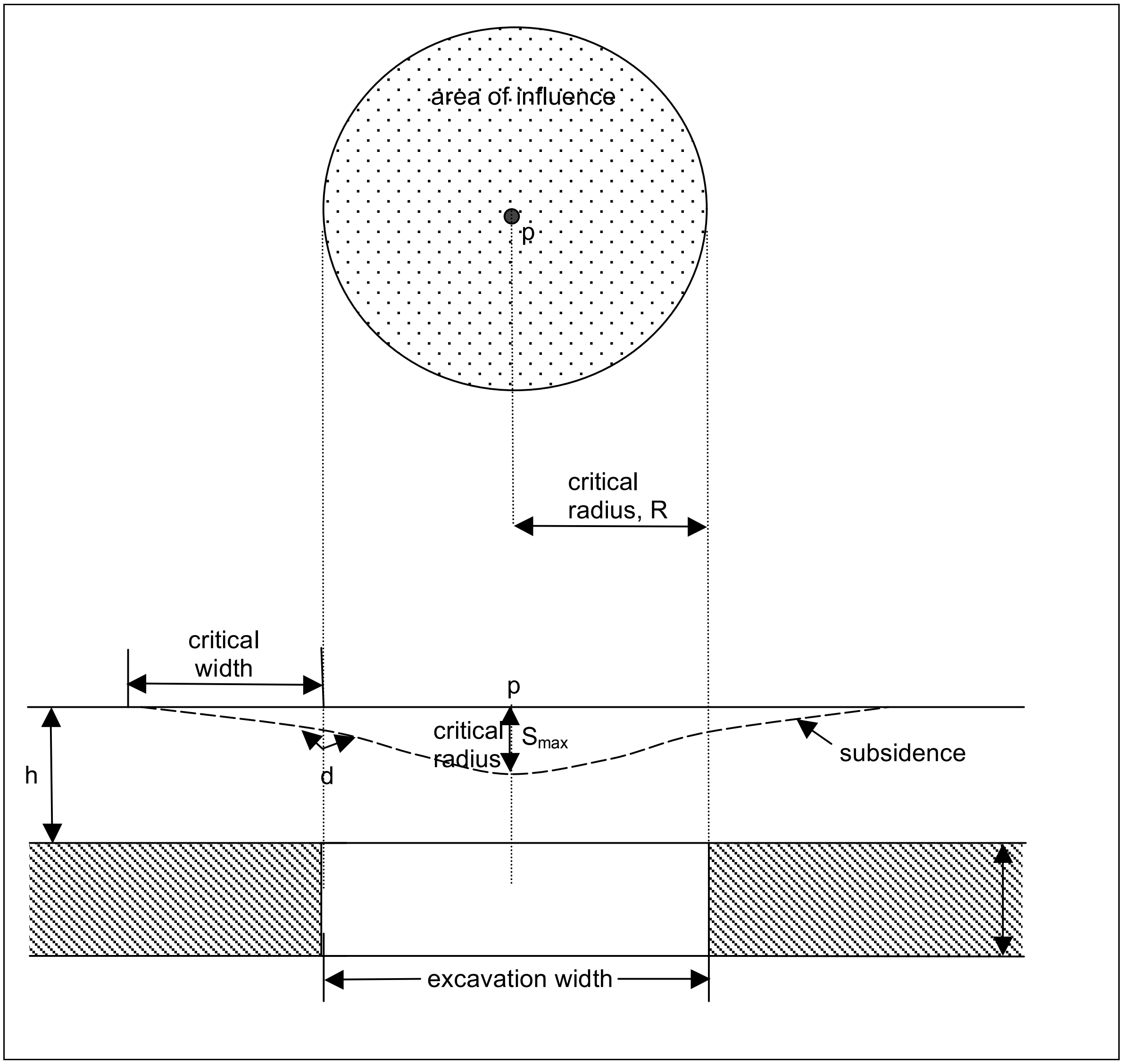

Figure C33. Subsidence variables. Diagram not to scale.

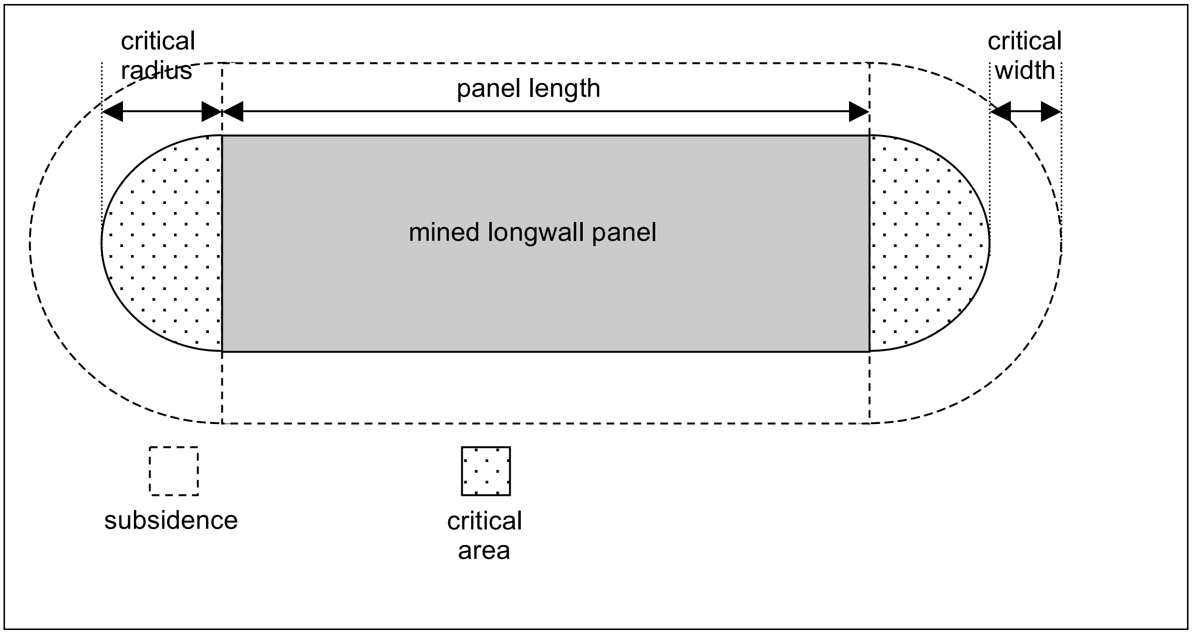

Figure C34. Longwall subsidence variables

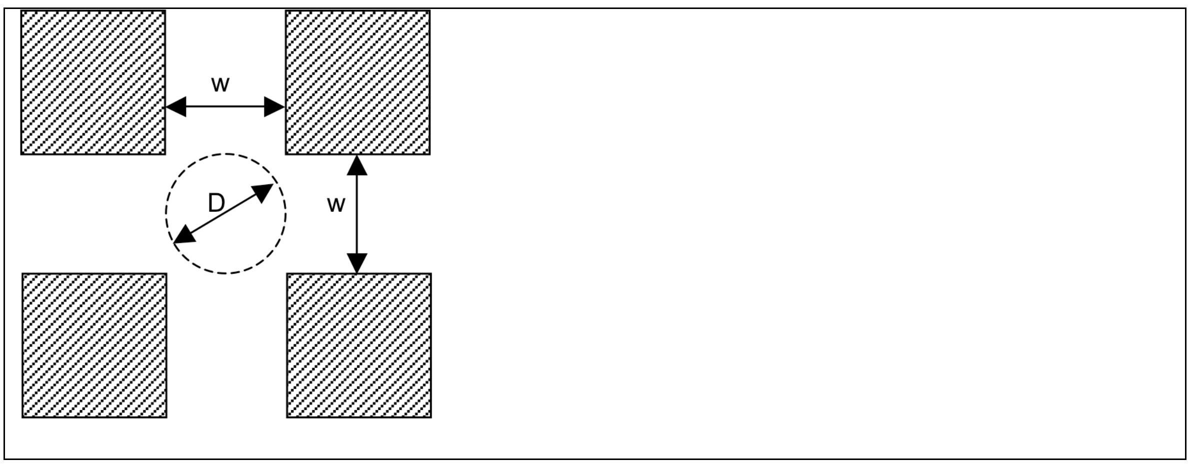

Figure C35. Continuous mine subsidence variables

An empirical-based approach, applicable throughout the country [4] is used to estimate subsidence area and depth. This method can be used to gain a general idea of expected subsidence based on prevalent geological conditions and mining operations. It was developed by observing underground mine subsidence in the Illinois and Appalachian coal basins [4]. Overburden depth, seam height, the size of the underground mine workings were measured. These were used to develop equations to estimate The subsidence factor, offset distance of inflection point, and major influence radius, subsidence area and maximum subsidence depth, subsidence factor, offset distance of inflection point, and major influence radius. These variables are shown in Figure C33 –

Figure C35 and are estimated. Equations 1 – 3 are used to estimate longwall subsidence area.

$$a = 1.9381(h + 23.4185)^{-0.1884} \quad [4] \qquad (1)$$

$$d = h(0.382075 \times 0.999253^{h}) \quad [4] \qquad (2)$$

$$R = \frac{h}{\tan\beta} \quad [4] \qquad (3)$$

where a = subsidence factor
h = overburden depth (see Figure C1)
d = offset distance of inflection point (see Figure C1)
R = radius of major influence or angle of major influence (shown in Figure C1)
$tan\beta$ = 3

Equations 4 – 6 estimate continuous mine subsidence area.

$$a = \rho(0.7247 - 2.4733 \times 10^{-5} h = 1.9585 \times 10^{-7} h^{2}) \quad [4] \qquad (4)$$

$$d = h(0.380275 \times 0.999253^{h}) \quad [4] \qquad (5)$$

$$R = \frac{h}{\sqrt{\rho}\tan\beta} \quad [4] \qquad (6)$$

where ρ = mine recovery ratio

$$A = \frac{\pi R^{2}}{P} \qquad (7)$$

where A = subsidence area per ton of coal produced (gray area shown in Figure C2)
P = lifetime mine production

The overburden depth, h, is input per each NCRA coal region as described in Chapter 3. The continuous mine recovery ratio, ρ, is estimated by the model as described in Chapter 2. For both underground mine types, maximum subsidence depth is calculated:

$$S_{\max} = a \times m \qquad (8)$$

where S_{max} = maximum subsidence depth (shown in Figure C1)
m = mining height

As mentioned in Section 4, the complete range of longwall subsidence depth is shown in Figure C36, and longwall subsidence area is shown in Figure C38. Continuous mine subsidence depth is shown in Figure C37 and subsidence area is shown in Figure C39.

The results show the largest range of expected subsidence depth in the Rocky Mountains and Great Plains, but the largest range of subsidence area in eastern coal regions.

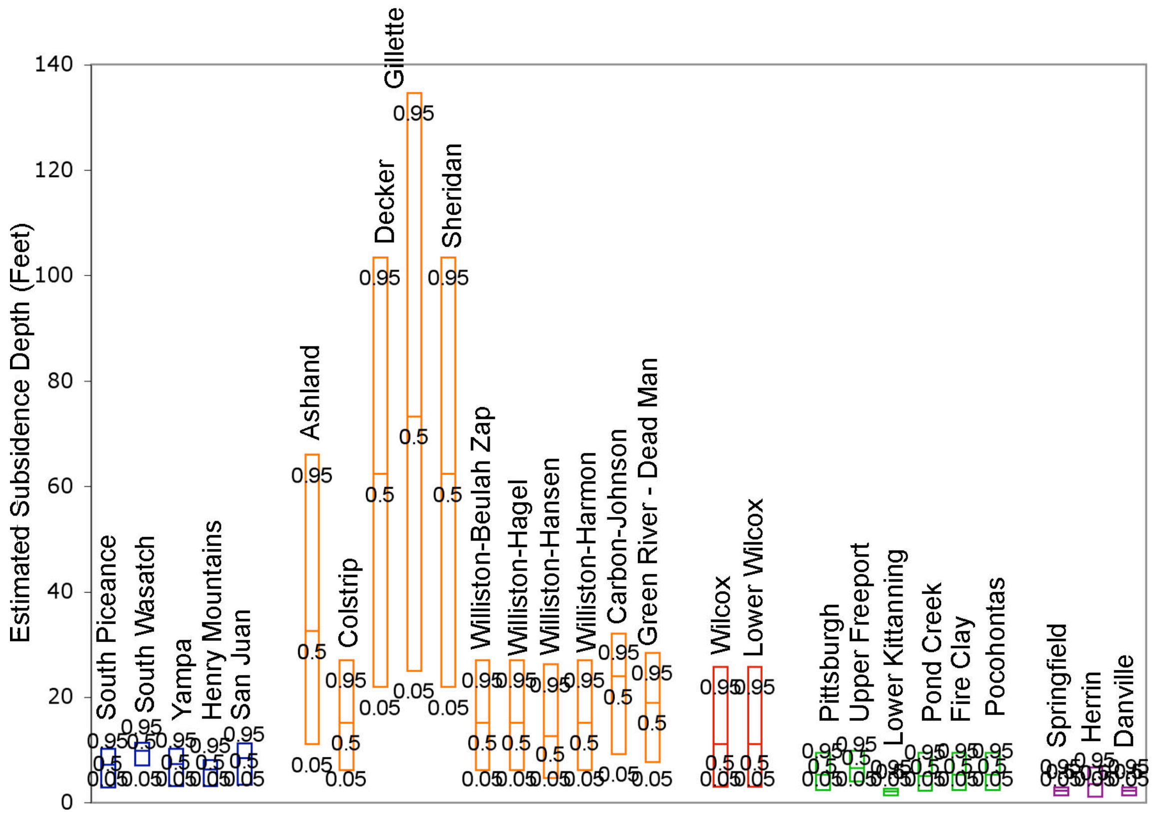

Figure C36 Median estimated maximum longwall subsidence depth, S_{max}. 5th, 50th, and 95th estimated percentiles are shown. Blue = Colorado Plateau, Orange = Rocky Mountains and Great Plains, Red = Gulf Coast, Green = Appalachia, and Purple = Illinois.

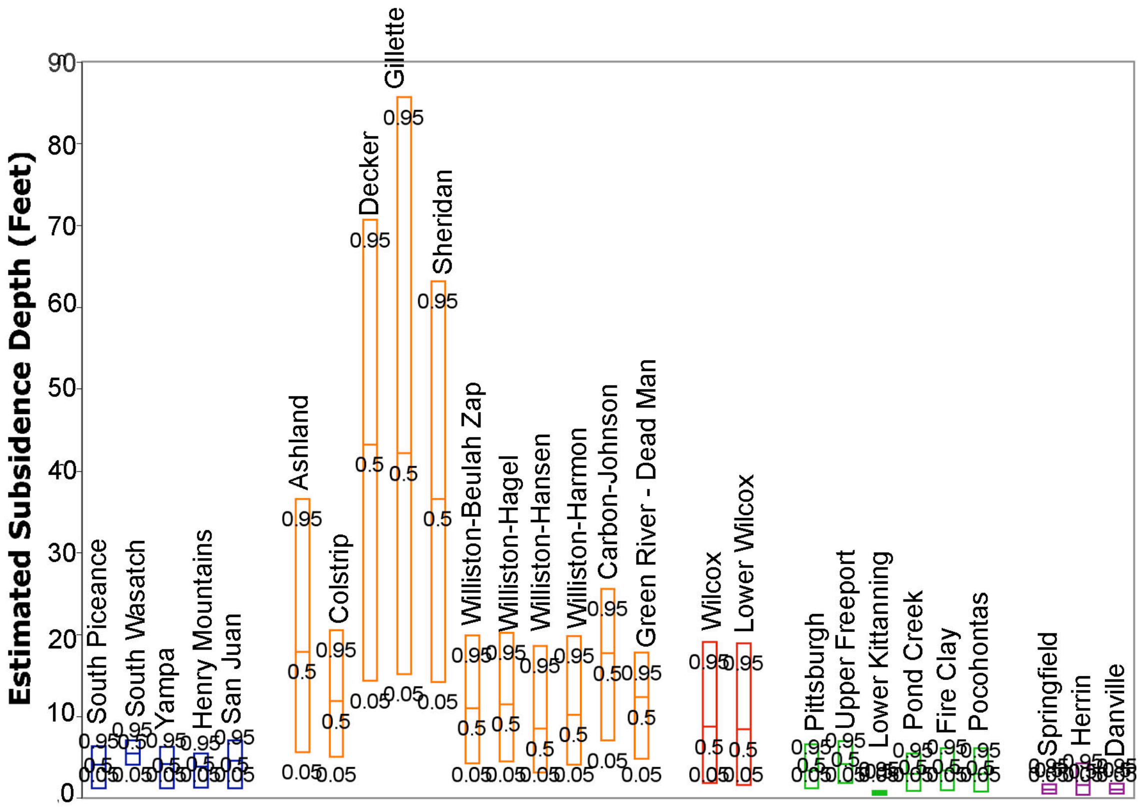

Figure C37 Estimated maximum continuous mine subsidence depth, S_{max}. 5th, 50th, and 95th percentile estimates are shown. Blue = Colorado Plateau, Orange = Rocky Mountains and Great Plains, Red = Gulf Coast, Green = Appalachia, Purple = Illinois.

