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FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-13105

ArchCoal

Arch Coal, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**43-0921172** (I.R.S. Employer Identification Number)
One CityPlace Drive, Ste. 300, St. Louis, Missouri (Address of principal executive offices)	**63141** (Zip code)

Registrant's telephone number, including area code: **(314) 994-2700**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☒

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such filed). Yes ☒ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ☒

The aggregate market value of the voting stock held by non-affiliates of the registrant (excluding outstanding shares beneficially owned by directors, officers and treasury shares) as of June 30, 2012 was approximately $1.4 billion.

On February 15, 2013, 212,246,799 shares of the company's common stock, par value $0.01 per share, were outstanding.

Portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the 2013 annual stockholders' meeting to be held on April 25, 2013 are incorporated by reference into Part III of this Form 10-K.

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If you are not familiar with any of the mining terms used in this report, we have provided explanations of many of them under the caption "Glossary of Selected Mining Terms" on page 32 of this report. Unless the context otherwise requires, all references in this report to "Arch," "we," "us," or "our" are to Arch Coal, Inc. and its subsidiaries.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This report contains forward-looking statements, within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, such as our expected future business and financial performance, and are intended to come within the safe harbor protections provided by those sections. The words "anticipates," "believes," "could," "estimates," "expects," "intends," "may," "plans," "predicts," "projects," "seeks," "should," "will" or other comparable words and phrases identify forward-looking statements, which speak only as of the date of this report. Forward-looking statements by their nature address matters that are, to different degrees, uncertain. Actual results may vary significantly from those anticipated due to many factors, including:

- market demand for coal and electricity;
- geologic conditions, weather and other inherent risks of coal mining that are beyond our control;
- competition, both within our industry and with producers of competing energy sources;
- excess production and production capacity;
- our ability to acquire or develop coal reserves in an economically feasible manner;
- inaccuracies in our estimates of our coal reserves;
- availability and price of mining and other industrial supplies;
- availability of skilled employees and other workforce factors;
- disruptions in the quantities of coal produced by our contract mine operators;
- our ability to collect payments from our customers;
- defects in title or the loss of a leasehold interest;
- railroad, barge, truck and other transportation performance and costs;
- our ability to successfully integrate the operations that we acquire;
- our ability to secure new coal supply arrangements or to renew existing coal supply arrangements;
- our relationships with, and other conditions affecting, our customers;
- the deferral of contracted shipments of coal by our customers;
- our ability to service our outstanding indebtedness;
- our ability to comply with the restrictions imposed by our credit facility and other financing arrangements;
- the availability and cost of surety bonds;
- our ability to manage the market and other risks associated with certain trading and other asset optimization strategies;
- terrorist attacks, military action or war;
- our ability to obtain and renew various permits, including permits authorizing the disposition of certain mining waste;

- existing and future legislation and regulations affecting both our coal mining operations and our customers' coal usage, governmental policies and taxes, including those aimed at reducing emissions of elements such as mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases;

- the accuracy of our estimates of reclamation and other mine closure obligations;

- the existence of hazardous substances or other environmental contamination on property owned or used by us; and

- other factors, including those discussed in Legal Proceedings, set forth in Item 3 of this report and Risk Factors, set forth in Item 1A of this report.

All forward-looking statements in this report, as well as all other written and oral forward-looking statements attributable to us or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements contained in this section and elsewhere in this report. These factors are not necessarily all of the important factors that could affect us. These risks and uncertainties, as well as other risks of which we are not aware or which we currently do not believe to be material, may cause our actual future results to be materially different than those expressed in our forward-looking statements. These forward-looking statements speak only as of the date on which such statements were made, and we do not undertake to update our forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by the federal securities law.

PART I

ITEM 1. BUSINESS.

Introduction

We are one of the world's largest coal producers. For the year ended December 31, 2012 we sold approximately 140.8 million tons of coal, including approximately 4.3 million tons of coal we purchased from third parties, representing roughly 14% of the 2012 U.S. coal supply. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2012, we operated, or contracted out the operation of, 32 active mines located in each of the major coal-producing regions of the United States. The locations of our mines and access to export facilities enable us to ship coal worldwide.

Our History

We were organized in Delaware in 1969 as Arch Mineral Corporation. In July 1997, we merged with Ashland Coal, Inc., a subsidiary of Ashland Inc. that was formed in 1975. As a result of the merger, we became one of the largest producers of low-sulfur coal in the eastern United States.

In June 1998, we expanded into the western United States when we acquired the coal assets of Atlantic Richfield Company, which we refer to as ARCO. This acquisition included the Black Thunder and Coal Creek mines in the Powder River Basin of Wyoming, the West Elk mine in Colorado and a 65% interest in Canyon Fuel Company, which operated three mines in Utah. In October 1998, we acquired a leasehold interest in the Thundercloud reserve, a 412-million-ton federal reserve tract adjacent to the Black Thunder mine.

In July 2004, we acquired the remaining 35% interest in Canyon Fuel Company. In August 2004, we acquired Triton Coal Company's North Rochelle mine adjacent to our Black Thunder operation. In September 2004, we acquired a leasehold interest in the Little Thunder reserve, a 719-million-ton federal reserve tract adjacent to the Black Thunder mine.