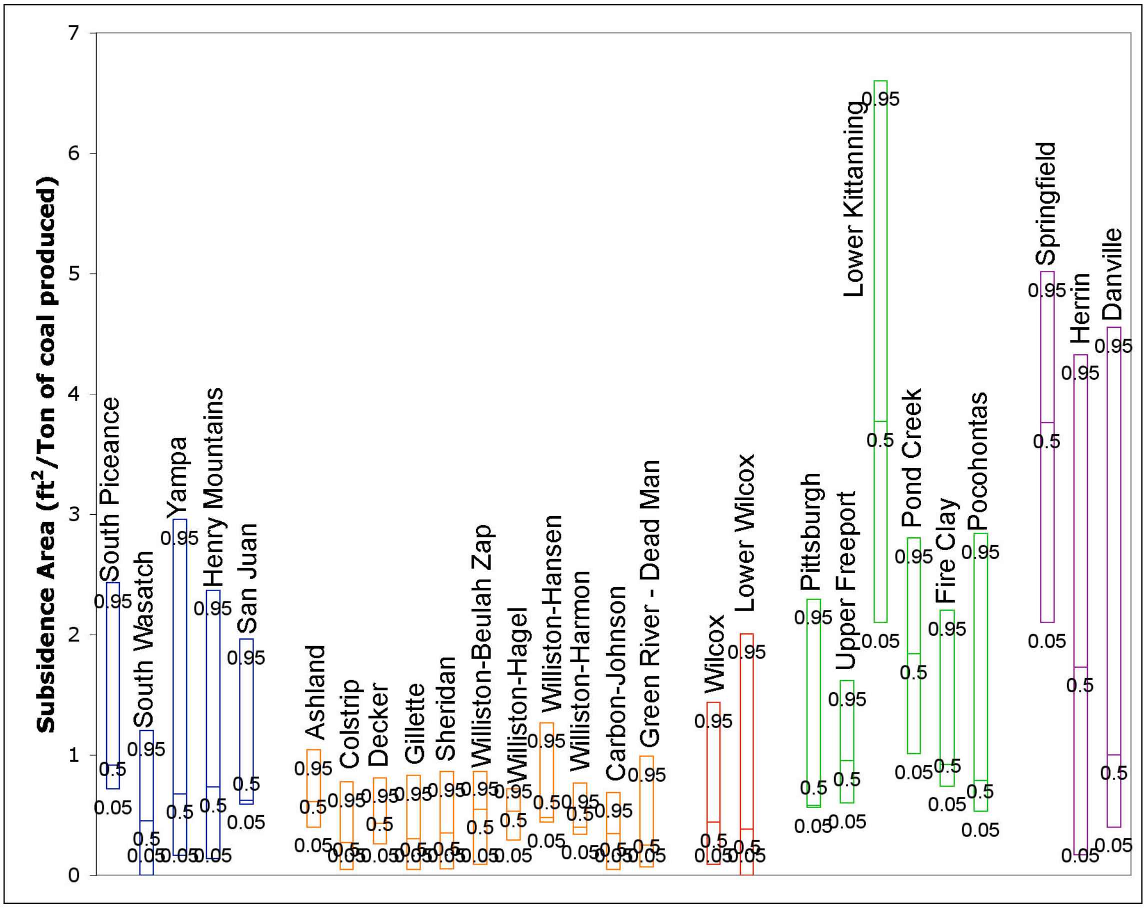

Figure C38. Expected subsidence area, A, from longwall mining per NCRA region and coalfield. The 5th, 50th, and 95th percentiles are shown. Blue = Colorado Plateau, Orange = Rocky Mountains and Great Plains, Red = Gulf Coast, Green = Appalachia, and Purple = Illinois.

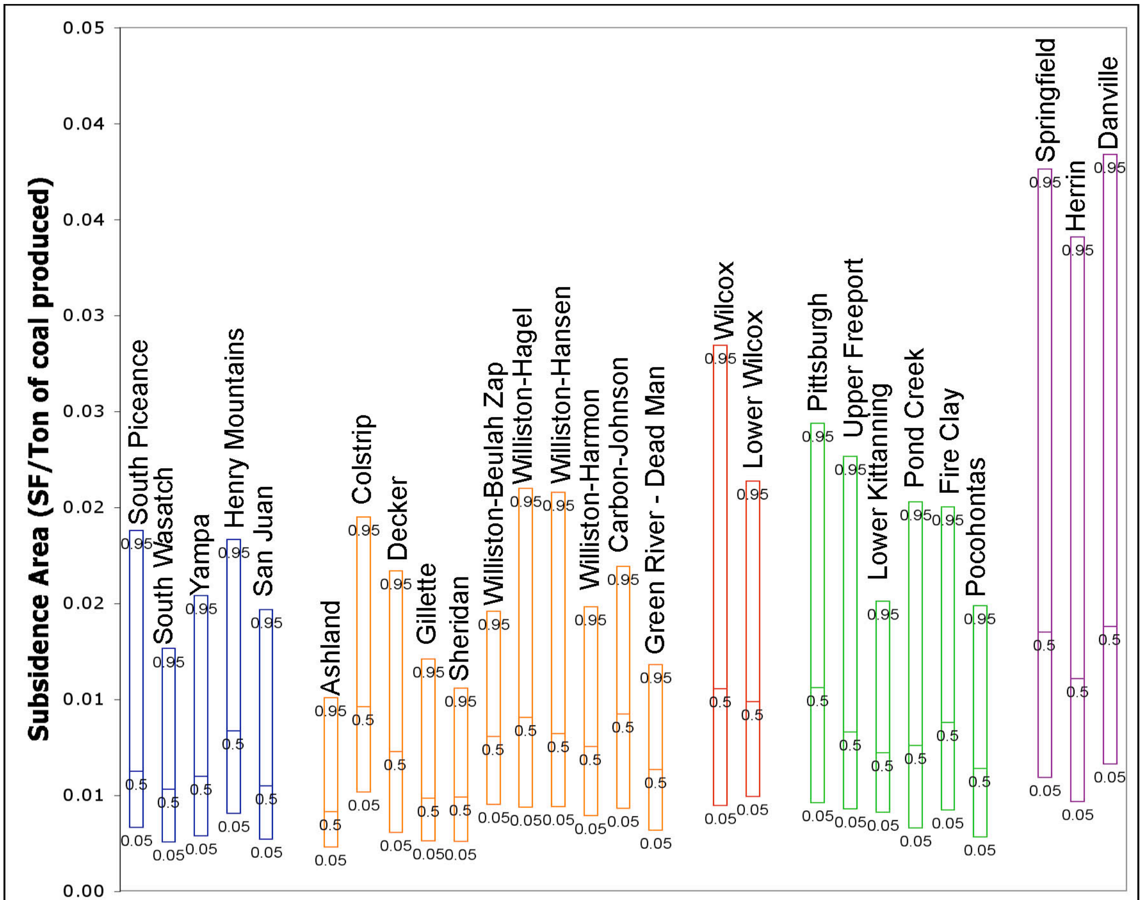

Figure C39. Estimated continuous mine subsidence, A, per NCRA region and coalbed. The 5th, 50th, and 95th percentiles are shown. Blue = Colorado Plateau, Orange = Rocky Mountains and Great Plains, Red = Gulf Coast, Green = Appalachia, Purple = Illinois.

As mentioned in Section 3.1.1.3, the complete range of 5th – 95th percentile costs are shown in Table C1- Table C85.

Table C79. Calculated Portland cement fracture zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	14	39	102	0	1	5
	South Wasatch	17	41	117	1	2	6
	Yampa	15	41	115	0	1	4
	Henry Mountains	14	37	98	0	2	6
	San Juan	17	40	112	0	2	4
Rocky Mountains and Great Plains	Ashland	34	97	547	1	5	21
	Colstrip	17	51	168	1	3	12
	Decker	47	153	742	4	16	68
	Gillette	59	200	1072	3	11	33
	Sheridan	43	178	739	2	10	33
	Williston-Beulah-Zap	14	43	158	1	4	21
	Williston-Hagel	16	38	145	2	6	22
	Williston-Hansen	16	39	136	1	4	15
	Williston-Harmon	15	39	179	1	4	14
	Carbon-Johnson	23	56	166	3	8	28
	Green River-Dead Man	21	52	172	1	4	15
Gulf Coast	Wilcox	13	33	145	1	4	17
	Lower Wilcox	14	35	121	1	4	18
Appalachia	Pittsburgh	13	32	97	1	2	7
	Upper Freeport	13	34	113	1	2	7
	Lower Kittanning	19	46	120	0	0	1
	Pond Creek	15	39	111	0	1	4
	Fire Clay	14	34	92	0	2	7
	Pocohontas	17	40	112	0	1	4
Illinois	Springfield	14	36	93	0	1	3
	Herrin	13	35	107	0	1	4
	Danville	14	34	101	0	1	3

Table C80. Calculated Portland Cement gob zone injection cost ($/ton of coal produced)

Region	Coalfield	Longwall 0.05	Longwall 0.5	Longwall 0.95	Continuous 0.05	Continuous 0.5	Continuous 0.95
Colorado Plateau	South Piceance	24	52	92	24	52	82
	South Wasatch	24	52	92	24	52	82
	Yampa	24	52	92	24	52	82
	Henry Mountains	24	52	92	24	52	82
	San Juan	24	52	92	24	52	82
Rocky Mountains and Great Plains	Ashland	24	52	92	24	52	82
	Colstrip	24	52	92	24	52	82
	Decker	24	52	92	24	52	82
	Gillette	24	52	92	24	52	82
	Sheridan	24	52	92	24	52	82
	Williston-Beulah-Zap	24	52	92	24	52	82
	Williston-Hagel	24	52	92	24	52	82
	Williston-Hansen	24	52	92	24	52	82
	Williston-Harmon	24	52	92	24	52	82
	Carbon-Johnson	24	52	92	24	52	82
	Green River-Dead Man	24	52	92	24	52	82
Gulf Coast	Wilcox	24	52	92	24	52	82
	Lower Wilcox	24	52	92	24	52	82
Appalachia	Pittsburgh	24	52	92	24	52	82
	Upper Freeport	24	52	92	24	52	82
	Lower Kittanning	24	52	92	24	52	82
	Pond Creek	24	52	92	24	52	82
	Fire Clay	24	52	92	24	52	82
	Pocohontas	24	52	92	24	52	82
Illinois	Springfield	24	52	92	24	52	82
	Herrin	24	52	92	24	52	82
	Danville	24	52	92	24	52	82

Table C81. Calculated rockfill gob zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	4	14	23	4	13	22
	South Wasatch	4	14	23	4	13	22
	Yampa	4	14	23	4	13	22
	Henry Mountains	4	14	23	4	13	22
	San Juan	4	14	23	4	13	22
Rocky Mountains and Great Plains	Ashland	4	14	23	4	13	22
	Colstrip	4	14	23	4	13	22
	Decker	4	14	23	4	13	22
	Gillette	4	14	23	4	13	22
	Sheridan	4	14	23	4	13	22
	Williston-Beulah-Zap	4	14	23	4	13	22
	Williston-Hagel	4	14	23	4	13	22
	Williston-Hansen	4	14	23	4	13	22
	Williston-Harmon	4	14	23	4	13	22
	Carbon-Johnson	4	14	23	4	13	22
	Green River-Dead Man	4	14	23	4	13	22
Gulf Coast	Wilcox	4	14	23	4	13	22
	Lower Wilcox	4	14	23	4	13	22
Appalachia	Pittsburgh	4	14	23	4	13	22
	Upper Freeport	4	14	23	4	13	22
	Lower Kittanning	4	14	23	4	13	23
	Pond Creek	4	14	23	4	13	22
	Fire Clay	4	14	23	4	13	22
	Pocohontas	4	14	23	4	13	22
Illinois	Springfield	4	14	23	4	13	23
	Herrin	4	14	23	4	13	23
	Danville	4	14	23	4	13	23

Table C82. Calculated limestone fracture zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	18	34	63	0	1	4
	South Wasatch	20	36	69	1	1	4
	Yampa	18	36	69	0	1	4
	Henry Mountains	18	32	61	1	1	4
	San Juan	20	34	65	0	1	4
Rocky Mountains and Great Plains	Ashland	36	88	331	1	4	15
	Colstrip	20	42	112	1	3	8
	Decker	49	137	438	4	14	45
	Gillette	57	198	633	3	10	30
	Sheridan	48	159	543	2	10	21
	Williston-Beulah-Zap	18	40	107	1	4	12
	Williston-Hagel	16	36	91	2	5	14
	Williston-Hansen	17	38	82	1	3	9
	Williston-Harmon	17	37	104	2	4	11
	Carbon-Johnson	22	44	119	2	7	22
	Green River-Dead Man	23	46	118	1	4	10
Gulf Coast	Wilcox	14	35	107	1	4	11
	Lower Wilcox	15	35	99	1	3	13
Appalachia	Pittsburgh	15	30	65	1	2	5
	Upper Freeport	17	33	64	1	2	5
	Lower Kittanning	23	46	70	0	0	1
	Pond Creek	17	34	66	0	1	3
	Fire Clay	16	32	57	0	1	5
	Pocohontas	19	34	67	0	1	3
Illinois	Springfield	16	34	62	0	1	2
	Herrin	18	30	63	0	1	3
	Danville	16	33	58	0	1	2

Table C83. Calculated limestone gob zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	36	43	54	36	43	52
	South Wasatch	36	43	54	36	43	52
	Yampa	36	43	54	36	43	52
	Henry Mountains	36	43	54	36	43	52
	San Juan	36	43	54	36	43	52
Rocky Mountains and Great Plains	Ashland	36	43	54	36	43	52
	Colstrip	36	43	54	36	43	52
	Decker	36	43	54	36	43	52
	Gillette	36	43	54	36	43	52
	Sheridan	36	43	54	36	43	52
	Williston-Beulah-Zap	36	43	54	36	43	52
	Williston-Hagel	36	43	54	36	43	52
	Williston-Hansen	36	43	54	36	43	52
	Williston-Harmon	36	43	54	36	43	52
	Carbon-Johnson	36	43	54	36	43	52
	Green River-Dead Man	36	43	54	36	43	52
Gulf Coast	Wilcox	36	43	54	36	43	52
	Lower Wilcox	36	43	54	36	43	52
Appalachia	Pittsburgh	36	43	54	37	43	52
	Upper Freeport	36	43	54	36	43	52
	Lower Kittanning	36	43	54	37	43	52
	Pond Creek	36	43	54	36	43	52
	Fire Clay	36	43	54	36	43	52
	Pocohontas	36	43	54	36	43	52
Illinois	Springfield	36	43	54	37	43	52
	Herrin	36	43	54	36	43	52
	Danville	36	43	54	37	43	52

Table C84. Calculated coal combustion residue fracture zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	4	7	10	4	7	10
	South Wasatch	4	7	10	4	7	10
	Yampa	4	7	10	4	7	10
	Henry Mountains	4	7	10	4	7	10
	San Juan	4	7	10	4	7	10
Rocky Mountains and Great Plains	Ashland	4	7	10	4	7	10
	Colstrip	4	7	10	4	7	10
	Decker	4	7	10	4	7	10
	Gillette	4	7	10	4	7	10
	Sheridan	4	7	10	4	7	10
	Williston-Beulah-Zap	4	7	10	4	7	10
	Williston-Hagel	4	7	10	4	7	10
	Williston-Hansen	4	7	10	4	7	10
	Williston-Harmon	4	7	10	4	7	10
	Carbon-Johnson	4	7	10	4	7	10
	Green River-Dead Man	4	7	10	4	7	10
Gulf Coast	Wilcox	4	7	10	4	7	10
	Lower Wilcox	4	7	10	4	7	10
Appalachia	Pittsburgh	4	7	10	4	7	10
	Upper Freeport	4	7	10	4	7	10
	Lower Kittanning	4	7	10	4	7	10
	Pond Creek	4	7	10	4	7	10
	Fire Clay	4	7	10	4	7	10
	Pocohontas	4	7	10	4	7	10
Illinois	Springfield	4	7	10	4	7	10
	Herrin	4	7	10	4	7	10
	Danville	4	7	10	4	7	10

Table C85. Calculated coal combustion residue fracture zone injection cost ($/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	2	5	11	0	0	1
	South Wasatch	3	5	13	0	0	1
	Yampa	3	5	13	0	0	1
	Henry Mountains	2	5	11	0	0	1
	San Juan	3	5	12	0	0	1
Rocky Mountains and Great Plains	Ashland	5	13	63	0	1	2
	Colstrip	3	7	19	0	0	2
	Decker	7	20	76	1	2	8
	Gillette	9	30	104	1	2	5
	Sheridan	6	24	101	0	1	4
	Williston-Beulah-Zap	2	6	18	0	1	2
	Williston-Hagel	2	5	16	0	1	2
	Williston-Hansen	2	5	16	0	1	2
	Williston-Harmon	2	5	19	0	1	2
	Carbon-Johnson	3	7	18	0	1	4
	Green River-Dead Man	3	7	20	0	1	2
Gulf Coast	Wilcox	2	4	18	0	1	2
	Lower Wilcox	2	5	14	0	1	3
Appalachia	Pittsburgh	2	4	11	0	0	1
	Upper Freeport	2	4	12	0	0	1
	Lower Kittanning	3	6	13	0	0	1
	Pond Creek	2	5	11	0	0	1
	Fire Clay	2	5	10	0	0	1
	Pocohontas	3	5	13	0	0	1
Illinois	Springfield	2	4	11	0	0	1
	Herrin	2	5	12	0	0	1
	Danville	2	4	11	0	0	1

Table C86. Calculated 5th, 50th and 95th percentile annual mine area (acres/year)

		Surface Pit Area			Longwall Surface Area			Continuous Surface Area		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	3	29	204	NA	NA	NA	NA	NA	NA
	Deserado	2	31	1032	NA	NA	NA	NA	NA	NA
	South Piceance	1	8	236	10	53	127	1	2	3
	South Wasatch	1	6	114	11	55	137	1	2	3
	Yampa	1	7	123	11	55	126	1	2	4
	Henry Mountains	2	18	225	10	53	127	1	2	3
Rocky Mountains and Great Plains	San Juan	1	7	198	11	55	136	1	2	3
	Ashland	1	10	239	3	27	91	0	1	2
	Colstrip	1	24	736	7	45	121	0	1	3
	Decker	4	91	2517	3	13	53	0	0	1
	Gillette	2	19	383	2	12	46	0	0	1
	Sheridan	2	17	191	2	13	55	0	0	1
	Williston-Beulah-Zap	9	65	906	9	53	126	0	1	2
	Williston-Hagel	17	254	4519	9	51	122	0	1	3
	Williston-Hansen	7	82	984	9	45	126	0	1	3
	Williston-Harmon	15	251	3485	9	49	125	0	1	3
	Hanna-Ferris 23, 25,31,50,65	1	7	69	NA	NA	NA	NA	NA	NA
	Hanna-Hanna 77,78,79,81	1	12	196	NA	NA	NA	NA	NA	NA
	Carbon-Johnson	1	10	289	8	48	121	0	1	2
	Green River-Dead Man	24	260	2629	11	50	117	0	1	2
Gulf Coast	Wilcox	14	288	2628	18	72	205	0	1	3
	Lower Wilcox	13	190	2669	21	75	240	1	1	3
Appalachia	Pittsburgh	2	51	1157	11	53	124	1	2	3
	Upper Freeport	3	33	507	10	53	128	1	2	3
	Lower Kittanning	0	3	9	9	51	121	1	2	4
	Pond Creek	1	10	138	10	53	124	1	2	3
	Fire Clay	2	22	569	10	54	126	1	2	4
	Pocohontas	1	6	122	10	54	125	1	2	3
Illinois	Springfield	1	27	602	10	51	118	1	2	4
	Herrin	2	23	320	10	52	121	1	2	4
	Danville	1	20	483	10	52	121	1	2	4

C.2 Backfill material description

Four fill materials are evaluated. These materials – Portland cement, cemented rockfill, limestone, and fly ash – are selections that address a range of available cost, groundwater acidification potential, and known structural performance. Portland cement and cemented rockfill are sturdy fill options. The unconfined compressive strength of cemented hydraulic fill and cemented rockfill are 116 psi and 290 psi, respectively. The structural strengths of limestone and coal combustion residues are not known. Cemented hydraulic fill is most prevalent in mine backfill operations but is expensive and carbon intensive. Cemented rockfill accounts for 6 percent of fill used in mineral mines worldwide [5], and is less expensive than Portland cement. Limestone costs almost as much as Portland cement, but can be injected into the fracture zone without acidifying groundwater. Because it is an alkaline material that is typically used to balance mine acidified waters [6, 7], it is a suitable fill candidate. Coal combustion residues, or byproducts, such as fly ash are also alkaline and may be suitable fill. Current coal combustion residue costs are comparable to cemented rockfill costs, but its availability is uncertain [8].

The long term success of coal mine subsidence mitigation, by backfilling, is uncertain. There are no studies that can affirm the long term successful subsidence reduction. Most reports evaluating its effect on groundwater resources point out that more research is needed to better understand affects on flow and water quality[9] [8, 10]. As previously mentioned, The long term effects of limestone, which should be the most neutralizing of fills, is also uncertain. It is believed that limestone can neutralize acid mine formation for 20 – 25 years [11]. Evaluations of limestone drains to treat acid mine drainage have lasted no longer than 10 years [12, 13], so there is no empirical confirmation that limestone addition can reduce acid formation over the projected lifetime of the material. Similarly, coal combustion residue long term neutrality in underground environments is uncertain [8].

C.3 Indirect CO_2 Emissions from Portland Cement Backfill

As discussed in Section 3.1.1.3, Portland cement manufacturing emits a significant amount of CO2 emissions. Portland cement production emits 1,800 – 2,100 lb CO_2 per ton of cement [14], or about 1 ton CO_2 per ton of cement. Assuming Portland cement density is 0.02 ton/ft3 [15]. CO_2 emissions from manufacturing the Portland cement to backfill longwalls and continuous mines are shown in Table C9 and Table C10. It is assumed that 100 percent Portland cement will be used to fill the mines.

Table C87. CO_2 Emissions Associated with Fracture Zone Portland Cement Fill per NCRA region (Million tons CO_2). Estimate assumes 100% Portland cement fill into the fracture zone. Estimates are for single mines in each NCRA region.

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	9	21	33	0	0	1
	South Wasatch	21	30	41	0	0	1
	Yampa	9	23	38	0	0	1
	Henry Mountains	9	18	27	0	0	0
Rocky Mountains and Great Plains	San Juan	11	25	39	0	0	1
	Ashland	37	108	220	0	1	3
	Colstrip	19	41	77	0	1	2
	Decker	46	148	294	1	3	8
	Gillette	79	218	433	1	2	6
	Sheridan	66	184	328	1	2	4
	Williston-Beulah-Zap	15	37	78	0	1	2
	Williston-Hagel	15	33	68	0	1	3
	Williston-Hansen	10	31	74	0	1	2
	Williston-Harmon	15	38	72	0	1	2
	Carbon-Johnson	21	54	78	1	2	4
	Green River-Dead Man	20	49	91	0	1	2
Gulf Coast	Wilcox	8	27	60	0	1	3
	Lower Wilcox	7	27	69	0	1	2
Appalachia	Pittsburgh	6	14	25	0	0	1
	Upper Freeport	11	17	28	0	0	1
	Lower Kittanning	5	7	11	0	0	0
	Pond Creek	6	16	27	0	0	0
	Fire Clay	6	15	29	0	0	1
	Pocohontas	7	16	31	0	0	0
Illinois	Springfield	3	6	10	0	0	0
	Herrin	3	10	18	0	0	0
	Danville	4	6	9	0	0	0

Table C88. CO_2 Emissions Associated with Gob Zone Portland Cement Fill per NCRA region (Million tons CO_2). Estimate assumes 100% Portland cement fill into the fracture zone. Estimates are for single mines in each NCRA region.

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	8	25	56	2	7	11
	South Wasatch	19	34	65	5	9	14
	Yampa	5	26	60	3	7	13
	Henry Mountains	8	22	45	3	6	11
Rocky Mountains and Great Plains	San Juan	6	28	58	3	8	12
	Ashland	21	39	76	6	10	16
	Colstrip	11	37	73	5	9	16
	Decker	24	40	76	6	10	16
	Gillette	26	40	76	6	10	15
	Sheridan	26	40	76	6	10	16
	Williston-Beulah-Zap	13	37	74	5	10	15
	Williston-Hagel	11	38	73	5	10	14
	Williston-Hansen	9	37	74	4	9	15
	Williston-Harmon	12	38	74	5	10	15
	Carbon-Johnson	16	40	74	6	10	15
	Green River-Dead Man	17	38	74	5	10	15
Gulf Coast	Wilcox	6	33	71	3	8	15
	Lower Wilcox	5	33	73	3	8	13
Appalachia	Pittsburgh	5	21	47	3	6	11
	Upper Freeport	11	25	46	3	7	10
	Lower Kittanning	3	8	15	1	3	4
	Pond Creek	5	18	45	2	6	11
	Fire Clay	7	19	52	2	6	10
	Pocohontas	4	21	46	2	6	10
Illinois	Springfield	4	8	16	1	3	5
	Herrin	1	12	36	1	4	8
	Danville	3	8	16	1	3	5

C.4 Appalachian mountain top removal and valley fill

Appalachian surface mining is contentious for several reasons. Spoil storage is one of the controversies. When overburden is removed, the soil and rock is broken and expands; it is considered "spoil" if it can't be replaced in the pit. It may be too difficult to replace in the pit, or it may have expanded so much that it can't be compressed into the pit. Either way, spoil storage in Appalachia is controversial because there is not much space to store it in the mountainous terrain. It is usually pushed into adjacent valleys, earning Appalachian mountain surface mining operations the nickname of "mountain top removal and valley fill". The result is a complete change in topography, wherein mountaintops are relocated to valleys, transforming mountains to plateaus. Furthermore, when pushed into the valleys, the spoil often fills streams. The Surface Mining Control and

Reclamation Act of 1977 (SMCRA) allows variances, or exceptions, to approximate original contour restoration and stream filling regulations. Over the last ten years, a ruling by U.S. District Judge Charles J. Haden II determined that depositing spoil in stream fill violated the Clean Water Act, and a lawsuit initiated by a West Virginia community found that the SMCRA was not enforced properly [16]. The stream fill ruling was overturned in 2001 [17].

C.5 Land use changes

There are some challenges in comparing pre- and post-mining land use. Often, categories do not match. For example, see data from an analysis performed for EPA in Table C89. If "core hardwood forest", "diverse/mesophytic hardwood forest", "hardwood/conifer forest", "oak dominant forest", and "mountain hardwood forest" are to be considered mature forestland, forest accounted for 92% of land use before mining. After mining, 36% of land is forest, and this category is shared with "wildlife". By contrast, less than 1% of land is "pasture/grassland" before mining, but after mining 24% of land is devoted to pasture of some kind – "hay/pasture" is 20% of land use and "animal grazing/pasture" is 4%.

Table C89. Pre- and post-mining land use in West Virginia sample of 65,354 acres [18]

Pre-mining land use category	Percent	Post-mining land use category	Percent
Shrubland	0.97	Forest/wildlife	36
Woodland	0.32	Commercial woodland	5
Major powerlines	0.32	Woodland	27
Light intensity urban	0.32	Hay/pasture	20
Pasture/grassland	0.97	Animal grazing/pasture	4
Barren land – mining, construction	4.85	Combined (multiple land uses)	7
Core hardwood forest	16.50	Residential/housing	<1
Diverse/mesophytic hardwood forest	0.97	Public service/public use	<1
Hardwood/conifer forest	0.97		
Oak dominant forest	9.39		
Mountain hardwood forest	5.18		

A more extensive analysis of land use trends by the United States Geological Survey (USGS) [19] also shows similar change from forested land to mining land, and ultimately to pasture. It may be argued that “grassland/shrubland” ultimately transforms to “forest”, but the mining companies are not directly restoring land to forest. There is no “grassland/shrubland” being transformed into “mining” land. “Forest” is transformed to “mining” but when “mining” land is typically converted to another land use. As shown in Table C90, except for Central Appalachia, all mined Appalachian regions have more mining land transformed to “grassland/shrubland” than to “forest” and in North Central Appalachia there “mining” land has not changed into any other land use from 1973 – 2000.

Table C90. Land use class changes in mined Appalachian regions, 1973 – 2000. [19]

Appalachian region	From class	To class[a]	Km^2	Percent change
North Central	Forest	Mechanically disturbed	1055	39
	Mechanically disturbed	Forest	928	34
	Forest	Mining	174	6
	Non-mechanically disturbed	Forest	110	4
	Forest	Non-mechanically disturbed	108	4
	Other classes	Other classes	355	13
Southwestern	Forest	Mechanically disturbed	2626	33
	Mechanically disturbed	Forest	1698	21
	Grassland/shrubland	Forest	750	9
	Mining	Grassland/shrubland	671	8
	Forest	Mining	610	8
	Other classes	Other classes	1675	21
Central	Forest	Mining	2620	34
	Mining	Forest	1094	14
	Mining	Grassland/shrubland	711	9
	Forest	Mechanically disturbed	632	8
	Forest	Grassland/shrubland	612	8
	Grassland/shrubland	Forest	555	7
	Mechanically disturbed	Forest	392	5
	Other classes	Other classes	1054	14
Western Allegheny Plateau	Mining	Grassland/shrubland	12345	18
	Grassland/shrubland	Forest	993	14
	Forest	Mining	835	12
	Forest	Mechanically disturbed	580	8
	Forest	Grassland/shrubland	540	8
	Forest	Agriculture	391	6
	Agriculture	Forest	381	5
	Other classes	Other classes	2043	29

[a]USGS land class definitions: *Mechanically disturbed* = land in an altered and often unvegetated state that, due to disturbances by mechanical means, is in transition from one cover type to another. Mechanical disturbances include forest clear-cutting, earthmoving, scraping, chaining, reservoir drawdown, and other similar humand-induced changes; *Mining* = areas with extractive mining activities that have a significant

surface expression. This includes (to the extent that these features can be detected) mining buildings, quarry pits, overburden, leach, evaporative, tailings, or other related components; *Forest* – tree-covered land where the tree cover density is greater than 10 percent. Note that cleared forest land (i.e., clear-cuts) is mapped according to current cover (e.g., mechanically disturbed or grassland/shrubland); *Grassland/shrubland* - land predomeinantely covered ith grasses, forbs, r shrubs. The vegetated cover must comprise at least 10 percent of the area. *Agriculture* – land in either a vegetated or an unvegetated state used for the production of food and fiber. This includes cultivated and uncultivated croplands, hay lands, pasture, orchards, vineyards, and confined livestock operations. Note that forest plantations are considered forests regardless of the use of the wood products. *Non-mechanically disturbed* – land in an altered and often unvegetated state that, due to disturbances by non-mechanical means, is in transition from one cover type to another. Non-mechanical disturbances are caused by fire, wind, floods, animals, and other similar phenomena. *Other classes* – not defined.

Transformation of forested land to pasture is not unique to Appalachia. It is also happening in the Illinois basin. Evaluation of coal mine reclamation records showed that exotic grass species that could grow quickly and tolerate the now acidic soil conditions were being planted, with little distribution of native plants and grasses. Reclamation regulation is credited with the switch towards grass seeding instead of tree planting [20]:

> Reclamation laws inadvertently encouraged the switch from forest to grassland. In [Indiana, Illinois, and Kentucky], progressive expansion of grading requirements increased the cost of reclamation so that inexpensive grassland plantings became more economically attractive. At the same time, grading caused soil compaction that made it more difficult to establish trees and that favored shallow-rooted herbaceous species.

Similar land use analysis could not be completed, as there is no detailed evaluation of land class changes. The USGS land cover study is currently expanding to include the western U.S.

C.6 Surface land damage costs

Estimated surface land damage per each NCRA region and coalfield is shown in Table C91.

Table C91. Surface mine land impact per NCRA coal region (ft^2/ton coal produced)

Region	Coalfield	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	7.0E-03	6.7E-03	9.7E-03
	Deserado	0.7	0.4	0.4
	South Piceance	4.5	2.7	2.0
	South Wasatch	1.7	2.8	2.1
	Yampa	3.2	3.1	2.3
	Henry Mountains	4.9	3.5	3.8
	San Juan	2.5	2.4	2.6
Rocky Mountains and Great Plains	Ashland	1.0	0.8	0.5
	Colstrip	1.8	1.4	1.1
	Decker	0.7	0.3	0.2
	Gillette	0.4	0.3	0.2
	Sheridan	0.4	0.3	0.4
	Williston-Beulah-Zap	1.9	1.2	1.8
	Williston-Hagel	2.0	1.1	0.9
	Williston-Hansen	3.1	1.7	1.3
	Williston-Harmon	2.0	1.3	1.6
	Hanna-Ferris 23, 25,31,50,65	0.1	0.0	0.0
	Hanna-Hanna 77,78,79,81	0.2	0.2	0.1
	Carbon-Johnson	1.0	0.9	0.7
	Green River-Dead Man	1.6	1.1	1.0
Gulf Coast	Wilcox	2.3	2.0	1.7
	Lower Wilcox	2.7	1.8	1.8
Appalachia	Pittsburgh	2.5	3.8	5.2
	Upper Freeport	3.4	3.0	1.9
	Lower Kittanning	8.4	9.5	11.3
	Pond Creek	5.0	4.9	4.6
	Fire Clay	3.9	3.7	3.9
	Pocohontas	3.8	4.4	1.5
Illinois	Springfield	8.9	9.1	7.8
	Herrin	6.1	6.1	3.9
	Danville	13.4	7.2	7.4

As discussed in Section 3.2.1.1, revegetation and reforestation costs are the cost to repair damage from surface mine pits (Table C14).

Table C92. Calculated revegetation and reforestation cost ($/ton of coal produced)

Region	Coalfield	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0.0	0.0	0.0
	Deserado	0.1	0.1	0.2
	South Piceance	0.2	0.3	0.7
	South Wasatch	0.2	0.2	0.3
	Yampa	0.2	0.3	0.6
	Henry Mountains	0.2	0.3	0.6
	San Juan	0.2	0.2	0.5
Rocky Mountains and Great Plains	Ashland	0.0	0.1	0.2
	Colstrip	0.1	0.1	0.3
	Decker	0.0	0.0	0.1
	Gillette	0.0	0.0	0.1
	Sheridan	0.0	0.0	0.1
	Williston-Beulah-Zap	0.1	0.1	0.3
	Williston-Hagel	0.1	0.1	0.3
	Williston-Hansen	0.1	0.2	0.4
	Williston-Harmon	0.1	0.1	0.3
	Hanna-Ferris 23, 25,31,50,65	0.0	0.0	0.1
	Hanna-Hanna 77,78,79,81	0.0	0.0	0.0
	Carbon-Johnson	0.1	0.1	0.2
	Green River-Dead Man	0.1	0.1	0.3
Gulf Coast	Wilcox	0.1	0.2	0.6
	Lower Wilcox	0.1	0.2	0.6
Appalachia	Pittsburgh	0.2	0.4	0.8
	Upper Freeport	0.2	0.3	0.5
	Lower Kittanning	0.7	0.9	1.4
	Pond Creek	0.2	0.4	0.9
	Fire Clay	0.2	0.3	0.8
	Pocohontas	0.2	0.4	0.8
Illinois	Springfield	0.6	0.8	1.3
	Herrin	0.3	0.5	1.7
	Danville	0.6	0.9	1.4

C.4 Robotic underground mining costs

At this time, human operators are still needed to oversee the machines. The longwall automation technology is being commercialized in a joint agreement with the Joy mining equipment company. Sensing technologies above and below the shearer decrease dilution that results from cutting into the ceiling and floor. On the left-to-right pass, it senses the lay of the seam. On the right-to-left pass, it cuts according to the profile sensed in the previous cut. Unmanned continuous miners are developed, and await commercialization [21-23].

To calculate likely cost of autonomous mining, the best capital cost estimate for autonomous longwall shearers and continuous miners was determined according to the additional cost of guiding technology. Additional manufacturer cost is the best estimate of cost. However, once these technologies are commercialized the manufacturer will probably charge a price that includes marketing, research and development, and sales markup. The additional cost to add U.S. tank driving technology to a longwall shearer is 100,000 AUD, which is worth $115,000 assuming 0.87 AUD to the U.S. dollar [24]. As there are no recorded instances of robotic continuous miners being used, and the technology has not been commercialized, the additional cost of automation was estimated by comparing conventional and unmanned ground vehicle prices. The typical cost of an army truck is $50,000 - $150,000 [25]. The cost of an unmanned ground vehicle ranges from $600,000 - $800,000 [26, 27]. The revised capital costs for a longwall shearer and continuous miner, based on the baseline capital costs in Chapter 2, are $1.82 million - $2.62 million dollars and $1.68 – 4.00 million dollars, respectively. The operating costs are assumed to remain the same, and it is also assumed that the same number of miners will work at the mine, albeit in a different function – likely remote control of the machines from the surface with occasional underground maintenance. As a conservative estimate, it is assumed longwall production rates increase by 30%, and continuous mining productivity increases by 10%. The revised mining costs to underground mine using autonomous equipment is shown in Table C14. Comparing the median estimated costs to the median baseline underground mining costs reported in Chapter 2, using autonomous longwalls would reduce coal mining costs by an average 10%. Autonomous continuous miner units would not result in a significant decrease in mining costs.