In December 2005, we sold the stock of Hobet Mining, Inc., Apogee Coal Company and Catenary Coal Company and their four associated mining complexes (Hobet 21, Arch of West Virginia, Samples and Campbells

Creek) and approximately 455.0 million tons of coal reserves in Central Appalachia to Magnum Coal Company, which was subsequently acquired by Patriot Coal Corporation.

On October 1, 2009, we acquired Rio Tinto's Jacobs Ranch mine complex in the Powder River Basin of Wyoming, which included 345 million tons of low-cost, low-sulfur coal reserves, and integrated it into the Black Thunder mine.

On June 15, 2011, we acquired International Coal Group, Inc., which owned and operated mines primarily in the Appalachian Region of the United States.

Coal Characteristics

End users generally characterize coal as steam coal or metallurgical coal. Heat value, sulfur, ash, moisture content, and volatility, in the case of metallurgical coal, are important variables in the marketing and transportation of coal. These characteristics help producers determine the best end use of a particular type of coal. The following is a description of these general coal characteristics:

Heat Value. In general, the carbon content of coal supplies most of its heating value, but other factors also influence the amount of energy it contains per unit of weight. The heat value of coal is commonly measured in Btus. Coal is generally classified into four categories, lignite, subbituminous, bituminous and anthracite, reflecting the progressive response of individual deposits of coal to increasing heat and pressure. Anthracite is coal with the highest carbon content and, therefore, the highest heat value, nearing 15,000 Btus per pound. Bituminous coal, used primarily to generate electricity and to make coke for the steel industry, has a heat value ranging between 10,500 and 15,500 Btus per pound. Subbituminous coal ranges from 8,300 to 13,000 Btus per pound and is generally used for electric power generation. Lignite coal is a geologically young coal which has the lowest carbon content and a heat value ranging between 4,000 and 8,300 Btus per pound.

Sulfur Content. Federal and state environmental regulations, including regulations that limit the amount of sulfur dioxide that may be emitted as a result of combustion, have affected and may continue to affect the demand for certain types of coal. The sulfur content of coal can vary from seam to seam and within a single seam. The chemical composition and concentration of sulfur in coal affects the amount of sulfur dioxide produced in combustion. Coal-fueled power plants can comply with sulfur dioxide emission regulations by burning coal with low sulfur content, blending coals with various sulfur contents, purchasing emission allowances on the open market and/or using sulfur-dioxide emission reduction technology.

Ash. Ash is the inorganic residue remaining after the combustion of coal. As with sulfur, ash content varies from seam to seam. Ash content is an important characteristic of coal because it impacts boiler performance and electric generating plants must handle and dispose of ash following combustion. The composition of the ash, including the proportion of sodium oxide and fusion temperature, is also an important characteristic of coal , as it helps to determine the suitability of the coal to end users. The absence of ash is also important to the process by which metallurgical coal is transformed into coke for use in steel production.

Moisture. Moisture content of coal varies by the type of coal, the region where it is mined and the location of the coal within a seam. In general, high moisture content decreases the heat value and increases the weight of the coal, thereby making it more expensive to transport. Moisture content in coal, on an as-sold basis, can range from approximately 2% to over 30% of the coal's weight.

Other. Users of metallurgical coal measure certain other characteristics, including fluidity, swelling capacity and volatility to assess the strength of coke produced from a given coal or the amount of coke that certain types of coal will yield. These characteristics may be important elements in determining the value of the metallurgical coal we produce and market.

The Coal Industry

Background. Coal is traded globally and can be transported to demand centers by ship, rail, barge or truck. World coal production reached a record 7.6 billion tonnes in 2011 according to The International Energy Agency (IEA) and the World Coal Association. Total hard coal production increased 8% to an estimated 6.7 billion tonnes in 2011 from 2010 levels, while global production of brown coal was relatively flat at 1 billion tonnes. Also according to IEA estimates, China remained the largest producer of coal in the world, producing over 3.4 billion tonnes in 2011. The United States and India follow China with hard coal production of over 1 billion tonnes and 580 million tonnes, respectively, in 2011.

Cross-border coal trade of hard coal was close to 1.2 billion tonnes in 2012 according to preliminary information. China remained the largest importer of globally traded coal in 2012, taking over 220 million tonnes of hard coal, having surpassed Japan in 2011. Japan imported more than 180 million tonnes in 2012, followed by South Korea with nearly 130 tonnes, both exhibiting growth. OECD Europe was on pace throughout 2012 to surpass 2011 import levels of 226 million tonnes.

Among the nations principally supplying coal to the global power and steel markets are Australia, historically the world's largest coal exporter, as well as Indonesia, Russia, the United States, Columbia and South Africa. Australia has significant reserves, however growing environmental constraints, higher labor and capital costs, and the development of reserves farther from export facilities are increasing development and production costs. Indonesia continues to exhibit substantial growth in its coal exports; however its growing domestic energy demand, together with recent regulatory requirements, may result in a decrease in exports as it moves toward greater self-sufficiency. Increasing calls to bolster domestic power supply, together with pressure to improve wages for miners, may also limit South African exports in the future.