Table C93. Calculated autonomous underground mining cost by mine type and coalfield ($/Ton)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills						
	Deserado						
	South Piceance	18	24	71	23	33	63
	South Wasatch	15	20	32	20	28	39
	Yampa	18	24	76	22	33	63
	Henry Mountains	19	27	54	25	35	61
	San Juan	16	22	56	22	30	54
Rocky Mountains and Great Plains	Ashland	14	17	24	19	25	32
	Colstrip	14	18	42	19	26	36
	Decker	14	17	24	19	25	32
	Gillette	14	16	23	19	25	33
	Sheridan	14	16	24	19	25	32
	Williston-Beulah-Zap	14	18	43	19	26	37
	Williston-Hagel	14	18	38	19	26	39
	Williston-Hansen	15	19	54	20	27	44
	Williston-Harmon	14	18	40	20	26	37
	Hanna-Ferris 23, 25,31,50,65						
	Hanna-Hanna 77,78,79,81						
	Carbon-Johnson	14	17	33	19	25	34
	Green River-Dead Man	14	17	36	19	25	33
Gulf Coast	Wilcox	15	19	77	20	27	64
	Lower Wilcox	15	20	70	20	28	58
Appalachia	Pittsburgh	18	30	115	24	38	89
	Upper Freeport	18	26	45	24	33	48
	Lower Kittanning	47	65	145	54	75	119
	Pond Creek	19	31	80	25	40	79
	Fire Clay	19	31	86	26	40	72
	Pocohontas	20	29	97	24	38	87
Illinois	Springfield	45	62	117	48	67	122
	Herrin	24	43	250	29	53	164
	Danville	43	65	126	46	73	126

C.5 Erosion estimation methods

U.S. government agencies refer to the Revised Universal Soil Loss Equation (RUSLE) [28-30] (equation 9) to calculate soil erosion rates, and the Wind Erosion Equation (WEQ) (equation 10) to calculate wind erosion rates [28]. These equations are dependent on site specific qualities, and are calculated:

$$A = RKLSCP \tag{9}$$

Where: A = average annual soil loss (tons/acre/year)
R = rainfall/runoff erosivity
K = soil erodibility
LS = hillslope length and steepness
C = cover management
P = support practice to mitigate erosion

$$E = f(IKCLV) \tag{10}$$

Where: E = estimation of annual soil loss (tons/acre)
f = functional nonlinear relationship
I = soil erodibility index
K = ridge roughness factor
C = climactic factor, as compared to Garden City, KS
L = unsheltered distance across and erodible field, along the prevailing wind direction
V = vegetative cover factor

The input variables to these equations are deemed site specific, and there is no broad national assessment. There are limited measurements available for the RUSLE, and few for the WEQ. If one knows the soil quality, slope gradient and length, the EPA provides K, LS, and P values to be input to the RUSLE [31] The OSM provides estimated lifetimes for support practices on mined lands [29]. The WEQ can be estimated following the guidance provided in the EPA AP-42 Handbook, which provides calculations for coal storage piles and industrial exposed areas. However, to apply this method, the number of wind disturbances per year must be known [32].

Total erosion is estimated, based on simulated mine area. For surface and underground mines, it is the total surface pit area and permitted area for an underground mine, respectively. The total soil erosion, and soil erosion per ton of coal produced for simulated mines per each NCRA region are calculated:

$$Er_{Total} = \frac{R_i LA}{P} \tag{11}$$

Where: Er_{Total} = total erosion loss for mine type (tons of soil)
R_i = RUSLE erosion factor for region i (Table C94)
LA = model simulated land disturbance rate (acres/year)

$$Ep_j = \frac{Er_{Total,j}}{P_j} \quad (12)$$

Where: Ep_j = erosion rate per ton of coal produced (tons/ton coal)
P_j = model simulatedtotal mine lifetime production for mine type j

C.6 Water induced erosion rates

A literature search revealed that there are no estimation factors for water erosion on mine sites, and the only available wind erosion factors were developed for western surface mines [33]. The best analog to assess water erosion at a mine site is construction site erosion. Construction is like a mine operation, as it also requires land clearing, regarding, large equipment, and leaving large swathes of land denuded for long periods of time.

For their guidance on Final Effluent Guidelines for Construction and Development EPA looked at construction sites sized from 0.5 – 200 acres, and included single family residences, multifamily residential, commercial and industrial construction. For large construction sites, the EPA identified sediment ponds as the best management practice. Rusle factors K, R, LS, C, P were all determined for Denver CO, Salt Lake City UT, Austin TX, Atlanta GA, Charleston SC, Jacksonville FL, Miami FL, Albany NY, Pittsburgh PA, St. Paul MN, Houston TX, Kansas City (unidentified state), Rapid City SD, Boise ID, Eureka CA, San Francisco CA, Seattle WA, Highland WA, and Mt. Hood WA [34]. The cities of interest, that fall within the NCRA coal producing regions are Denver and Pittsburgh. Unfortunately, there is no RUSLE study in the Illinois Basin or Gulf Coast coal regions. The closest cities to the Illinois Basin are St. Paul and Kansas City. The closest cities to the Gulf Coast are Atlanta, Miami and Jacksonville. It is assumed that St. Paul and Kansas City erosion rates can be representative of the Illinois Basin. However, due to lack of additional information for the Gulf Coast region, no erosion rates are applied to this coal producing region. The erosion rates were determined for 100 – 200 feet long, 3 – 12% slopes. A mix of sand, loamy sand, and sandy loam soils were examined. It is assumed that the construction site erosion factors developed by EPA are applicable to minesites because they have similar exposed areas. A NIOSH study evaluated typical surface mine pit design and slope in response to accidents during mining, that resulted from eroded land collapsing on miners in the Appalachian Basin [35]. The slope lengths were 100 – 350 feet for mountain top removal and combined mountain top removal and contour mines, at 10º - 15º off the vertical. These grades are steeper than those at the EPA simulated construction sites, but the EPA also assumed sandy to sandy loam soils which are more erosive than the clay, shale and sand combination found throughout the country. It is assumed that until mine specific erosion factors are available, that the additional erosivity of the EPA simulated soils makes up for the milder slopes.

The calculated Denver, Pittsburgh, Kansas City, and St. Paul erosion rates, used to determine water erosion for western and eastern coal mines respectively, are shown in Table C16. As can be seen in Table C16, erosion rates vary according to soil type, slope length and grade. In order to use these erosion rates, and to represent all hypothetical mine slope conditions, uniform distribution of these rates per applicable coal mine basin is assumed. The erosion rates in Table C16 are applied National Coal Resource Assessment coalfields such that the Colorado Plateau and Northern Rocky Mountains and Great Plains are represented by Denver, Northern and Central Appalachian Basin by Pittsburgh, and the Illinois Basin by Kansas City and St. Paul. Again, no assumptions about erosion rates for the Gulf Coast were made.

Table C94. RUSLE calculated erosion rates (tons/acre/year) [34]

		3% Slope, 200 feet length			7% Slope, 140 feet length			12% Slope, 100 feet length			Uniform Distribution input to model
NCRA Region	EPA RUSLE Simulation City	Sand	Sandy Loam	Loam	Sand	Sandy Loam	Loam	Sand	Sandy Loam	Loam	
Colorado Plateau Northern Rocky Mountains and Great Plains	Denver	0.73	3.96	5.58	1.60	8.66	12.19	2.71	14.63	20.59	0.73 – 20.59
Central and Northern Appalachian Basin	Pittsburgh	28.53	16.05	22.58	62.35	35.07	49.36	105.28	59.22	83.35	16.05 – 105.28
Illinois Basin	Kansas City	36.15	20.33	28.62	79.00	44.44	62.54	133.40	75.04	105.61	11.83 – 133.40
	St. Paul	21.03	11.83	16.65	45.97	25.86	36.39	77.62	43.66	61.45	

The erosion rates shown in Table C16 are used to calculate expected erosion, shown in Tables C17 and C18. As discussed in section 6.3, complete estimated erosion avoidance costs are shown in Tables C19 and C20.

Table C95. Calculated 5th, 50th, 95th percentile water erosion per NCRA region (tons of soil per million tons of coal produced)

		Longwall			Continuous			Surface		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	NA	NA	NA	NA	NA	NA	0	0	1
	Deserado	NA	NA	NA	NA	NA	NA	3	17	36
	South Piceance	1	4	20	0	1	2	6	32	111
	South Wasatch	1	3	14	0	0	1	4	24	51
	Yampa	1	5	18	0	1	2	5	33	92
	Henry Mountains	1	4	24	0	1	2	6	39	87
Rocky Mountains and Great Plains	San Juan	0	4	13	0	0	2	5	28	76
	Ashland	0	1	7	0	0	0	1	7	24
	Colstrip	0	2	10	0	0	1	2	14	52
	Decker	0	1	3	0	0	0	1	4	12
	Gillette	0	0	3	0	0	0	0	3	11
	Sheridan	0	1	3	0	0	0	1	3	11
	Williston-Beulah-Zap	0	2	11	0	0	1	2	15	50
	Williston-Hagel	0	2	11	0	0	1	2	14	48
	Williston-Hansen	0	3	15	0	0	1	3	17	75
	Williston-Harmon	0	2	10	0	0	1	3	15	49
	Hanna-Ferris 23, 25,31,50,65	NA	NA	NA	NA	NA	NA	1	5	8
	Hanna-Hanna 77,78,79,81	NA	NA	NA	NA	NA	NA	0	2	4
	Carbon-Johnson	0	2	7	0	0	1	2	10	27
	Green River-Dead Man	0	2	7	0	0	1	2	12	43
Gulf Coast	Wilcox	0	0	0	0	0	0	56	174	761
	Lower Wilcox	0	0	0	0	0	0	48	173	804
Appalachia	Pittsburgh	8	29	154	1	4	14	69	234	635
	Upper Freeport	8	23	90	1	3	9	48	182	438
	Lower Kittanning	17	66	319	3	10	26	225	649	1393
	Pond Creek	10	32	147	1	4	15	74	245	679
	Fire Clay	7	30	133	1	4	16	72	234	584
	Pocohontas	7	30	161	1	4	16	82	227	624
Illinois	Springfield	19	77	283	3	11	25	178	678	1501
	Herrin	12	49	204	2	7	25	104	388	1394
	Danville	14	78	374	3	12	29	3	4	6

Table C96. Calculated 5th, 50th, and 95th percentile wind erosion loss per NCRA region (tons of soil per million tons of coal produced)

Region	Coalfield	Longwall 0.05	Longwall 0.5	Longwall 0.95	Continuous 0.05	Continuous 0.5	Continuous 0.95	Surface 0.05	Surface 0.5	Surface 0.95
Colorado Plateau	Danforth Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Deserado	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.6	0.9
	South Piceance	0.1	0.1	0.7	0.0	0.0	0.1	0.8	1.2	2.9
	South Wasatch	0.1	0.1	0.4	0.0	0.0	0.0	0.7	0.9	1.2
	Yampa	0.1	0.2	0.5	0.0	0.0	0.0	0.8	1.1	2.5
	Henry Mountains	0.1	0.2	0.6	0.0	0.0	0.1	1.0	1.4	2.9
Rocky Mountains and Great Plains	San Juan	0.1	0.1	0.4	0.0	0.0	0.0	0.7	1.0	2.3
	Ashland	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.3	0.8
	Colstrip	0.0	0.1	0.3	0.0	0.0	0.0	0.3	0.5	1.5
	Decker	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.4
	Gillette	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.4
	Sheridan	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.4
	Williston-Beulah-Zap	0.0	0.1	0.3	0.0	0.0	0.0	0.3	0.5	1.4
	Williston-Hagel	0.0	0.1	0.3	0.0	0.0	0.0	0.3	0.5	1.5
	Williston-Hansen	0.0	0.1	0.4	0.0	0.0	0.0	0.3	0.7	1.9
	Williston-Harmon	0.0	0.1	0.3	0.0	0.0	0.0	0.3	0.6	1.5
	Hanna-Ferris 23, 25,31,50,65	0.0	0.1	0.3	0.0	0.0	0.0	0.1	0.2	0.2
	Hanna-Hanna 77,78,79,81	0.0	0.1	0.2	0.0	0.0	0.0	0.1	0.1	0.1
	Carbon-Johnson	0.0	0.1	0.6	0.0	0.0	0.0	0.2	0.4	0.9
	Green River-Dead Man	0.0	0.1	0.4	0.0	0.0	0.1	0.3	0.4	1.1
Gulf Coast	Wilcox	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.7	2.8
	Lower Wilcox	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.8	3.0
Appalachia	Pittsburgh	0.1	0.2	0.8	0.0	0.0	0.1	0.9	1.6	3.4
	Upper Freeport	0.1	0.2	0.6	0.0	0.0	0.0	0.8	1.3	2.1
	Lower Kittanning	0.2	0.4	1.5	0.0	0.1	0.1	3.0	4.0	6.4
	Pond Creek	0.1	0.2	0.8	0.0	0.0	0.1	0.9	1.7	4.1
	Fire Clay	0.1	0.2	0.7	0.0	0.0	0.1	0.9	1.6	3.7
	Pocohontas	0.1	0.2	0.8	0.0	0.0	0.1	0.9	1.5	3.7
Illinois	Springfield	0.2	0.4	1.5	0.0	0.1	0.1	2.7	3.6	5.8
	Herrin	0.1	0.3	1.5	0.0	0.0	0.2	1.2	2.4	7.8
	Danville	0.2	0.5	1.5	0.0	0.1	0.1	2.8	3.7	5.8

Table C97. Water induced erosion cost ($/ton of coal produced). These are the cost of topsoil replacement.

Region	Coalfield	Longwall			Continuous			Surface		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	NA	NA	NA	NA	NA	NA	8.E-07	5.E-06	1.E-05
	Deserado	NA	NA	NA	NA	NA	NA	6.E-05	3.E-04	7.E-04
	South Piceance	1.E-05	8.E-05	4.E-04	1.E-06	1.E-05	4.E-05	1.E-04	6.E-04	2.E-03
	South Wasatch	1.E-05	5.E-05	3.E-04	1.E-06	7.E-06	2.E-05	8.E-05	5.E-04	1.E-03
	Yampa	1.E-05	9.E-05	3.E-04	1.E-06	1.E-05	4.E-05	9.E-05	6.E-04	2.E-03
	Henry Mountains	1.E-05	7.E-05	5.E-04	2.E-06	1.E-05	4.E-05	1.E-04	7.E-04	2.E-03
Rocky Mountains and Great Plains	San Juan	9.E-06	8.E-05	3.E-04	1.E-06	9.E-06	3.E-05	1.E-04	5.E-04	1.E-03
	Ashland	2.E-06	2.E-05	1.E-04	3.E-07	2.E-06	9.E-06	2.E-05	1.E-04	5.E-04
	Colstrip	6.E-06	4.E-05	2.E-04	6.E-07	4.E-06	2.E-05	4.E-05	3.E-04	1.E-03
	Decker	2.E-06	1.E-05	6.E-05	2.E-07	1.E-06	4.E-06	1.E-05	7.E-05	2.E-04
	Gillette	1.E-06	9.E-06	5.E-05	2.E-07	1.E-06	4.E-06	9.E-06	6.E-05	2.E-04
	Sheridan	2.E-06	1.E-05	5.E-05	2.E-07	1.E-06	5.E-06	2.E-05	7.E-05	2.E-04
	Williston-Beulah-Zap	7.E-06	4.E-05	2.E-04	7.E-07	5.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Williston-Hagel	6.E-06	4.E-05	2.E-04	8.E-07	5.E-06	2.E-05	4.E-05	3.E-04	9.E-04
	Williston-Hansen	8.E-06	5.E-05	3.E-04	9.E-07	5.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Williston-Harmon	7.E-06	4.E-05	2.E-04	1.E-06	4.E-06	2.E-05	5.E-05	3.E-04	9.E-04
	Hanna-Ferris 23, 25,31,50,65	NA	NA	NA	NA	NA	NA	1.E-05	9.E-05	2.E-04
	Hanna-Hanna 77,78,79,81	NA	NA	NA	NA	NA	NA	7.E-06	4.E-05	8.E-05
	Carbon-Johnson	4.E-06	3.E-05	1.E-04	4.E-07	3.E-06	1.E-05	3.E-05	2.E-04	5.E-04
	Green River-Dead Man	6.E-06	3.E-05	1.E-04	5.E-07	4.E-06	1.E-05	3.E-05	2.E-04	8.E-04
Gulf Coast	Wilcox	NA	NA	NA	NA	NA	NA	1.E-03	3.E-03	1.E-02
	Lower Wilcox	NA	NA	NA	NA	NA	NA	9.E-04	3.E-03	2.E-02
Appalachia	Pittsburgh	1.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	1.E-03	4.E-03	1.E-02
	Upper Freeport	2.E-04	4.E-04	2.E-03	2.E-05	6.E-05	2.E-04	9.E-04	3.E-03	8.E-03
	Lower Kittanning	3.E-04	1.E-03	6.E-03	6.E-05	2.E-04	5.E-04	4.E-03	1.E-02	3.E-02
	Pond Creek	2.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	1.E-03	5.E-03	1.E-02
	Fire Clay	1.E-04	6.E-04	3.E-03	2.E-05	7.E-05	3.E-04	1.E-03	4.E-03	1.E-02
	Pocohontas	1.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	2.E-03	4.E-03	1.E-02
Illinois	Springfield	4.E-04	1.E-03	5.E-03	7.E-05	2.E-04	5.E-04	3.E-03	1.E-02	3.E-02
	Herrin	2.E-04	9.E-04	4.E-03	3.E-05	1.E-04	5.E-04	2.E-03	7.E-03	3.E-02
	Danville	3.E-04	1.E-03	7.E-03	5.E-05	2.E-04	6.E-04	5.E-05	7.E-05	1.E-04

Table C98. Calculated cost of soil replacement for wind induced erosion ($/ton of coal produced)

Region	Coalfield	LW ($/ton coal)			CM ($)			SM ($)		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	NA	NA	NA	NA	NA	NA	1.E-07	2.E-07	3.E-07
	Deserado	NA	NA	NA	NA	NA	NA	8.E-06	1.E-05	2.E-05
	South Piceance	1.E-06	3.E-06	1.E-05	2.E-07	4.E-07	1.E-06	2.E-05	2.E-05	5.E-05
	South Wasatch	1.E-06	2.E-06	7.E-06	1.E-07	3.E-07	5.E-07	1.E-05	2.E-05	2.E-05
	Yampa	1.E-06	3.E-06	9.E-06	2.E-07	4.E-07	9.E-07	1.E-05	2.E-05	5.E-05
	Henry Mountains	1.E-06	3.E-06	1.E-05	2.E-07	4.E-07	1.E-06	2.E-05	3.E-05	5.E-05
Rocky Mountains and Great Plains	San Juan	1.E-06	3.E-06	8.E-06	2.E-07	3.E-07	9.E-07	1.E-05	2.E-05	4.E-05
	Ashland	3.E-07	8.E-07	3.E-06	4.E-08	9.E-08	2.E-07	2.E-06	5.E-06	1.E-05
	Colstrip	6.E-07	2.E-06	6.E-06	7.E-08	2.E-07	6.E-07	6.E-06	1.E-05	3.E-05
	Decker	1.E-07	4.E-07	2.E-06	2.E-08	5.E-08	2.E-07	2.E-06	3.E-06	8.E-06
	Gillette	1.E-07	4.E-07	1.E-06	2.E-08	4.E-08	1.E-07	1.E-06	2.E-06	7.E-06
	Sheridan	1.E-07	5.E-07	2.E-06	2.E-08	5.E-08	2.E-07	2.E-06	3.E-06	8.E-06
	Williston-Beulah-Zap	6.E-07	2.E-06	6.E-06	8.E-08	2.E-07	4.E-07	6.E-06	1.E-05	3.E-05
	Williston-Hagel	6.E-07	2.E-06	7.E-06	8.E-08	2.E-07	5.E-07	6.E-06	1.E-05	3.E-05
	Williston-Hansen	6.E-07	2.E-06	8.E-06	8.E-08	2.E-07	7.E-07	6.E-06	1.E-05	4.E-05
	Williston-Harmon	5.E-07	2.E-06	6.E-06	9.E-08	2.E-07	5.E-07	6.E-06	1.E-05	3.E-05
	Hanna-Ferris 23, 25,31,50,65	NA	NA	NA	NA	NA	4.E-07	2.E-06	3.E-06	4.E-06
	Hanna-Hanna 77,78,79,81	NA	NA	NA	NA	NA	4.E-07	1.E-06	1.E-06	2.E-06
	Carbon-Johnson	4.E-07	1.E-06	5.E-06	5.E-08	1.E-07	9.E-07	5.E-06	7.E-06	2.E-05
	Green River-Dead Man	5.E-07	2.E-06	4.E-06	7.E-08	1.E-07	1.E-06	5.E-06	8.E-06	2.E-05
Gulf Coast	Wilcox	8.E-07	2.E-06	1.E-05	9.E-08	2.E-07	NA	6.E-06	1.E-05	5.E-05
	Lower Wilcox	5.E-07	2.E-06	7.E-06	8.E-08	3.E-07	NA	6.E-06	1.E-05	6.E-05
Appalachia	Pittsburgh	1.E-06	3.E-06	2.E-05	2.E-07	5.E-07	1.E-06	2.E-05	3.E-05	6.E-05
	Upper Freeport	1.E-06	3.E-06	1.E-05	2.E-07	4.E-07	9.E-07	2.E-05	2.E-05	4.E-05
	Lower Kittanning	3.E-06	8.E-06	3.E-05	7.E-07	1.E-06	3.E-06	6.E-05	8.E-05	1.E-04
	Pond Creek	1.E-06	4.E-06	2.E-05	2.E-07	5.E-07	2.E-06	2.E-05	3.E-05	8.E-05
	Fire Clay	1.E-06	4.E-06	1.E-05	2.E-07	5.E-07	1.E-06	2.E-05	3.E-05	7.E-05
	Pocohontas	1.E-06	3.E-06	2.E-05	2.E-07	5.E-07	1.E-06	2.E-05	3.E-05	7.E-05
Illinois	Springfield	3.E-06	8.E-06	3.E-05	5.E-07	1.E-06	2.E-06	5.E-05	7.E-05	1.E-04
	Herrin	2.E-06	5.E-06	3.E-05	3.E-07	7.E-07	3.E-06	2.E-05	5.E-05	1.E-04
	Danville	3.E-06	9.E-06	3.E-05	6.E-07	1.E-06	2.E-06	5.E-05	7.E-05	1.E-04

Table C99. Erosion cost ($/ton of coal produced). Costs shown are soil replacement costs for wind and water induced erosion.

		Longwall			Continuous			Surface		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	NA	NA	NA	NA	NA	NA	9.E-07	5.E-06	1.E-05
	Deserado	NA	NA	NA	NA	NA	NA	6.E-05	3.E-04	7.E-04
	South Piceance	2.E-05	9.E-05	4.E-04	1.E-06	1.E-05	4.E-05	1.E-04	6.E-04	2.E-03
	South Wasatch	1.E-05	6.E-05	3.E-04	2.E-06	7.E-06	2.E-05	9.E-05	5.E-04	1.E-03
	Yampa	1.E-05	9.E-05	4.E-04	2.E-06	1.E-05	4.E-05	1.E-04	6.E-04	2.E-03
	Henry Mountains	2.E-05	8.E-05	5.E-04	3.E-06	1.E-05	4.E-05	1.E-04	8.E-04	2.E-03
	San Juan	1.E-05	8.E-05	3.E-04	2.E-06	1.E-05	3.E-05	1.E-04	6.E-04	2.E-03
Rocky Mountains and Great Plains	Ashland	3.E-06	2.E-05	1.E-04	3.E-07	2.E-06	9.E-06	2.E-05	1.E-04	5.E-04
	Colstrip	6.E-06	4.E-05	2.E-04	7.E-07	5.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Decker	2.E-06	1.E-05	6.E-05	2.E-07	1.E-06	5.E-06	1.E-05	7.E-05	2.E-04
	Gillette	1.E-06	9.E-06	5.E-05	2.E-07	1.E-06	5.E-06	1.E-05	6.E-05	2.E-04
	Sheridan	2.E-06	1.E-05	5.E-05	3.E-07	1.E-06	5.E-06	2.E-05	7.E-05	2.E-04
	Williston-Beulah-Zap	8.E-06	4.E-05	2.E-04	8.E-07	5.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Williston-Hagel	7.E-06	4.E-05	2.E-04	9.E-07	5.E-06	2.E-05	5.E-05	3.E-04	9.E-04
	Williston-Hansen	9.E-06	5.E-05	3.E-04	1.E-06	5.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Williston-Harmon	8.E-06	4.E-05	2.E-04	1.E-06	4.E-06	2.E-05	5.E-05	3.E-04	1.E-03
	Hanna-Ferris 23, 25,31,50,65	NA	NA	NA	NA	NA	4.E-07	2.E-05	9.E-05	2.E-04
	Hanna-Hanna 77,78,79,81	NA	NA	NA	NA	NA	4.E-07	8.E-06	4.E-05	8.E-05
	Carbon-Johnson	4.E-07	1.E-06	5.E-06	5.E-08	1.E-07	1.E-05	4.E-05	2.E-04	6.E-04
	Green River-Dead Man	5.E-07	2.E-06	4.E-06	7.E-08	1.E-07	1.E-05	4.E-05	2.E-04	8.E-04
Gulf Coast	Wilcox	5.E-06	3.E-05	1.E-04	5.E-07	3.E-06	0.E+00	1.E-03	3.E-03	1.E-02
	Lower Wilcox	7.E-06	4.E-05	1.E-04	6.E-07	4.E-06	0.E+00	9.E-04	3.E-03	2.E-02
Appalachia	Pittsburgh	1.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	1.E-03	5.E-03	1.E-02
	Upper Freeport	2.E-04	4.E-04	2.E-03	2.E-05	6.E-05	2.E-04	9.E-04	4.E-03	9.E-03
	Lower Kittanning	3.E-04	1.E-03	6.E-03	6.E-05	2.E-04	5.E-04	4.E-03	1.E-02	3.E-02
	Pond Creek	2.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	1.E-03	5.E-03	1.E-02
	Fire Clay	1.E-04	6.E-04	3.E-03	2.E-05	7.E-05	3.E-04	1.E-03	5.E-03	1.E-02
	Pocohontas	1.E-04	6.E-04	3.E-03	2.E-05	8.E-05	3.E-04	2.E-03	4.E-03	1.E-02
Illinois	Springfield	4.E-04	1.E-03	5.E-03	7.E-05	2.E-04	5.E-04	3.E-03	1.E-02	3.E-02
	Herrin	2.E-04	9.E-04	4.E-03	3.E-05	1.E-04	5.E-04	2.E-03	8.E-03	3.E-02
	Danville	3.E-04	1.E-03	7.E-03	6.E-05	2.E-04	6.E-04	1.E-04	3.E-04	2.E-03

C.7 Water consumption

Water consumption rates are not extensively quantified throughout the mining process. Some water use rules of thumb are available for a few pieces of underground mining units [36] and surface dust control [37], but more information is needed. The scant water consumption data available state that continuous mining units use 10 – 40 gallons/minute at working pressure of 200 – 300 psi, longwall shearers need 60 – 120 gallons/minute at 200 – 300 psi, belt lines use 5 – 10 gallons/minute, and dust control requires 5.2 gallons per ton of coal mined.

C.8 Acid mine drainage

C.8.1 Acid generation potential

The two predominant methods of acid generation potential are static and kinetic testing. Static testing is a calculation based on the sulfur content, assuming complete reaction that produces two moles of acid for each mole of sulfur:

$$APP_{MAX} = \%S \times cf \qquad (13)$$

where APP_{MAX} = maximum acid production potential, ton acid per ton rock
$\%S$ = percent of sulfur in coal
cf = conversion factor, 31.25

The static test estimates acid generation potential. This rule of thumb (Equation 4) assumes that all sulfur in the coal is converted to sulfuric acid; it assumes the worst case, that all available sulfur will be exposed to water and oxygen to form acid. A shortcoming to choosing the static test is that it only addresses acid formation. It does not estimate metal pollutant emissions from coal mining. The kinetic test consists of a laboratory simulation of the acid reaction over time. Reaction rates and effluent concentrations are measured. These measurements are used as an empirical basis to estimate future acid formation and metal leaching, but it is time consuming to collect samples and examine them.

C.8.2 Acid mine drainage cost

Underground mine coal surface area that must be coated is calculated:

$$CC = \frac{SF \times CP}{P} \tag{14}$$

where CC = coating cost (\$/ton)
SF = surface area of exposed workings (ft^2)
CP = coating price (\$/ft^2)

For surface mines, the surface area is calculated:

$$SF_{pit} = 2n_{pit}L_{pit}W_{pit}\sum(h+m)L_{pit} + A_{pit} \tag{15}$$

where SF_{pit} = pit surface area (ft^2)
n_{pit} = number of pits
L_{pit} = pit length (ft)
W_{pit} = pit width (ft)
h = overburden and interburden depth (ft)
m = seam height (ft)
L_{pit} = pit length (ft)

The calculated acid mine drainage avoidance costs are shown in Table C19 and Table C20. Because sealant and grout material cost are so similar, the cost to use them is the same.

Underground coating costs range from \$2 - \$12/ton for most longwall mines and cost less than \$5/ton for most continuous mines. Coating surface mine pits incurs a larger range of cost; using a landfill liner is the cheaper option. The landfill liner option is on average 10 percent of the cost of the coating option.

Table C100. Calculated underground mine sealant or grout cost ($/Ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	2	4	12	0	1	3
	South Wasatch	2	4	12	0	1	3
	Yampa	2	4	12	0	1	5
	Henry Mountains	2	4	12	0	1	5
	San Juan	2	4	12	0	1	5
Rocky Mountains and Great Plains	Ashland	3	9	55	1	4	11
	Colstrip	2	5	22	0	1	5
	Decker	6	17	72	0	3	18
	Gillette	7	21	92	2	7	23
	Sheridan	6	19	66	1	6	20
	Williston-Beulah-Zap	2	5	24	0	1	2
	Williston-Hagel	2	5	20	0	0	2
	Williston-Hansen	2	5	19	0	1	3
	Williston-Harmon	2	5	21	0	1	3
	Carbon-Johnson	2	8	25	0	1	3
	Green River-Dead Man	2	6	22	0	1	5
Gulf Coast	Wilcox	2	5	15	0	0	2
	Lower Wilcox	2	5	17	0	0	2
Appalachia	Pittsburgh	2	4	12	0	1	4
	Upper Freeport	2	4	12	0	1	3
	Lower Kittanning	2	4	12	1	3	8
	Pond Creek	2	4	12	0	1	5
	Fire Clay	2	4	12	0	1	5
	Pocohontas	2	4	12	0	1	6
Illinois	Springfield	2	4	12	0	2	5
	Herrin	2	4	12	0	1	6
	Danville	2	4	12	0	2	3

Table C101. Calculated surface mine acid mine drainage avoidance costs ($/ton of coal produced)

Region	Coalfield	Sealant or Grout			Landfill Liner		
		0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0	1	5	0	0	1
	Deserado	1	10	461	0	1	58
	South Piceance	2	77	2509	0	7	206
	South Wasatch	3	53	702	0	6	90
	Yampa	4	64	2954	0	7	253
	Henry Mountains	2	36	1438	0	4	175
	San Juan	3	64	1266	0	9	128
Rocky Mountains and Great Plains	Ashland	1	10	565	0	1	57
	Colstrip	1	11	347	0	1	35
	Decker	0	2	44	0	0	5
	Gillette	1	4	78	0	0	10
	Sheridan	1	5	85	0	1	6
	Williston-Beulah-Zap	1	5	84	0	1	8
	Williston-Hagel	1	3	42	0	0	4
	Williston-Hansen	1	7	88	0	1	8
	Williston-Harmon	1	4	47	0	0	4
	Hanna-Ferris 23, 25,31,50,65	1	12	297	0	1	26
	Hanna-Hanna 77,78,79,81	1	4	100	0	0	7
	Carbon-Johnson	2	21	275	0	2	31
	Green River-Dead Man	1	3	32	0	0	3
Gulf Coast	Wilcox	1	3	46	0	0	5
	Lower Wilcox	1	4	47	0	0	5
Appalachia	Pittsburgh	2	17	437	0	2	71
	Upper Freeport	2	25	348	0	3	46
	Lower Kittanning	44	727	6623	3	76	805
	Pond Creek	3	70	1079	1	8	87
	Fire Clay	2	33	738	0	3	83
	Pocohontas	4	101	2067	0	11	190
Illinois	Springfield	4	93	2616	0	9	175
	Herrin	3	49	793	0	5	66
	Danville	71	2287	6573	0	7	245

C.9 Air emissions estimation

Coal Cleaning Emissions Factors

There are a variety of methods available to clean coal. Due to the need to represent all possible options, the full range of emissions factors associated with each cleaning option is used to describe potential coal preparation plant emissions. Coal cleaning can be a chemical or mechanical process. The latter method consists of a crushing and screening process to mechanically separate coal from dirt and rocks that are embedded in the seam and included in the extracted coal. Due to the nature of this procedure, coal dust is generated and may escape as an air emission. Particulate matter, SO_2, NO_X, are also emitted as combustion products formed when the coal is heated and dried. In many cases, a scrubber is used to minimize pollutant emissions. The emission factors for preparation plants that have pollutant scrubbing devices are included (Table C102).

Table C102. Coal cleaning emissions factors [38]

Pollutant	Emissions factor (lb/ton of coal)
PM	0.025 – 26
SO_2	0.072 – 1.4
NO_X	0.16
CH_4	0.098
CO_2	30

Emissions from Ground breaking and overburden removal

During surface mining, strata overlying the coal, or overburden, is removed and broken in order to access the seam. Shafts or slopes are dug into the earth for underground mine access. At surface mines, ammonium nitrate fuel oil (ANFO) is used to break up the material, so that it can then be removed by truck and shovel. Explosive detonation emits 67 pounds of CO, 2 pounds of SO_2, and 17 pounds of NO_X, per ton of ANFO [39]. It does not emit any other pollutants of interest.

Truck loading, bulldozing, and vehicle site travel emit dust. In this analysis, total suspended particulate (TSP) that is dirt and dust loosened by vehicle and machinery. The equations to calculate TSP emission factors are reprinted in Table C25.

All of these emission factor equations are used, except for the dragline emissions factor. The model (Chapter 2) does not model draglines, because it assumes that surface mines are truck and shovel operations. To use these equations the mined area as estimated by the model, is used for A, the horizontal blasting area. Vehicle speed, S, is the truck vehicle speed assumed by the model; 15 – 30 mph [36]. Silt (s), soil moisture (M) are found in the NOAA and USGS soil databases.

Table C103. Emission factor equations for uncontrolled open dust sources at western surface coal mines [33]

		Emissions by Particle Size Range (Aerodynamic Diameter)				
		Emission Factor Equations		Scaling Factors		
Operation	Material	TSP ≤ 30 µm	TSP ≤ 15 µm	TSP ≤ 10 µm	TSP ≤ 2.5 µm/TSP	Units
Blasting	Coal or overburden	$0.000014(A)^{1.5}$	ND	0.52	0.03	Lb/blast
Truck loading	Coal	$\frac{1.16}{(M)^{1.2}}$	$\frac{0.119}{(M)^{0.9}}$	0.75	0.019	Lb/ton
Bulldozing	Coal	$\frac{78.4(s)^{1.2}}{(M)^{1.3}}$	$18.6(s)^{1.5}$	0.75	0.022	Lb/hr
	Overburden	$\frac{5.7(s)^{1.2}}{(M)^{1.3}}$	$\frac{1.0(s)^{1.5}}{(M)^{1.4}}$	0.75	0.105	Lb/hr
Dragline	Overburden	$\frac{0.0021(d)^{1.1}}{(M)^{0.3}}$	$\frac{0.0021(d)^{0.7}}{(M)^{0.3}}$	0.75	0.017	Lb/yd^3
Vehicle traffic		$0.04(S)^{2.5}$	$0.051(S)^{2.0}$	0.60	0.031	Lb/VMT
Active storage pile (wind erosion and maintenance)	Coal	0.72u	ND	ND	ND	$\frac{lb}{(acre)(hr)}$

Symbols for equations:
A = horizontal area (ft^2), with blasting depth ≤ 70 ft. Not for vertical face of a bench.
M = material moisture content (%)
s = material silt content (%)
u = wind speed (mph)
d = drop height (ft)
W = mean vehicle weight (tons)
S = mean vehicle speed (mph)
w = mean number of wheels

To calculate these emissions factors, coal moisture, soil moisture and silt data are needed in order to tailor the emissions factors to the mine location. The data indicate soil dryness and erodibility. Soil moisture, silt, and coal moisture data are collected for all the NCRA regions. The National Coal Quality Inventory (NaCQI), a 729 sample set, catalogs coal quality data for seams to be mined in the next 20 – 30 years. It has moisture data for the regions named the Northern Great Plains Province (Wyoming), Rocky Mountain (Wyoming and Colorado), Interior (Oklahoma, Illinois, Indiana, Kentucky) and Eastern

Province (Kentucky, Pennsylvania, Tennessee, West Virginia.) Although the overlap is not perfect, moisture data is assigned to NCRA regions so that the Northern Great Plains Province is the Rocky Mountains ad Great Plains, Rocky Mountain is Colorado Plateau, Interior is Illinois, and Eastern Province is Appalachia. Monthly soil moisture data is available in map-only form from the national Oceanic and Atmospheric Administration. The uniform distribution of soil moisture data per coal producing region are determined as the range of average monthly high and low soil moisture. The United States Department of Agriculture (USDA) Soil Survey Laboratory maintains a dataset of soil silt content based on thousands of U.S. soil samples. Soil moisture and silt data per coal producing region is shown in Table C104.

Table C104. Percent coal moisture, soil moisture and silt data per NCRA region

Region	Percent coal moisture [40, 41] (low, average, high)	Percent soil moisture [42] (low, high)	Percent soil silt [43] (low, average, high)
Colorado Plateau	(0, 5, 31)	(36, 59)	(2, 30, 80)
Rocky Mountains and Great Plains	(9, 21, 32)	(20, 69)	(1, 35, 77)
Gulf Coast	33[a]	(37, 41)	(0, 42, 78)
Appalachia	(0, 1, 4)	(48, 71)	(2, 42, 82)
Illinois	(0, 3, 14)	(55, 79)	(2, 55, 90)

[a]Gulf Coast data is not available in the NaCQUI, coal moisture data was found in a Texas coal study [41].

The Soil Survey Laboratory provides soil sample data from the National Cooperative Soil Survey. The laboratory is emphatic that data quality is not guaranteed. However, this is the most complete U.S. soil silt content data set available. The soil data included in the EPA AP-42 [33] only address soils in Colorado, Wyoming, Montana and North Dakota. Triangle distribution of this data was chosen to represent silt data because enough data were available to ascertain low, average, and high values. Moisture data is represented by uniform distribution due to the lack of precision in reporting the data.