Global Coal Supply and Demand. The supply and demand fundamentals in global coal markets were relatively challenged in 2012. Europe's ongoing sovereign debt problems continued to strain the global economy in 2012. Within Europe, this economic uncertainty lowered demand for imported finished goods, which led to reduced steel consumption and therefore lower demand for metallurgical coal. In addition, inflation control measures enacted by China, which restricted lending and investment, combined with strong hydro-electric generation and slower growth in the developed world reduced Chinese exports, which in turn had an impact on thermal and metallurgical coal demand in China.

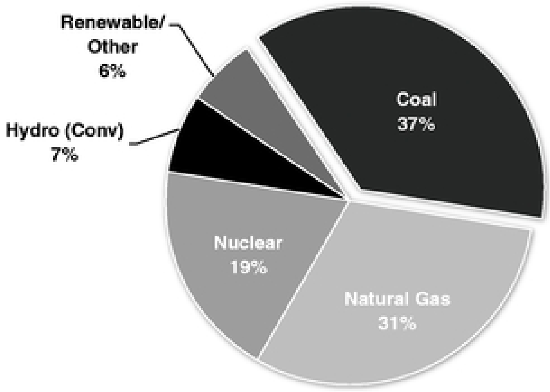
In addition to the strain on global demand, Australia's recovery from flooding in 2011, together with the increasing expansion of Indonesian coal production, created a situation in which global coal supply growth outpaced demand growth in 2012. This was seen domestically as well, primarily as a result of the unseasonably warm winter that caused coal stockpiles to build at coal-fueled power plants and low natural gas prices.

Despite the challenges in 2012, there were some positive trends. Demand for thermal coal imports in Europe grew as coal-powered generation realized substantial cost advantages to natural gas. That, combined with pressure to reduce subsidized domestic coal production in Europe, could indicate a growing demand for imported coal in Europe. Additionally, toward the end of 2012, global production began to recede while China increased imports of both metallurgical and thermal coal, and total United States exports continued to grow in 2012, up approximately 17 million tons to 124 million tons, or 15% over 2011 levels, according to preliminary data. The IEA in its medium-term coal market report for 2012 indicates coal demand is again expected to rise through 2017.

U.S. Coal Consumption. In the United States, coal is used primarily by power plants to generate electricity, by steel companies to produce coke for use in blast furnaces and by a variety of industrial users to heat and power foundries, cement plants, paper mills, chemical plants and other manufacturing or processing facilities. Although final data is not yet available, coal consumption in the United States is estimated to be approximately 894 million tons in 2012, according to the Energy Information Administration's (EIA) Short Term Energy Outlook. Coal consumption has improved month on month after last year's warm winter decreased overall electricity generation requirements and impacted generation fuels, including coal and natural gas.

According to the EIA, coal accounted for approximately 37% of U.S. electricity generation from January through November 2012. This is a decrease of approximately 5% from full-year 2011, as increased competition between fuels and an unseasonably warm winter led to lower electricity demand and therefore lower consumption of fossil fuels. The warm winter also pushed coal stockpiles higher at electric power plants. Inventories remained above the 5-year average through November 2012.

The following chart shows the breakdown of U.S. electricity generation by energy source for January through November 2012, according to the EIA:



Source: EIA Electricity Monthly Update (January 2013).

The following chart shows historical and projected demand trends for U.S. coal by consuming sector for the periods indicated, according to the EIA:

Sector	Actual 2007	Estimated 2012	Forecast 2013	Forecast 2020	Forecast 2040	Annual Growth 2011 - 2040
	(Tons, in millions)					
Electric power	1,045	829	847	890	984	0.2%
Other industrial	57	42	42	50	52	0.4%
Coke plants	23	21	21	23	18	(0.7)%
Residential/commercial	3	3	3	3	3	(0.3)%
Coal-to-liquids	—	—	—	—	14	n/a
*Total U.S. coal consumption	1,128	894	912	966	1,071	0.2%

Source: EIA Annual Energy Outlook 2013
EIA Short Term Energy Outlook (January 2013)
EIA Monthly Energy Review (January 2013)

* Columns may not total due to rounding.

Historically, coal has been considerably less expensive than natural gas or oil. However the growth of hydraulic fracturing (fracking) combined with the warm winter resulted in record high supplies and inventories of natural gas throughout most of 2012. This oversupply altered the competitive balance throughout much of the year and allowed natural gas to gain market share in the power generation market compared to historical levels.

The average wellhead price of natural gas in 2012 was $2.52 (EIA, Jan-Oct 2012) which compares to $4.48 and $3.95 in 2010 and 2011, respectively. The 2012 price represents the lowest annual price since 1999. As prices dropped, drill rigs deployed for natural gas production also declined, ending 2012 at 429 rigs according to Baker Hughes. This compares to 919 and 809 at the end of 2010 and 2011, respectively. The decline in prices along with less development could be a sign that prices at this level do not provide enough incentive to expand drilling activity. Therefore, we believe that natural gas prices are at unsustainably low levels. We believe that coal will regain market share in the domestic electric power market as natural gas prices climb to more sustainable levels.

U.S. Coal Production. The United States is the second largest coal producer in the world, exceeded only by China. According to the EIA, there is over 200 billion tons of recoverable coal in the United States. The U.S. Department of Energy estimates that current domestic recoverable coal reserves could supply enough electricity to satisfy domestic demand for over 150 years.

Coal is mined from coal fields throughout the United States, with the major production centers located in the western United States, the Appalachian region and the Interior. According to the EIA, U.S. coal production declined an estimated 75 million tons in 2012, to 1.02 billion tons, primarily due to the decline in domestic utility demand.

The EIA subdivides United States coal production into three major areas: Western, Appalachia and Interior.

The Western area includes the Powder River Basin and the Western Bituminous region. According to the EIA, coal produced in the western United States declined from an estimated 587 million tons in 2011 to 540 million tons in 2012 as reduced demand for power generation and lower natural gas prices negatively affected coal demand. The Powder River Basin is located in northeastern Wyoming and southeastern Montana and is the largest producing region in the United States. Coal from this region is sub-bituminous coal with low sulfur content ranging from 0.2% to 0.9% and heating values ranging from 8,000 to 9,500 Btu. The price of Powder River Basin coal is generally less than that of coal produced in other regions because Powder River Basin coal exists in greater abundance and is easier to mine and, thus, has a lower cost of production. The Western Bituminous region includes Colorado, Utah and southern Wyoming. Coal from this region typically has low sulfur content ranging from 0.4% to 0.8% and heating values ranging from 10,000 to 12,200 Btu.

The Appalachia region is further dividend into north, central and southern regions. According to the EIA, coal produced in the Appalachian region decreased from 337 million tons in 2011 to 304 million tons in 2012, primarily as a result of natural gas displacement but also because of the depletion of economically attractive reserves, permitting issues, and increasing costs of production. Central Appalachia includes eastern Kentucky, Tennessee, Virginia and southern West Virginia. Coal mined from this region generally has a high heat value ranging from 11,400 to 13,200 Btu and a low sulfur content ranging from 0.2% to 2.0%. Northern Appalachia includes Maryland, Ohio, Pennsylvania and northern West Virginia. Coal from this region generally has a high heat value ranging from 10,300 to 13,500 Btu and a high sulfur content ranging from 0.8% to 4.0%. Southern Appalachia primarily covers Alabama and generally has a heat content ranging from 11,300 to 12,300 Btu and a sulfur content ranging from 0.7% to 3.0%.

The Interior region includes the Illinois Basin, Gulf Lignite production in Texas and Louisiana, and a small producing area in Kansas, Oklahoma, Missouri and Arkansas. The Illinois Basin is the largest producing region in the Interior and consists of Illinois, Indiana and western Kentucky. According to the EIA, coal produced in the Interior region decreased from 180 million tons in 1994 to approximately 171 and 176 million tons in 2011 and 2012, respectively. Coal from the Illinois Basin generally has a heat value ranging from 10,100 to 12,600 Btu and has a high sulfur content ranging from 1.0% to 4.3%. Despite its high sulfur content, coal from the Illinois Basin can generally be used by electric power generation facilities that have installed pollution control devices, such as scrubbers, to reduce emissions.

U.S. Coal Exports and Imports. Coal exports grew almost 17 million tons to 124 million in 2012, a record for the United States. Supporting this was demand growth in Europe on fuel-on-fuel competition. We expect this trend to continue as demand for United States coal grows in the seaborne market. Interest in access to the coal markets overseas by domestic producers, along with increased international consumer interest in the United States coal, has fueled considerable growth in developing new port capacity in the United States.

Historically, coal imported from abroad has represented a relatively small share of total domestic coal consumption, and this remained the case in 2012. Imports reached close to 36 million tons in 2007, but have fallen since then. According to the EIA, coal imports declined from 13.1 million tons in 2011 to 9.6 million in 2012. The decline is mostly attributable to more competitive pricing for domestic coal and stronger demand from international markets for seaborne coal. The majority of the coal imported into the United States originates from Columbia. We expect imports into the United States to continue to decrease in the near-term as more and more global coal will likely be directed to Asia.