Vehicle Fuel Use Emissions Factors

Vehicles are used on site to move people and material. The fuel combustion releases VOCs, CO, PM and NO_X. Although there are several models available to estimate emissions from vehicle transit, many are focused solely on light passenger vehicles. The government uses EPA MOBILE6, which was developed to support State Implementation Plans for NO_X compliance under the Clean Air Act. The model can estimate emission factors for any year 1952 – 2050 for any of 28 vehicle types. The diesel truck local road emission factors are used to estimate surface mine vehicle emissions, assuming that this type of low-speed stop-and-go movement would be representative of minesite traffic. The emissions factors, as developed by the Federal Highway Administration (FHWA), are shown in Table C105 and are used to calculate the emissions resulting from truck trips in and out of the surface mine pit. Emissions from bulldozers and shovels are not calculated. Moreover, emissions from grading vehicles could not be determined because the model, while calculating the area disturbed by surface or underground mining, does not determine the total mileage traveled by a grader. Grader dimensions are not available in order to estimate miles traveled to regrade post-mining land.

Table C105. Vehicular fuel use emission factors (grams/mile) [44]

	CO	NO_X	PM_{10}
Single-unit diesel truck	0.007	0.016	3.75×10^{-4}
Combination diesel truck	0.008	0.016	3.75×10^{-4}

Greenhouse gas emissions are calculated for all equipment that consume diesel. This analysis assumes that mine vehicles are similar to construction vehicles, and emit 0.26 grams N_2O, 0.58 grams of CH_4 and 22.37 pounds of CO_2 per gallon of diesel [45]. To convert all greenhouse gas emissions to CO_2 equivalent, it is assumed that CH_4 and N_2O have 100 year global warming potentials 21 and 310 times that of CO_2 [46], respectively.

The criteria and greenhouse gas emissions factors are converted from an emissions-per-mileage or fuel-consumption basis to a mine-output basis. The model estimates the amount of fuel consumed by surface mine equipment (gallons of diesel), and the total number of trips that trucks must take in and out of mining pits to move overburden and coal (mileage). The mine output is also known, so fuel use per coal production and mileage per coal production can be determined. These ratios are used to convert the emissions factors to a emission-per-mine-output basis.

Emissions from Electricity Consumption

Electricity emissions per region, assuming that electricity is purchased within the region, are estimated from EIA data and the EPA Emissions and Generation Resource Integrated Database (EGRID), summarized in Table C106. These regional emission factors are used to estimate air emissions from electricity consumed. Emissions from onsite generation are not calculated.

Table C106. Pollutant emissions from power production (lb/MWh) [47, 48].

	CO_2	CH_4	N_2O	NO_X	SO_2
Colorado Plateau	1829	0.01	0.03	3	3
Rocky Mountains and Great Plains	2079	0.01	0.03	4	5
Gulf Coast	1336	0.01	0.01	1	3
Appalachia	1649	0.01	0.03	3	10
Illinois	1768	0.01	0.03	3	10

The emissions shown in Table C106 are the average EGRID reported emissions for states in each region. Colorado Plateau emissions are averaged from EGRID Colorado, New Mexico, Arizona, and Utah data; Rocky Mountains and Great Plains emissions are averaged from EGRID Wyoming, Montana, and North Dakota data; Gulf Coast emissions are averaged from EGRID Texas and Louisiana data; Appalachia emissions are averaged from EGRID Pennsylvania, West Virginia, Ohio, Maryland, Kentucky and Tennessee data; Illinois emissions are averaged from EGRID Illinois, Indiana and Kentucky data.

As described in Chapter 2, the model estimates the amount of electricity consumed by underground mining equipment. The total electricity needed to produce a ton of coal is determined, and related emissions calculated by using the data in Table C106.

C.9 Comparison of EPA Methane regions and NCRA Coal regions

EPA's analysis defines fourteen coalbed methane regions. The Northern Appalachia methane region contains the Pittsburgh, Upper Freeport and Lower Kittanning coalfields while the Central Appalachia methane region has the Fire Clay, Pond Creek and

Pocohontas coalfields [49]. There is no NCRA coalbed in the Warrior methane region. The coalfields in the Illinois methane basin correspond to those defined by the NCRA. The NCRA Northern Rocky Mountains and Great Plains defined by the NCRA is assumed to be the same as the EPA defined "Northern Great Plains" except for Green River, which has its own assessment within the EPA defined "Rockies." The Rockies (Piceance Basin) is assumed to house the Danforth and South Piceance coalfields although the latter is found in both the Piceance and Uinta Basins. The Rockies (Uinta Basin) is assumed to house the South Wasatch, Henry Mountains, Deserado and Yampa coalfields. Although the Henry Mountains are not technically in the Uinta Basin, it is located close enough that it is assumed that it has the same methane quality. The San Juan coalfield is assumed to be in the Rockies (San Juan Basin), and no coal data is available for the West Interior or Northwest.

C.10 Methane development costs

Cost and quantity estimation data provided by the EPA for a coalbed methane development project are shown in Table C107.

Table C107. Coalbed methane project cost and size data [50, 51]

Component	Number or Size of Units	Cost per Unit	Operating Cost per unit ($/Year)	Recovery Efficiency[a]
Degasification system (cost to drill, install, and complete wells and boreholes)				
Gob wells	1 for every 200,000 – 500,000 tons coal/year 2-5 wells per panel	$307,900 - $535,000	20,000 – 40,000	Up to 50%
Premining vertical wells	1 well for every 250,000 – 1,000,000 tons of coal over the lifetime. Well spacing 20-80 acres.	$320,000 - $640,000	20,000 – 40,000	Up to 70%
Longhole horizontal boreholes	1 longwall hole borehole drilled per year per 1 million tons of coal (1 per longwall panel)	$60,000 - $100,000 per 1 million tons of coal. Includes drilling cost of $50-$80/m for 1200 m hole	105,000 – 640,000	Up to 50%
Capital cost for water disposal for vertical premining degasifcation wells	1 disposal system per project [51]	$100,000 - $2,800,000		
Operating cost for water disposal for vertical pre-mining degasification wells	17-70 barrels per tcm of gas produced [51]	$0.02 - $2/barrel		
Coalbed methane water treatment/disposal technologies		28,000 – 1,872,000[b]		

[a]Percent of methane that would otherwise be emitted.
[b]Annual cost ($/Year) based on 20 year project life and 10% discount rate

The cost to drill wells and operate them is estimated. Dehydrating the gas or enriching it to be input to a pipeline or for sale is not calculated. Because water production rates are not known, the cost to treat water is not calculated, although the capital cost of a water treatment project is included in methane abatement cost.

The cost for methane collection is calculated using the capital and operating costs in Table C107:

$MC = \dfrac{\sum CapM_j + \sum NPV_{op,j}}{P}$		*(16)*
where	MC = methane abatement cost ($/Ton) $CapM_j$ = capital cost of methane project equipment j, shown in the 3rd column of Table C107 $NPV_{op,j}$ = net present value of operating methane project equipment j shown in the 4th column of Table C107, for the operating period shown in Table C108 P = total lifetime mine production	

Table C108. Operating period used to calculated operating cost NPV

Equipment	Operating period (years)
Gob well	Mine lifetime as calculated in model
Vertical wells	5
Longwall horizontal borehole	3
Water disposal in premining	5
Coalbed methane water treatment	5

The number of each piece of equipment is determined as shown in Table C109, based on the guidelines given in Table C107. The guidelines state that 2-5 gob wells are needed per mining panel, so the number of wells can be determined by multiplying the number of panels by a uniform distribution of 2 to 5 wells. The guidelines also state that 1 pre-mining vertical well is needed per every 250,000 – 1,000,000 tons of coal produced over the mine's lifetime, so the number of vertical wells needed is calculated by dividing estimated lifetime production by a uniform distribution of 250,000 to 1,000,000 tons of coal per well.

Table C109. Equipment quantity per methane reduction option. Key to variables is below table.

Equipment	Option1	Option 2	Option 3	Option 4
Gob wells	$N_{panels} \times uniform(2,5)$	0	$N_{panels} \times uniform(2,5)$	$N_{panels} \times uniform(2,5)$
Vertical wells	0	$\dfrac{P}{uniform(250 \times 10^3, 10^6)}$	$\dfrac{P}{uniform(250 \times 10^3, 10^6)}$	$\dfrac{P}{uniform(250 \times 10^3, 10^6)}$
Horizontal boreholes	0	0	0	N_{panels}
Water disposal system for vertical wells	0	1	1	1
Water disposal system for coalbed methane water	1	0	1	1

N_{panels} = number of longwall panels in longwall mine or sections of rooms and pillars in a continuous mine
P = total lifetime mine production
Uniform(x, y) = uniform distribution between numbers x and y

Using the number of equipment shown in Table C109, and the equipment lifetime given in Table C108, the costs can be computed using Equation 16. Results are shown in Tables C32 – C35.

Table C110. Option 1 methane mitigation costs for underground mines, $/ton of coal produced

Region	Coalfield	Longwall			Continuous		
		0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	11	15	30	12	17	25
	South Wasatch	11	15	30	11	16	24
	Yampa	11	15	31	12	17	25
	Henry Mountains	11	15	31	12	17	25
	San Juan	11	15	30	12	17	25
Rocky Mountains and Great Plains	Ashland	11	15	30	11	16	24
	Colstrip	11	15	30	11	16	24
	Decker	11	15	30	11	16	24
	Gillette	11	17	26	11	17	26
	Sheridan	11	17	26	11	17	26
	Williston-Beulah-Zap	11	17	26	11	17	26
	Williston-Hagel	11	17	26	11	17	26
	Williston-Hansen	11	17	26	11	17	26
	Williston-Harmon	11	17	26	11	17	26
	Carbon-Johnson	11	17	26	11	17	26
	Green River-Dead Man	11	17	26	11	17	26
Gulf Coast	Wilcox	11	17	26	11	17	26
	Lower Wilcox	11	17	26	11	17	26
Appalachia	Pittsburgh	10	16	30	12	17	29
	Upper Freeport	10	15	30	11	16	27
	Lower Kittanning	11	16	31	14	18	32
	Pond Creek	10	16	30	12	16	28
	Fire Clay	11	16	30	12	17	28
	Pocohontas	11	16	30	12	17	29
Illinois	Springfield	11	16	31	13	18	32
	Herrin	11	16	32	13	17	32
	Danville	11	16	31	13	18	30

Table C111 Option 2 Methane mitigation costs for all mine types ($/ton of coal produced)

		Longwall			Continuous			Surface		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills							6	9	24
	Deserado							7	15	43
	South Piceance	6	11	24	7	13	22	11	33	219
	South Wasatch	6	11	24	7	12	22	10	30	146
	Yampa	6	11	24	7	13	22	13	36	243
	Henry Mountains	6	11	24	7	13	23	10	25	167
	San Juan	6	11	24	7	12	22	10	34	184
Rocky Mountains and Great Plains	Ashland	6	11	23	7	12	22	8	17	60
	Colstrip	6	11	23	7	12	22	8	17	53
	Decker	6	11	23	7	12	22	7	11	25
	Gillette	6	10	24	7	11	24	7	12	32
	Sheridan	6	10	24	7	11	24	7	12	30
	Williston-Beulah-Zap	6	10	24	7	11	24	7	12	40
	Williston-Hagel	6	10	25	8	11	24	6	11	25
	Williston-Hansen	6	10	24	7	11	24	7	13	31
	Williston-Harmon	6	10	24	7	11	24	6	11	25
	Hanna-Ferris 23, 25,31,50,65							7	14	38
	Hanna-Hanna 77,78,79,81							6	12	26
	Carbon-Johnson	6	10	24	7	11	24	7	17	75
	Green River-Dead Man	6	10	24	7	11	24	6	11	24
Gulf Coast	Wilcox	7	10	25	8	11	24	7	12	28
	Lower Wilcox	6	10	24	8	12	24	7	12	33
Appalachia	Pittsburgh	7	11	27	7	13	26	8	18	179
	Upper Freeport	7	11	27	8	12	26	9	18	110
	Lower Kittanning	7	12	28	9	16	32	52	217	2083
	Pond Creek	7	11	27	8	13	27	10	34	414
	Fire Clay	7	11	28	8	13	25	9	25	177
	Pocohontas	7	11	27	7	13	26	12	46	652
Illinois	Springfield	7	12	28	9	15	28	9	35	522
	Herrin	7	12	27	8	14	29	12	27	723
	Danville	7	12	28	9	15	30	11	43	575

Table C112. Option 3 Methane mitigation costs for underground mines ($/Ton of coal produced)

		Longwall			Continuous		
	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	18	27	47	20	29	41
	South Wasatch	18	27	46	19	28	39
	Yampa	18	27	46	20	28	40
	Henry Mountains	18	27	46	20	29	41
	San Juan	18	27	47	20	28	41
Rocky Mountains and Great Plains	Ashland	18	27	46	19	28	39
	Colstrip	18	26	46	19	28	39
	Decker	18	26	46	19	28	39
	Gillette	18	27	50	19	27	40
	Sheridan	18	27	50	19	27	40
	Williston-Beulah-Zap	18	27	50	19	27	40
	Williston-Hagel	18	27	50	19	27	40
	Williston-Hansen	18	27	50	19	28	41
	Williston-Harmon	18	27	50	19	28	40
	Carbon-Johnson	18	27	50	19	28	40
	Green River-Dead Man	18	27	50	19	27	40
Gulf Coast	Wilcox	18	27	50	19	29	40
	Lower Wilcox	18	27	50	19	28	40
Appalachia	Pittsburgh	17	28	49	18	30	43
	Upper Freeport	17	28	49	18	29	43
	Lower Kittanning	18	30	50	20	32	46
	Pond Creek	17	29	49	19	30	43
	Fire Clay	17	29	50	18	30	44
	Pocohontas	17	28	49	18	30	42
Illinois	Springfield	18	29	50	20	32	46
	Herrin	17	29	50	18	31	45
	Danville	17	29	50	20	32	47

Table C113. Option 4 Methane mitigation costs for underground mines, $/ton of coal produced

Region	Coalfield	Longwall			Continuous		
		0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	19	26	51	20	28	47
	South Wasatch	19	26	51	20	27	47
	Yampa	19	26	51	21	28	47
	Henry Mountains	20	26	52	21	27	48
	San Juan	19	26	51	20	27	46
Rocky Mountains and Great Plains	Ashland	19	26	51	20	27	45
	Colstrip	19	26	51	20	27	45
	Decker	19	26	51	20	27	45
	Gillette	19	27	45	20	28	45
	Sheridan	19	27	45	20	28	45
	Williston-Beulah-Zap	19	27	45	20	28	45
	Williston-Hagel	19	27	45	20	28	45
	Williston-Hansen	19	27	45	20	28	45
	Williston-Harmon	19	27	45	21	28	45
	Carbon-Johnson	19	27	45	20	28	45
	Green River-Dead Man	19	27	45	21	28	45
Gulf Coast	Wilcox	19	27	46	20	28	46
	Lower Wilcox	19	27	45	20	28	45
Appalachia	Pittsburgh	19	27	46	20	29	42
	Upper Freeport	19	27	46	20	28	42
	Lower Kittanning	20	28	47	22	32	45
	Pond Creek	19	27	47	20	29	43
	Fire Clay	19	27	46	20	29	43
	Pocohontas	19	27	46	20	28	44
Illinois	Springfield	19	28	47	22	31	44
	Herrin	20	27	46	22	30	46
	Danville	20	28	47	22	31	45

C.11 Air Emissions Results

As discussed in Section 8, air emissions from mining are calculated. The tables in this section tabulate 5th – 95th percentile estimates.

Table C114 Calculated total suspended particulate emissions from underground mining (lb/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.0	0.0	0.1	0.0	0.0	0.1
	South Wasatch	0.0	0.0	0.1	0.0	0.0	0.1
	Yampa	0.0	0.0	0.1	0.0	0.0	0.1
	Henry Mountains	0.0	0.0	0.1	0.0	0.0	0.1
	San Juan	0.0	0.0	0.1	0.0	0.0	0.1
Rocky Mountains and Great Plains	Ashland	0.0	0.0	0.1	0.0	0.0	0.1
	Colstrip	0.0	0.0	0.1	0.0	0.0	0.1
	Decker	0.0	0.0	0.1	0.0	0.0	0.1
	Gillette	0.0	0.0	0.1	0.0	0.0	0.1
	Sheridan	0.0	0.0	0.1	0.0	0.0	0.1
	Williston-Beulah-Zap	0.0	0.0	0.1	0.0	0.0	0.1
	Williston-Hagel	0.0	0.0	0.1	0.0	0.0	0.1
	Williston-Hansen	0.0	0.0	0.1	0.0	0.0	0.1
	Williston-Harmon	0.0	0.0	0.1	0.0	0.0	0.1
	Carbon-Johnson	0.0	0.0	0.1	0.0	0.0	0.1
	Green River-Dead Man	0.0	0.0	0.1	0.0	0.0	0.1
Gulf Coast	Wilcox	0.0	0.0	0.1	0.0	0.0	0.1
	Lower Wilcox	0.0	0.0	0.1	0.0	0.0	0.1
Appalachia	Pittsburgh	0.0	0.0	0.1	0.0	0.0	0.1
	Upper Freeport	0.0	0.0	0.1	0.0	0.0	0.1
	Lower Kittanning	0.0	0.0	0.1	0.0	0.0	0.1
	Pond Creek	0.0	0.0	0.1	0.0	0.0	0.1
	Fire Clay	0.0	0.0	0.1	0.0	0.0	0.1
	Pocohontas	0.0	0.0	0.1	0.0	0.0	0.1
Illinois	Springfield	0.0	0.0	0.1	0.0	0.0	0.1
	Herrin	0.0	0.0	0.1	0.0	0.0	0.1
	Danville	0.0	0.0	0.1	0.0	0.0	0.1

Table C115 Calculated longwall NO_X emissions by source (lb/ton of coal produced)

			Total		*Coal Cleaning*		*Electricity Consumption*	
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	South Wasatch	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Yampa	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Henry Mountains	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	San Juan	0.2	0.2	0.2	0.2	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Colstrip	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Decker	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Gillette	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Sheridan	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Williston-Beulah-Zap	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Williston-Hagel	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Williston-Hansen	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Williston-Harmon	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Carbon-Johnson	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Green River-Dead Man	0.2	0.2	0.2	0.2	0.0	0.0	0.0
Gulf Coast	Wilcox	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Lower Wilcox	0.2	0.2	0.2	0.2	0.0	0.0	0.0
Appalachia	Pittsburgh	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Upper Freeport	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Lower Kittanning	0.2	0.2	0.2	0.2	0.0	0.0	0.1
	Pond Creek	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Fire Clay	0.2	0.2	0.2	0.2	0.0	0.0	0.0
	Pocohontas	0.2	0.2	0.2	0.2	0.0	0.0	0.0
Illinois	Springfield	0.2	0.2	0.2	0.2	0.0	0.0	0.1
	Herrin	0.2	0.2	0.2	0.2	0.0	0.0	0.1
	Danville	0.2	0.2	0.2	0.2	0.0	0.0	0.1