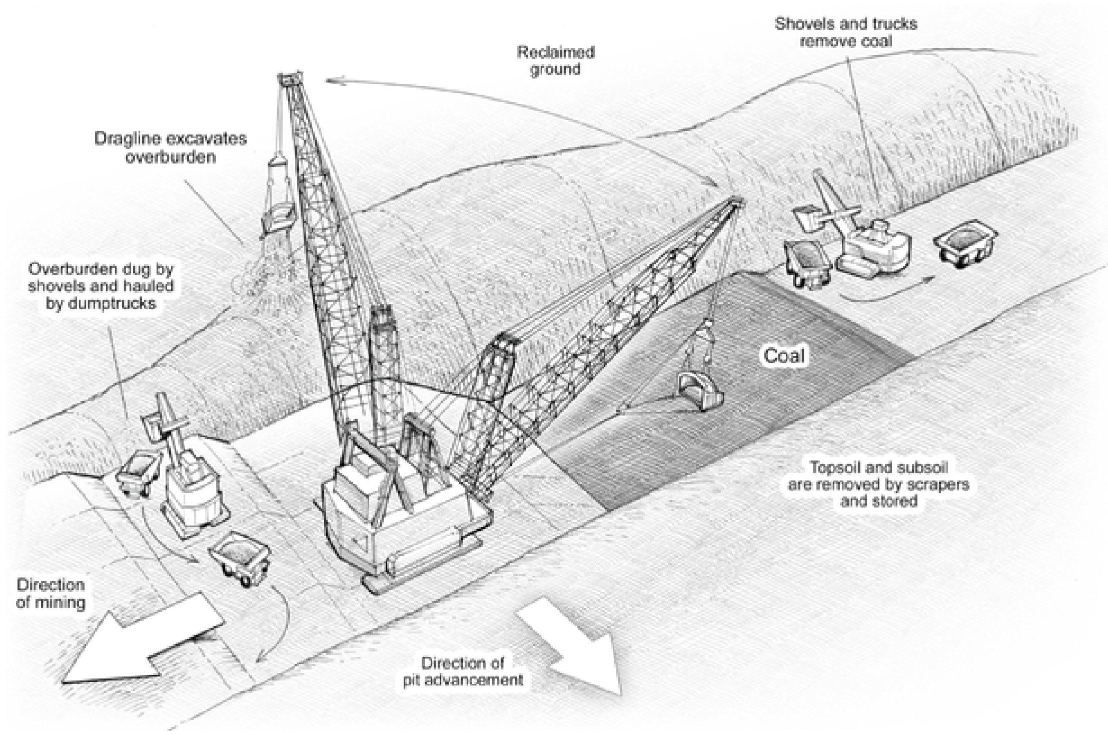
Coal Mining Methods

The geological characteristics of our coal reserves largely determine the coal mining method we employ. We use two primary methods of mining coal: surface mining and underground mining.

Surface Mining. We use surface mining when coal is found close to the surface. We have included the identity and location of our surface mining operations below under "Our Mining Operations—General." The majority of the coal we produce comes from surface mining operations.

Surface mining involves removing the topsoil then drilling and blasting the overburden (earth and rock covering the coal) with explosives. We then remove the overburden with heavy earth-moving equipment, such as draglines, power shovels, excavators and loaders. Once exposed, we drill, fracture and systematically remove the coal using haul trucks or conveyors to transport the coal to a preparation plant or to a loadout facility. We reclaim disturbed areas as part of our normal mining activities. After final coal removal, we use draglines, power shovels, excavators or loaders to backfill the remaining pits with the overburden removed at the beginning of the process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life into the natural habitat and make other improvements that have local community and environmental benefits.

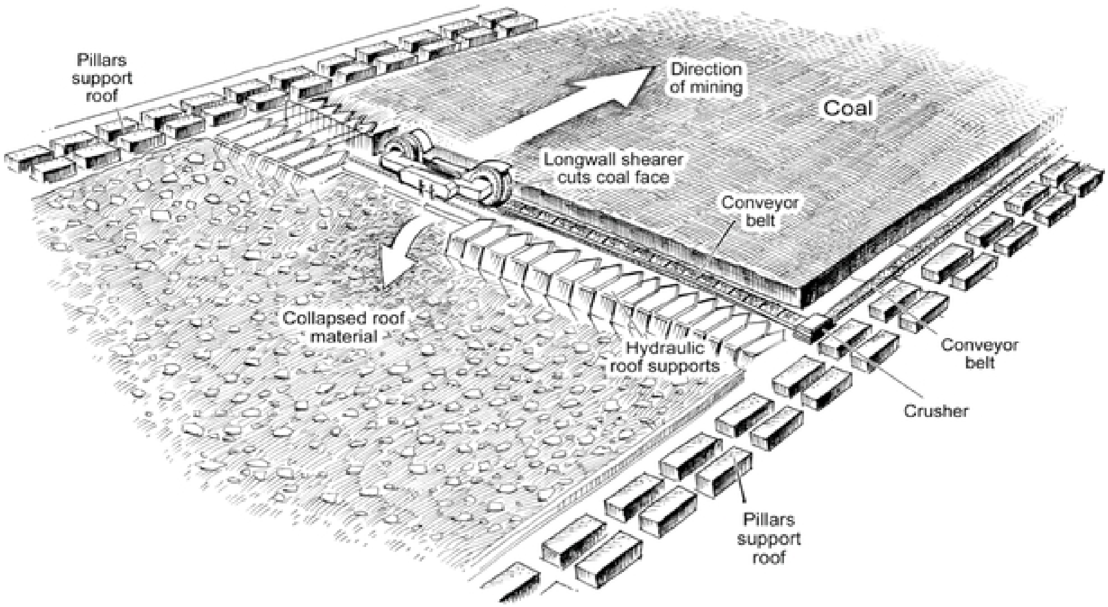
The following diagram illustrates a typical dragline surface mining operation:



Underground Mining. We use underground mining methods when coal is located deep beneath the surface. We have included the identity and location of our underground mining operations below under "Our Mining Operations—General."