Table C116 Calculated longwall SO_2 emissions by source (lb/ton of coal produced)

			Total		*Coal Cleaning*		*Electricity Consumption*	
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	South Wasatch	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Yampa	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Henry Mountains	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	San Juan	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Colstrip	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Decker	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Gillette	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Sheridan	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Williston-Beulah-Zap	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Williston-Hagel	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Williston-Hansen	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Williston-Harmon	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Carbon-Johnson	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Green River-Dead Man	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
Gulf Coast	Wilcox	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
	Lower Wilcox	0.1	0.6	1.3	0.072-1.4	0.0	0.0	0.0
Appalachia	Pittsburgh	0.2	0.6	1.4	0.072-1.4	0.0	0.0	0.1
	Upper Freeport	0.2	0.6	1.3	0.072-1.4	0.0	0.0	0.1
	Lower Kittanning	0.2	0.7	1.4	0.072-1.4	0.1	0.1	0.2
	Pond Creek	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.1
	Fire Clay	0.2	0.6	1.3	0.072-1.4	0.0	0.0	0.1
	Pocohontas	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.1
Illinois	Springfield	0.2	0.7	1.4	0.072-1.4	0.0	0.1	0.2
	Herrin	0.2	0.7	1.4	0.072-1.4	0.0	0.1	0.2
	Danville	0.2	0.7	1.4	0.072-1.4	0.0	0.1	0.2

Table C117 Calculated longwall methane emissions (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Electricity Consumption*			*Coalbed Mining*	*Coalbed Postmining*
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95	Constant	Constant
Colorado Plateau	South Piceance	5	5	5	0.1	0.0	0.0	0.0	2.7	2.2
	South Wasatch	4	4	4	0.1	0.0	0.0	0.0	2.7	1.1
	Yampa	4	4	4	0.1	0.0	0.0	0.0	2.7	1.1
	Henry Mountains	4	4	4	0.1	0.0	0.0	0.0	2.7	1.1
	San Juan	4	4	4	0.1	0.0	0.0	0.0	2.7	1.2
Rocky Mountains and Great Plains	Ashland	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Colstrip	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Decker	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Gillette	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Sheridan	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Williston-Beulah-Zap	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Williston-Hagel	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Williston-Hansen	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Williston-Harmon	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Carbon-Johnson	3	3	3	0.1	0.0	0.0	0.0	2.7	0.2
	Green River-Dead Man	4	4	4	0.1	0.0	0.0	0.0	2.7	1.5
Gulf Coast	Wilcox	4	4	4	0.1	0.0	0.0	0.0	2.9	1.5
	Lower Wilcox	4	4	4	0.1	0.0	0.0	0.0	2.9	1.5
Appalachia	Pittsburgh	4	4	4	0.1	0.0	0.0	0.0	3.1	0.5
	Upper Freeport	4	4	4	0.1	0.0	0.0	0.0	3.1	0.5
	Lower Kittanning	4	4	4	0.1	0.0	0.0	0.0	3.1	0.5
	Pond Creek	4	5	8	0.1	0.0	0.0	0.0	3.1	2.6
	Fire Clay	4	5	7	0.1	0.0	0.0	0.0	3.1	2.6
	Pocohontas	4	6	8	0.1	0.0	0.0	0.0	3.1	2.6
Illinois	Springfield	2	2	2	0.1	0.0	0.0	0.0	1.6	0.7
	Herrin	2	2	2	0.1	0.0	0.0	0.0	1.6	0.7
	Danville	2	2	2	0.1	0.0	0.0	0.0	1.6	0.7

Table C118 Calculated longwall CO_2 emissions by source (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Electricity Consumption*		
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	33	35	43	30	3	5	13
	South Wasatch	32	34	38	30	2	4	8
	Yampa	33	37	40	30	3	7	10
	Henry Mountains	33	36	46	30	3	6	16
	San Juan	32	35	42	30	2	5	12
Rocky Mountains and Great Plains	Ashland	32	34	37	30	2	4	7
	Colstrip	32	34	37	30	2	4	7
	Decker	32	34	37	30	2	4	7
	Gillette	32	34	37	30	2	4	7
	Sheridan	32	34	37	30	2	4	7
	Williston-Beulah-Zap	32	34	38	30	2	4	8
	Williston-Hagel	32	34	39	30	2	4	9
	Williston-Hansen	32	35	38	30	2	5	8
	Williston-Harmon	32	34	38	30	2	4	8
	Carbon-Johnson	32	34	37	30	2	4	7
	Green River-Dead Man	32	35	38	30	2	5	8
Gulf Coast	Wilcox	31	33	40	30	1	3	10
	Lower Wilcox	32	33	40	30	2	3	10
Appalachia	Pittsburgh	33	37	45	30	3	7	15
	Upper Freeport	33	35	41	30	3	5	11
	Lower Kittanning	39	46	62	30	9	16	32
	Pond Creek	33	37	49	30	3	7	19
	Fire Clay	33	36	49	30	3	6	19
	Pocohontas	33	36	45	30	3	6	15
Illinois	Springfield	38	46	67	30	8	16	37
	Herrin	35	42	63	30	5	12	33
	Danville	38	47	61	30	8	17	31

Table C119 Calculated N_2O emissions from underground mining (lb/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.0	0.0	0.0	0.0	0.0	0.0
	South Wasatch	0.0	0.0	0.0	0.0	0.0	0.0
	Yampa	0.0	0.0	0.0	0.0	0.0	0.0
	Henry Mountains	0.0	0.0	0.0	0.0	0.0	0.0
	San Juan	0.0	0.0	0.0	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.0	0.0	0.0	0.0	0.0	0.0
	Colstrip	0.0	0.0	0.0	0.0	0.0	0.0
	Decker	0.0	0.0	0.0	0.0	0.0	0.0
	Gillette	0.0	0.0	0.0	0.0	0.0	0.0
	Sheridan	0.0	0.0	0.0	0.0	0.0	0.0
	Williston-Beulah-Zap	0.0	0.0	0.0	0.0	0.0	0.0
	Williston-Hagel	0.0	0.0	0.0	0.0	0.0	0.0
	Williston-Hansen	0.0	0.0	0.0	0.0	0.0	0.0
	Williston-Harmon	0.0	0.0	0.0	0.0	0.0	0.0
	Carbon-Johnson	0.0	0.0	0.0	0.0	0.0	0.0
	Green River-Dead Man	0.0	0.0	0.0	0.0	0.0	0.0
Gulf Coast	Wilcox	0.0	0.0	0.0	0.0	0.0	0.0
	Lower Wilcox	0.0	0.0	0.0	0.0	0.0	0.0
Appalachia	Pittsburgh	0.0	0.0	0.0	0.0	0.0	0.0
	Upper Freeport	0.0	0.0	0.0	0.0	0.0	0.0
	Lower Kittanning	0.0	0.0	0.0	0.0	0.0	0.0
	Pond Creek	0.0	0.0	0.0	0.0	0.0	0.0
	Fire Clay	0.0	0.0	0.0	0.0	0.0	0.0
	Pocohontas	0.0	0.0	0.0	0.0	0.0	0.0
Illinois	Springfield	0.0	0.0	0.0	0.0	0.0	0.0
	Herrin	0.0	0.0	0.0	0.0	0.0	0.0
	Danville	0.0	0.0	0.0	0.0	0.0	0.0

Table C120 Calculated greenhouse gas emissions from underground mining (lbCO_2e/ton of coal produced)

		Longwall			Continuous		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	South Piceance	137	140	148	141	146	161
	South Wasatch	114	115	119	117	121	125
	Yampa	114	119	122	118	128	137
	Henry Mountains	115	117	128	119	124	138
	San Juan	116	118	125	119	123	134
Rocky Mountains and Great Plains	Ashland	94	95	99	97	102	104
	Colstrip	94	96	99	97	106	108
	Decker	94	95	99	97	101	105
	Gillette	94	95	99	97	101	105
	Sheridan	94	95	99	97	101	104
	Williston-Beulah-Zap	94	96	100	98	102	107
	Williston-Hagel	94	96	101	98	103	107
	Williston-Hansen	94	97	100	97	103	113
	Williston-Harmon	94	96	100	97	102	105
	Carbon-Johnson	94	95	99	97	101	106
	Green River-Dead Man	121	124	127	125	130	134
Gulf Coast	Wilcox	126	127	134	128	131	141
	Lower Wilcox	126	127	135	128	131	141
Appalachia	Pittsburgh	111	114	122	113	122	134
	Upper Freeport	110	112	118	113	117	125
	Lower Kittanning	116	123	140	122	140	156
	Pond Creek	125	156	197	130	163	207
	Fire Clay	123	153	199	127	164	201
	Pocohontas	121	168	196	130	179	201
Illinois	Springfield	89	96	118	96	110	125
	Herrin	86	93	114	89	112	134
	Danville	89	98	112	97	108	129

Table C121 Calculated continuous mine NO_X emissions by source (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Electricity Consumption*		
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	South Wasatch	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Yampa	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Henry Mountains	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	San Juan	0.2	0.2	0.2	0.16	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Colstrip	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Decker	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Gillette	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Sheridan	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Williston-Beulah-Zap	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Williston-Hagel	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Williston-Hansen	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Williston-Harmon	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Carbon-Johnson	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Green River-Dead Man	0.2	0.2	0.2	0.16	0.0	0.0	0.0
Gulf Coast	Wilcox	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Lower Wilcox	0.2	0.2	0.2	0.16	0.0	0.0	0.0
Appalachia	Pittsburgh	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Upper Freeport	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Lower Kittanning	0.2	0.2	0.2	0.16	0.0	0.1	0.1
	Pond Creek	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Fire Clay	0.2	0.2	0.2	0.16	0.0	0.0	0.0
	Pocohontas	0.2	0.2	0.2	0.16	0.0	0.0	0.0
Illinois	Springfield	0.2	0.2	0.2	0.16	0.0	0.1	0.1
	Herrin	0.2	0.2	0.3	0.16	0.0	0.1	0.1
	Danville	0.2	0.2	0.2	0.16	0.0	0.0	0.1

Table C122 Calculated continuous SO_2 emissions by source (lb/ton of coal produced)

			Total		*Coal Cleaning*	*Electricity Consumption*		
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
	South Wasatch	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
	Yampa	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
	Henry Mountains	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
	San Juan	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Colstrip	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Decker	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Gillette	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Sheridan	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Williston-Beulah-Zap	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Williston-Hagel	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Williston-Hansen	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.1
	Williston-Harmon	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Carbon-Johnson	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
	Green River-Dead Man	0.2	0.7	1.4	0.072-1.4	0.0	0.0	0.0
Gulf Coast	Wilcox	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
	Lower Wilcox	0.2	0.7	1.3	0.072-1.4	0.0	0.0	0.0
Appalachia	Pittsburgh	0.3	0.8	1.4	0.072-1.4	0.0	0.1	0.2
	Upper Freeport	0.2	0.8	1.4	0.072-1.4	0.0	0.1	0.1
	Lower Kittanning	0.3	0.9	1.5	0.072-1.4	0.1	0.2	0.3
	Pond Creek	0.2	0.8	1.4	0.072-1.4	0.0	0.1	0.2
	Fire Clay	0.2	0.8	1.4	0.072-1.4	0.0	0.1	0.2
	Pocohontas	0.2	0.8	1.4	0.072-1.4	0.0	0.1	0.2
Illinois	Springfield	0.3	0.9	1.5	0.072-1.4	0.1	0.2	0.3
	Herrin	0.3	0.8	1.4	0.072-1.4	0.0	0.2	0.3
	Danville	0.3	0.9	1.5	0.072-1.4	0.1	0.2	0.3

Table C123 Calculated continuous mine methane emissions (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Electricity Consumption*			*Coalbed Mining*	*Coalbed Postmining*
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95	Constant	Constant
Colorado Plateau	South Piceance	5	5	5	0.10	0.0	0.0	0.0	2.7	2.2
	South Wasatch	4	4	4	0.10	0.0	0.0	0.0	2.7	1.1
	Yampa	4	4	4	0.10	0.0	0.0	0.0	2.7	1.1
	Henry Mountains	4	4	4	0.10	0.0	0.0	0.0	2.7	1.1
	San Juan	4	4	4	0.10	0.0	0.0	0.0	2.7	1.2
Rocky Mountains and Great Plains	Ashland	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Colstrip	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Decker	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Gillette	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Sheridan	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Williston-Beulah-Zap	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Williston-Hagel	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Williston-Hansen	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Williston-Harmon	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Carbon-Johnson	3	3	3	0.10	0.0	0.0	0.0	2.7	0.2
	Green River-Dead Man	4	4	4	0.10	0.0	0.0	0.0	2.7	1.5
Gulf Coast	Wilcox	4	4	4	0.10	0.0	0.0	0.0	2.9	1.5
	Lower Wilcox	4	4	4	0.10	0.0	0.0	0.0	2.9	1.5
Appalachia	Pittsburgh	4	4	4	0.10	0.0	0.0	0.0	3.1	0.5
	Upper Freeport	4	4	4	0.10	0.0	0.0	0.0	3.1	0.5
	Lower Kittanning	4	4	4	0.10	0.0	0.0	0.0	3.1	0.5
	Pond Creek	4	6	8	0.10	0.0	0.0	0.0	3.1	2.6
	Fire Clay	4	6	8	0.10	0.0	0.0	0.0	3.1	2.6
	Pocohontas	4	6	8	0.10	0.0	0.0	0.0	3.1	2.6
Illinois	Springfield	2	2	2	0.10	0.0	0.0	0.0	1.6	0.7
	Herrin	2	2	2	0.10	0.0	0.0	0.0	1.6	0.7
	Danville	2	2	2	0.10	0.0	0.0	0.0	1.6	0.7

Table C124 Calculated continuous mine CO_2 emissions by source (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Electricity Consumption*		
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95
Colorado Plateau	South Piceance	36	42	56	30	6	12	26
	South Wasatch	36	39	44	30	6	9	14
	Yampa	36	46	55	30	6	16	25
	Henry Mountains	37	42	56	30	7	12	26
	San Juan	36	40	51	30	6	10	21
Rocky Mountains and Great Plains	Ashland	35	40	42	30	5	10	12
	Colstrip	36	44	46	30	6	14	16
	Decker	35	40	43	30	5	10	13
	Gillette	36	40	43	30	36	40	43
	Sheridan	36	40	42	30	36	40	42
	Williston-Beulah-Zap	36	40	45	30	36	40	45
	Williston-Hagel	36	42	45	30	36	42	45
	Williston-Hansen	36	41	51	30	36	41	51
	Williston-Harmon	36	40	44	30	36	40	44
	Carbon-Johnson	36	40	44	30	36	40	44
	Green River-Dead Man	36	41	45	30	36	41	45
Gulf Coast	Wilcox	34	37	46	30	34	37	46
	Lower Wilcox	34	37	47	30	34	37	47
Appalachia	Pittsburgh	36	45	56	30	6	15	26
	Upper Freeport	36	40	48	30	6	10	18
	Lower Kittanning	45	63	78	30	15	33	48
	Pond Creek	37	45	55	30	7	15	25
	Fire Clay	36	46	55	30	6	16	25
	Pocohontas	36	46	56	30	6	16	26
Illinois	Springfield	46	59	74	30	16	29	44
	Herrin	38	61	83	30	8	31	53
	Danville	46	58	78	30	16	28	48

Table C125 Calculated surface mine total suspended particulate emissions (lb/ton of coal produced)

		Total			*Blasting*			*Truck Loading*			*Vehicle Traffic*			*Bulldozing*			*Coal Cleaning*			*Vehicle Fuel Use*		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0	2	5	0	0	0	0	1	2	0	1	4	0	0	0	0	0	0	0	0	0
	Deserado	4	15	43	0	0	0	0	1	2	3	15	42	0	0	0	0	0	0	0	0	0
	South Piceance	5	18	128	0	0	0	0	1	2	5	17	127	0	0	0	0	0	0	0	0	0
	South Wasatch	4	18	48	0	0	0	0	1	2	3	16	47	0	0	0	0	0	0	0	0	0
	Yampa	6	24	77	0	0	1	0	1	2	4	24	76	0	0	0	0	0	0	0	0	0
	Henry Mountains	7	19	55	0	0	0	0	1	2	6	19	54	0	0	0	0	0	0	0	0	0
	San Juan	7	20	57	0	0	1	0	1	2	6	18	56	0	0	0	0	0	0	0	0	0
Rocky Mountains and Great Plains	Ashland	2	5	17	0	0	0	0	0	0	1	5	17	0	0	0	0	0	0	0	0	0
	Colstrip	2	7	23	0	0	0	0	0	0	1	7	23	0	0	0	0	0	0	0	0	0
	Decker	0	2	6	0	0	0	0	0	0	0	1	6	0	0	0	0	0	0	0	0	0
	Gillette	1	2	7	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Sheridan	1	2	9	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Williston-Beulah-Zap	1	5	12	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Williston-Hagel	1	3	11	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Williston-Hansen	1	5	19	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Williston-Harmon	1	2	11	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Hanna-Ferris 23, 25,31,50,65	12	39	109	0	0	1	0	0	0	0	2	7	0	0	1	0	0	0	0	0	0
	Hanna-Hanna 77,78,79,81	1	4	15	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Carbon-Johnson	2	8	16	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
	Green River-Dead Man	1	3	9	0	0	0	0	0	0	0	2	7	0	0	0	0	0	0	0	0	0
Gulf Coa	Wilcox	1	4	26	0	0	0	0	0	0	1	4	26	0	0	0	0	0	0	0	0	0
	Lower Wilcox	1	4	17	0	0	0	0	0	0	1	3	17	0	0	0	0	0	0	0	0	0
Appalachia	Pittsburgh	9	26	77	0	0	0	2	5	22	2	16	67	0	0	0	0	0	0	0	0	0
	Upper Freeport	9	26	65	0	0	0	2	5	22	3	17	52	0	0	0	0	0	0	0	0	0
	Lower Kittanning	47	123	313	0	1	2	2	5	22	39	114	293	0	0	1	0	0	0	0	0	1
	Pond Creek	9	43	156	0	0	1	2	5	22	6	31	146	0	0	0	0	0	0	0	0	0
	Fire Clay	11	28	99	0	0	0	2	5	22	6	24	80	0	0	0	0	0	0	0	0	0
	Pocohontas	13	43	146	0	0	1	2	5	22	6	31	135	0	0	0	0	0	0	0	0	0
Illinois	Springfield	12	60	190	0	0	1	1	1	5	11	58	188	0	0	1	0	0	0	0	0	1
	Herrin	11	39	110	0	0	1	1	1	5	9	38	108	0	0	1	0	0	0	0	0	1
	Danville	17	58	187	0	0	1	1	1	5	14	55	186	0	0	1	0	0	0	0	0	0