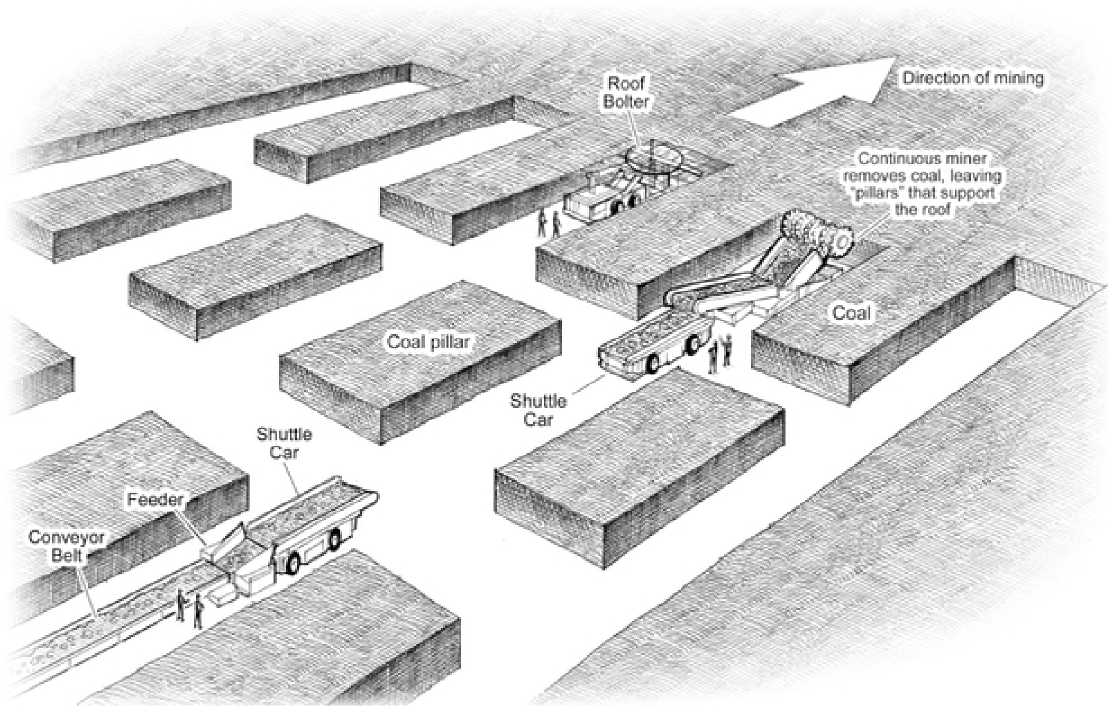
Our underground mines are typically operated using one or both of two different mining techniques: longwall mining and room-and-pillar mining.

Longwall Mining. Longwall mining involves using a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. Ultimate seam recovery using longwall mining techniques can exceed 75%. In longwall mining, continuous miners are used to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion. The following diagram illustrates a typical underground mining operation using longwall mining techniques:



Room-and-Pillar Mining. Room-and-pillar mining is effective for small blocks of thin coal seams. In room-and-pillar mining, a network of rooms is cut into the coal seam, leaving a series of pillars of coal to support the roof of the mine. Continuous miners are used to cut the coal and shuttle cars are used to transport the coal to a conveyor belt for further transportation to the surface. The pillars generated as part of this mining method can constitute up to 40% of the total coal in a seam. Higher seam recovery rates can be achieved if retreat mining is used. In retreat mining, coal is mined from the pillars as workers retreat. As retreat mining occurs, the roof is allowed to collapse in a controlled fashion.

The following diagram illustrates our typical underground mining operation using room-and-pillar mining techniques:



Coal Preparation and Blending. We crush the coal mined from our Powder River Basin mining complexes and ship it directly from our mines to the customer. Typically, no additional preparation is required for a saleable product. Coal extracted from some of our underground mining operations contains impurities, such as rock, shale and clay occupying in a wide range of particle sizes. The majority of our mining operations in the Appalachia region and a few of our mines in the Western Bituminous region use a coal preparation plant located near the mine or connected to the mine by a conveyor. These coal preparation plants allow us to treat the coal we extract from those mines to ensure a consistent quality and to enhance its suitability for particular end-users. In addition, depending on coal quality and customer requirements, we may blend coal mined from different locations, including coal produced by third parties, in order to achieve a more suitable product.

The treatments we employ at our preparation plants depend on the size of the raw coal. For coarse material, the separation process relies on the difference in the density between coal and waste rock where, for the very fine fractions, the separation process relies on the difference in surface chemical properties between coal and the waste minerals. To remove impurities, we crush raw coal and classify it into various sizes. For the largest size fractions, we use dense media vessel separation techniques in which we float coal in a tank containing a liquid of a pre-determined specific gravity. Since coal is lighter than its impurities, it floats, and we can separate it from rock and shale. We treat intermediate sized particles with dense medium cyclones, in which a liquid is spun at high speeds to separate coal from rock. Fine coal is treated in spirals, in which the differences in density between coal and rock allow them, when suspended in water, to be separated. Ultra fine coal is recovered in column flotation cells utilizing the differences in surface chemistry between coal and rock. By injecting stable air bubbles through a suspension of ultra fine coal and rock, the coal particles adhere to the bubbles and rise to the surface of the column where they are removed. To minimize the moisture content in coal, we process most coal sizes through centrifuges. A centrifuge spins coal very quickly, causing water accompanying the coal to separate.

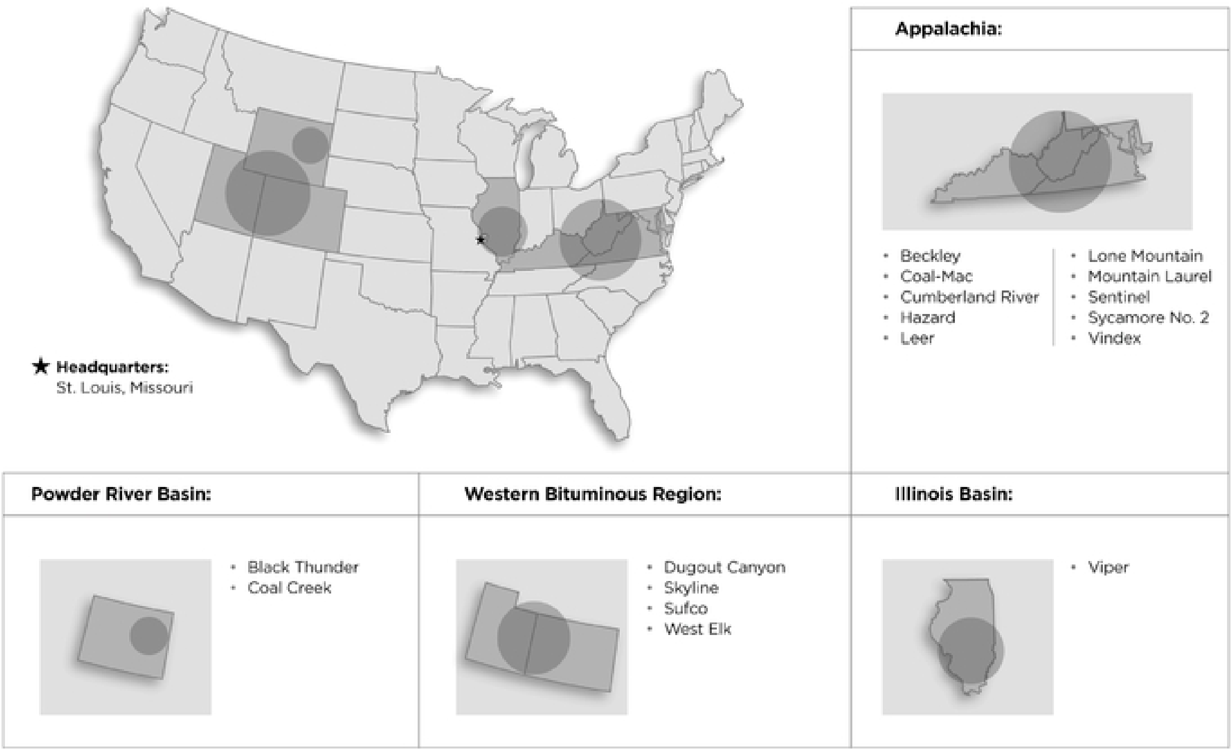
For more information about the locations of our preparation plants, you should see the section entitled "Our Mining Operations" below.

Our Mining Operations

General. At December 31, 2012, we operated, or contracted out the operation of, 32 mines in the United States. Our reportable segments are based on the major coal producing basins in which the Company operates. The Company's operating segments are the Powder River Basis (PRB) segment, with operations in Wyoming; the Western Bituminous (WBIT) segment, with operations in Utah and Colorado; the Appalachia (APP) segment, with operations in West Virginia, Kentucky, Maryland and Virginia; and our Illinois segment, which includes our operations in Illinois. Geology, coal transportation routes to consumers, regulatory environments and coal quality can vary from segment to segment. These regional distinctions have caused market and contract pricing environments to develop by coal region and form the basis for the segmentation of our operations. We incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2012, 2011 and 2010 contained in Note 24 beginning on page F-46.

In general, we have developed our mining complexes and preparation plants at strategic locations in close proximity to rail or barge shipping facilities. Coal is transported from our mining complexes to customers by means of railroads, trucks, barge lines, and ocean-going vessels from terminal facilities. We currently own or lease under long-term arrangements a substantial portion of the equipment utilized in our mining operations. We employ sophisticated preventative maintenance and rebuild programs and upgrade our equipment to ensure that it is productive, well-maintained and cost-competitive.