Table C126 Calculated surface mine CO emissions (lb/ton of coal produced)

Region	Coalfield	Total			Vehicle Fuel Use			ANFO Explosion		
		0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Deserado	0.0	0.2	0.9	0.0	0.0	0.0	0.0	0.2	0.9
	South Piceance	0.2	0.6	5.1	0.0	0.0	0.0	0.2	0.6	5.1
	South Wasatch	0.1	0.5	2.7	0.0	0.0	0.0	0.1	0.5	2.7
	Yampa	0.1	0.8	3.5	0.0	0.0	0.0	0.1	0.8	3.5
	Henry Mountains	0.1	0.7	4.3	0.0	0.0	0.0	0.1	0.7	4.3
	San Juan	0.1	0.8	3.7	0.0	0.0	0.0	0.1	0.8	3.7
Rocky Mountains and Great Plains	Ashland	0.0	0.2	1.8	0.0	0.0	0.0	0.0	0.2	1.8
	Colstrip	0.0	0.2	1.2	0.0	0.0	0.0	0.0	0.2	1.2
	Decker	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2
	Gillette	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.6
	Sheridan	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.1	0.4
	Williston-Beulah-Zap	0.0	0.2	1.0	0.0	0.0	0.0	0.0	0.2	1.0
	Williston-Hagel	0.0	0.1	0.7	0.0	0.0	0.0	0.0	0.1	0.7
	Williston-Hansen	0.0	0.2	1.6	0.0	0.0	0.0	0.0	0.2	1.6
	Williston-Harmon	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.1	0.5
	Hanna-Ferris 23, 25,31,50,65	0.0	0.2	1.0	0.0	0.0	0.0	0.0	0.2	1.0
	Hanna-Hanna 77,78,79,81	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2
	Carbon-Johnson	0.0	0.2	0.9	0.0	0.0	0.0	0.0	0.2	0.9
	Green River-Dead Man	0.0	0.1	0.5	0.0	0.0	0.0	0.0	0.1	0.5
Gulf Coast	Wilcox	0.0	0.2	1.3	0.0	0.0	0.0	0.0	0.2	1.3
	Lower Wilcox	0.0	0.1	1.0	0.0	0.0	0.0	0.0	0.1	1.0
Appalachia	Pittsburgh	0.0	0.6	3.1	0.0	0.0	0.0	0.0	0.6	3.1
	Upper Freeport	0.1	0.6	2.4	0.0	0.0	0.0	0.1	0.6	2.4
	Lower Kittanning	0.7	5.8	22.6	0.0	0.0	0.0	0.7	5.8	22.6
	Pond Creek	0.2	1.1	6.7	0.0	0.0	0.0	0.2	1.1	6.7
	Fire Clay	0.1	0.9	3.9	0.0	0.0	0.0	0.1	0.9	3.9
	Pocohontas	0.1	1.2	7.0	0.0	0.0	0.0	0.1	1.2	7.0
Illinois	Springfield	0.3	1.8	12.2	0.0	0.0	0.0	0.3	1.8	12.2
	Herrin	0.2	1.2	9.3	0.0	0.0	0.0	0.2	1.2	9.3
	Danville	0.3	2.5	9.0	0.0	0.0	0.0	0.3	2.5	9.0

Table C127 Calculated surface mine NO_X emissions (lb/ton of coal produced)

		Total			*Coal Cleaning*	*ANFO Explosion*			*Vehicle Fuel Use*		
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Deserado	0.2	0.2	0.4	0.2	0.0	0.1	0.3	0.0	0.0	0.0
	South Piceance	0.2	0.3	1.3	0.2	0.0	0.2	1.1	0.0	0.0	0.0
	South Wasatch	0.2	0.3	0.8	0.2	0.0	0.2	0.6	0.0	0.0	0.0
	Yampa	0.2	0.4	1.3	0.2	0.0	0.2	1.2	0.0	0.0	0.0
	Henry Mountains	0.2	0.4	1.4	0.2	0.0	0.2	1.2	0.0	0.0	0.0
	San Juan	0.2	0.4	1.1	0.2	0.0	0.2	1.0	0.0	0.0	0.0
Rocky Mountains and Great Plains	Ashland	0.2	0.2	0.5	0.2	0.0	0.0	0.4	0.0	0.0	0.0
	Colstrip	0.2	0.2	0.5	0.2	0.0	0.1	0.3	0.0	0.0	0.0
	Decker	0.2	0.2	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0
	Gillette	0.2	0.2	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0
	Sheridan	0.2	0.2	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0
	Williston-Beulah-Zap	0.2	0.2	0.4	0.2	0.0	0.0	0.3	0.0	0.0	0.0
	Williston-Hagel	0.2	0.2	0.3	0.2	0.0	0.0	0.2	0.0	0.0	0.0
	Williston-Hansen	0.2	0.2	0.5	0.2	0.0	0.0	0.3	0.0	0.0	0.0
	Williston-Harmon	0.2	0.2	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0
	Hanna-Ferris 23, 25,31,50,65	0.2	0.2	0.4	0.2	0.0	0.0	0.2	0.0	0.0	0.0
	Hanna-Hanna 77,78,79,81	0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
	Carbon-Johnson	0.2	0.2	0.4	0.2	0.0	0.1	0.3	0.0	0.0	0.0
	Green River-Dead Man	0.2	0.2	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0
Gulf Coast	Wilcox	0.2	0.2	0.6	0.2	0.0	0.0	0.4	0.0	0.0	0.0
	Lower Wilcox	0.2	0.2	0.4	0.2	0.0	0.0	0.2	0.0	0.0	0.0
Appalachia	Pittsburgh	0.2	0.3	1.2	0.2	0.0	0.2	1.0	0.0	0.0	0.0
	Upper Freeport	0.2	0.3	0.7	0.2	0.0	0.1	0.5	0.0	0.0	0.0
	Lower Kittanning	0.3	1.4	5.2	0.2	0.2	1.2	5.0	0.0	0.0	0.0
	Pond Creek	0.2	0.5	1.5	0.2	0.0	0.3	1.4	0.0	0.0	0.0
	Fire Clay	0.2	0.4	1.2	0.2	0.0	0.2	1.0	0.0	0.0	0.0
	Pocohontas	0.2	0.4	2.5	0.2	0.0	0.3	2.3	0.0	0.0	0.0
Illinois	Springfield	0.2	0.6	2.1	0.2	0.1	0.5	1.9	0.0	0.0	0.0
	Herrin	0.2	0.5	1.8	0.2	0.1	0.3	1.6	0.0	0.0	0.0
	Danville	0.2	0.8	2.5	0.2	0.1	0.6	2.3	0.0	0.0	0.0

Table C128 Calculated surface mine SO_2 emissions (lb/ton of coal produced)

		Total			*Coal Cleaning*			*ANFO Explosion*		
Region	Coalfield	0.05	0.5	0.95	0.05	0.5	0.95	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Deserado	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	South Piceance	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.2
	South Wasatch	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	Yampa	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	Henry Mountains	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	San Juan	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
Rocky Mountains and Great Plains	Ashland	0.2	0.8	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Colstrip	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.1
	Decker	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Gillette	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Sheridan	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Williston-Beulah-Zap	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Williston-Hagel	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Williston-Hansen	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Williston-Harmon	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Hanna-Ferris 23, 25,31,50,65	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Hanna-Hanna 77,78,79,81	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Carbon-Johnson	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Green River-Dead Man	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
Gulf Coast	Wilcox	0.2	0.8	1.3	0.2	0.7	1.3	0.0	0.0	0.0
	Lower Wilcox	0.2	0.7	1.3	0.2	0.7	1.3	0.0	0.0	0.0
Appalachia	Pittsburgh	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	Upper Freeport	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	Lower Kittanning	0.3	0.9	1.6	0.2	0.7	1.3	0.0	0.1	0.6
	Pond Creek	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.2
	Fire Clay	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.1
	Pocohontas	0.2	0.9	1.4	0.2	0.7	1.3	0.0	0.0	0.3
Illinois	Springfield	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.1	0.2
	Herrin	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.0	0.2
	Danville	0.2	0.8	1.4	0.2	0.7	1.3	0.0	0.1	0.2

Table C129 Calculated surface mine methane emissions (lb/ton of coal produced)

		Total			*Coal Cleaning*	*Vehicle Fuel Use*			*Coalbed Mining*	*Coalbed Postmining*
Region	Coalfield	0.05	0.5	0.95	Constant	0.05	0.5	0.95	Constant	Constant
Colorado Plateau	Danforth Hills	2.8	2.8	2.8	0.1	0.0	0.0	0.0	2.3	0.4
	Deserado	1.4	1.4	1.7	0.1	0.0	0.0	0.2	1.1	0.2
	South Piceance	2.8	2.9	3.6	0.1	0.0	0.1	0.6	2.3	0.4
	South Wasatch	1.4	1.5	1.9	0.1	0.0	0.2	0.6	1.1	0.2
	Yampa	1.4	1.6	2.7	0.1	0.0	0.2	1.2	1.1	0.2
	Henry Mountains	1.4	1.5	1.9	0.1	0.0	0.1	0.7	1.1	0.2
	San Juan	0.7	0.9	1.5	0.1	0.0	0.1	0.9	0.5	0.1
Rocky Mountains and Great Plains	Ashland	0.6	0.6	0.9	0.1	0.0	0.0	0.2	0.4	0.1
	Colstrip	0.6	0.6	0.7	0.1	0.0	0.0	0.2	0.4	0.1
	Decker	0.6	0.6	0.6	0.1	0.0	0.0	0.0	0.4	0.1
	Gillette	0.6	0.6	0.6	0.1	0.0	0.0	0.1	0.4	0.1
	Sheridan	0.6	0.6	0.6	0.1	0.0	0.0	0.1	0.4	0.1
	Williston-Beulah-Zap	0.6	0.6	0.6	0.1	0.0	0.0	0.0	0.4	0.1
	Williston-Hagel	0.6	0.6	0.6	0.1	0.0	0.0	0.0	0.4	0.1
	Williston-Hansen	0.6	0.6	0.6	0.1	0.0	0.0	0.1	0.4	0.1
	Williston-Harmon	0.6	0.6	0.6	0.1	0.0	0.0	0.0	0.4	0.1
	Hanna-Ferris 23, 25,31,50,65	0.6	0.6	0.6	0.1	0.0	0.0	0.1	0.4	0.1
	Hanna-Hanna 77,78,79,81	0.6	0.6	0.6	0.1	0.0	0.0	0.0	0.4	0.1
	Carbon-Johnson	0.6	0.6	0.8	0.1	0.0	0.1	0.2	0.4	0.1
	Green River-Dead Man	2.8	2.8	2.8	0.1	0.0	0.0	0.0	2.3	0.4
Gulf Coast	Wilcox	2.8	2.8	2.8	0.1	0.0	0.0	0.0	2.3	0.4
	Lower Wilcox	2.8	2.8	2.8	0.1	0.0	0.0	0.0	2.3	0.4
Appalachia	Pittsburgh	4.9	5.0	5.6	0.1	0.0	0.0	0.6	4.2	0.7
	Upper Freeport	4.9	5.0	5.3	0.1	0.0	0.0	0.4	2.3	0.4
	Lower Kittanning	5.4	6.5	10.4	0.1	0.6	1.6	6.4	4.2	0.7
	Pond Creek	2.1	2.3	3.3	0.1	0.0	0.2	2.1	0.4	0.1
	Fire Clay	2.1	2.2	3.0	0.1	0.0	0.1	0.5	1.8	0.3
	Pocohontas	2.2	2.4	3.5	0.1	0.0	0.3	1.5	1.8	0.3
Illinois	Springfield	2.9	3.1	4.4	0.1	0.0	0.2	1.3	2.4	0.4
	Herrin	2.9	3.0	4.3	0.1	0.0	0.1	0.6	2.4	0.4
	Danville	2.9	3.1	4.5	0.1	0.0	0.2	1.0	2.4	0.4

Table C130 Calculated surface mine CO emissions (lb/ton of coal produced)

Region	Coalfield	*Total* 0.05	*Total* 0.5	*Total* 0.95	*Coal Cleaning* Constant	*Vehicle Fuel Use* 0.05	*Vehicle Fuel Use* 0.5	*Vehicle Fuel Use* 0.95
Colorado Plateau	Danforth Hills	30.0	30.0	30.0	30.0	0.0	0.0	0.0
	Deserado	30.0	30.0	30.3	30.0	0.0	0.0	0.3
	South Piceance	30.0	30.1	30.8	30.0	0.0	0.1	0.8
	South Wasatch	30.0	30.2	30.7	30.0	0.0	0.2	0.7
	Yampa	30.0	30.2	31.5	30.0	0.0	0.2	1.5
	Henry Mountains	30.0	30.1	30.8	30.0	0.0	0.1	0.8
	San Juan	30.0	30.2	31.0	30.0	0.0	0.2	1.0
Rocky Mountains and Great Plains	Ashland	30.0	30.0	30.2	30.0	0.0	0.0	0.2
	Colstrip	30.0	30.0	30.3	30.0	0.0	0.0	0.3
	Decker	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Gillette	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Sheridan	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Williston-Beulah-Zap	30.0	30.0	30.0	30.0	0.0	0.0	0.0
	Williston-Hagel	30.0	30.0	30.0	30.0	0.0	0.0	0.0
	Williston-Hansen	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Williston-Harmon	30.0	30.0	30.0	30.0	0.0	0.0	0.0
	Hanna-Ferris 23, 25,31,50,65	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Hanna-Hanna 77,78,79,81	30.0	30.0	30.0	30.0	0.0	0.0	0.0
	Carbon-Johnson	30.0	30.1	30.4	30.0	0.0	0.1	0.4
	Green River-Dead Man	30.0	30.0	30.0	30.0	0.0	0.0	0.0
Gulf Coast	Wilcox	30.0	30.0	30.1	30.0	0.0	0.0	0.1
	Lower Wilcox	30.0	30.0	30.0	30.0	0.0	0.0	0.0
Appalachia	Pittsburgh	30.0	30.0	30.8	30.0	0.0	0.0	0.8
	Upper Freeport	30.0	30.1	30.4	30.0	0.0	0.1	0.4
	Lower Kittanning	30.7	31.9	36.1	30.0	0.7	1.9	6.1
	Pond Creek	30.0	30.2	32.2	30.0	0.0	0.2	2.2
	Fire Clay	30.0	30.1	30.5	30.0	0.0	0.1	0.5
	Pocohontas	30.0	30.3	31.4	30.0	0.0	0.3	1.4
Illinois	Springfield	30.0	30.2	31.7	30.0	0.0	0.2	1.7
	Herrin	30.0	30.1	30.9	30.0	0.0	0.1	0.9
	Danville	30.0	30.2	31.8	30.0	0.0	0.2	1.8

Table C131 Calculated surface mine N_2O emissions (lb/ton of produced coal)

Region	Coalfield	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	0.0	0.0	0.0
	Deserado	0.0	0.0	0.2
	South Piceance	0.0	0.1	0.7
	South Wasatch	0.0	0.1	0.5
	Yampa	0.0	0.2	1.0
	Henry Mountains	0.0	0.1	1.0
	San Juan	0.0	0.1	0.8
Rocky Mountains and Great Plains	Ashland	0.0	0.0	0.2
	Colstrip	0.0	0.0	0.2
	Decker	0.0	0.0	0.1
	Gillette	0.0	0.0	0.1
	Sheridan	0.0	0.0	0.1
	Williston-Beulah-Zap	0.0	0.0	0.1
	Williston-Hagel	0.0	0.0	0.0
	Williston-Hansen	0.0	0.0	0.1
	Williston-Harmon	0.0	0.0	0.0
	Hanna-Ferris 23, 25,31,50,65	0.0	0.0	0.1
	Hanna-Hanna 77,78,79,81	0.0	0.0	0.0
	Carbon-Johnson	0.0	0.1	0.2
	Green River-Dead Man	0.0	0.0	0.0
Gulf Coast	Wilcox	0.0	0.0	0.0
	Lower Wilcox	0.0	0.0	0.0
Appalachia	Pittsburgh	0.0	0.0	0.6
	Upper Freeport	0.0	0.0	0.5
	Lower Kittanning	0.6	1.8	3.5
	Pond Creek	0.0	0.2	1.5
	Fire Clay	0.0	0.1	0.5
	Pocohontas	0.0	0.3	1.2
Illinois	Springfield	0.0	0.2	1.8
	Herrin	0.0	0.1	0.7
	Danville	0.0	0.2	1.5

Table C132 Calculated surface mine greenhouse gas emissions (lbCO$_2$e/ton of coal produced)

Region	Coalfield	0.05	0.5	0.95
Colorado Plateau	Danforth Hills	88.8	88.9	89.9
	Deserado	59.7	67.0	146.4
	South Piceance	91.5	131.6	345.2
	South Wasatch	61.7	104.9	221.2
	Yampa	63.5	122.9	490.4
	Henry Mountains	60.9	94.4	236.0
	San Juan	48.5	96.9	327.8
Rocky Mountains and Great Plains	Ashland	42.4	53.4	142.6
	Colstrip	42.2	51.7	102.2
	Decker	41.7	42.3	50.0
	Gillette	41.8	44.7	62.6
	Sheridan	41.9	45.0	68.5
	Williston-Beulah-Zap	41.8	44.3	59.3
	Williston-Hagel	41.7	42.4	51.3
	Williston-Hansen	41.8	44.9	62.2
	Williston-Harmon	41.7	42.4	50.5
	Hanna-Ferris 23, 25,31,50,65	43.2	50.5	79.2
	Hanna-Hanna 77,78,79,81	41.9	44.5	60.4
	Carbon-Johnson	42.2	57.4	169.2
	Green River-Dead Man	88.9	89.4	99.4
Gulf Coast	Wilcox	89.0	89.8	99.5
	Lower Wilcox	88.9	90.1	100.0
Appalachia	Pittsburgh	134.2	144.1	339.0
	Upper Freeport	134.2	148.1	253.9
	Lower Kittanning	300.0	642.9	1949.2
	Pond Creek	77.4	132.0	456.6
	Fire Clay	76.3	97.9	346.8
	Pocohontas	82.4	150.2	543.3
Illinois	Springfield	95.9	147.0	579.3
	Herrin	92.6	133.3	555.1
	Danville	94.7	149.1	619.6

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