The following map shows the locations of our active mining operations:



The following table provides a summary of information regarding our active mining complexes as of December 31, 2012, including the total sales associated with these complexes for the years ended December 31, 2010, 2011 and 2012 and the total reserves associated with these complexes at December 31, 2012. The amount disclosed below for the total cost of property, plant and equipment of each mining complex does not include the costs of the coal reserves that we have assigned to an individual complex. The table does not include those mining complexes that we have closed or idled during the 2012 calendar year. As indicated by the footnotes included in the table below, certain of the mining complexes listed below were acquired by us on June 15, 2011 as a result of our acquisition of International Coal Group, Inc.

Mining Complex	Captive Mines[1]	Contract Mines[1]	Mining Equipment	Railroad	Tons Sold[2][3] 2010 (Million tons)	2011	2012	Total Cost of Property, Plant and Equipment at December 31, 2012 ($ in millions)	Assigned Reserves (Million tons)
Powder River Basin:									
Black Thunder	S	—	D, S	UP/BN	116.2	104.9	92.9	$ 1,164.0	1,466.1
Coal Creek	S	—	D, S	UP/BN	11.4	10.0	7.5	158.8	170.3
Western Bituminous:									
Dugout Canyon	U	—	LW, CM	UP	2.3	2.2	1.7	99.7	13.3
Skyline	U	—	LW, CM	UP	2.9	2.9	1.6	219.6	18.1
Sufco	U	—	LW, CM	UP	6.1	6.1	5.6	261.3	42.2
West Elk	U	—	LW, CM	UP	4.8	5.8	6.7	464.8	80.4
Appalachia:									
Coal-Mac	S	U	L, E	NS/CSX	3.2	3.3	3.3	205.3	26.3
Cumberland River	U(2)	U(3)	L, CM, HW	NS	1.5	2.2	1.5	186.5	25.0
Lone Mountain	U(4)	—	CM	NS/CSX	2.1	2.4	2.0	262.3	25.4
Mountain Laurel	U	S(2)	L, LW, CM	CSX	5.1	4.1	3.7	510.0	63.6
Hazard*	S(4)	—	L, S	CSX	N/A	1.6	2.1	113.8	44.4
Beckley*	U	—	CM	CSX	N/A	0.6	1.1	103.3	28.5
Vindex*	S(3)	—	L, S	CSX	N/A	0.6	1.0	86.1	18.5
Sycamore No. 2*	—	U	CM	CSX	N/A	0.2	0.4	7.9	7.7
Sentinel*	U	—	CM	CSX	N/A	0.6	1.2	55.6	15.0
Leer*	U	—	CM, LW	CSX	—	—	—	280.1	34.5
Illinois:									
Viper*	U	—	CM	—	N/A	1.1	2.1	81.2	18.5
Totals					155.6	148.6	134.4	$ 4,260.3	2,097.8(4)

S = Surface mine
U = Underground mine

D = Dragline
L = Loader/truck
S = Shovel/truck
E = Excavator/truck
LW = Longwall
CM = Continuous miner
HW = Highwall miner

UP = Union Pacific Railroad
CSX = CSX Transportation
BN = Burlington Northern-Santa Fe Railway
NS = Norfolk Southern Railroad

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* Mining complex acquired on June 15, 2011 in connection with our acquisition of International Coal Group, Inc. The above table only shows tons sold from these mining complexes after June 14, 2011, and does not include tons sold by the prior owner in 2010 or 2011.

(1) Amounts in parentheses indicate the number of captive and contract mines, if more than one, at the mining complex as of December 31, 2012. Captive mines are mines that we own and operate on land owned or leased by us. Contract mines are mines that other operators mine for us under contracts on land owned or leased by us.

(2) Tons of coal we purchased from third parties that were not processed through our loadout facilities are not included in the amounts shown in the table above.

(3) Does not include tons of coal sold from the following mining complexes that were closed or idled during the 2012 calendar year: Arch of Wyoming, East Kentucky, Eastern, Flint Ridge, Imperial, Knott County/Raven and Patriot. We sold 2.2 million tons of coal from these mining complexes in 2012.

(4) The total for assigned reserves does not include 154.7 million tons of reserves that are assigned to non-active mining complexes.

Powder River Basin

Black Thunder. Black Thunder is a surface mining complex located on approximately 35,700 acres in Campbell County, Wyoming. The Black Thunder complex extracts steam coal from the Upper Wyodak and Main Wyodak seams.

We control a significant portion of the coal reserves through federal and state leases. The Black Thunder mining complex had approximately 1.5 billion tons of proven and probable reserves at December 31, 2012. The air quality permit for the Black Thunder mine allows for the mining of coal at a rate of 190 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021 before annual output starts to significantly decline, although in practice production would drop in phases extending the ultimate mine life. Several large tracts of coal adjacent to the Black Thunder mining complex have been nominated for lease, and other potential large areas of unleased coal remain available for nomination by us or other mining operations. The U.S. Department of Interior Bureau of Land Management, which we refer to as the BLM, will determine if the tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Black Thunder mining complex currently consists of seven active pit areas and three loadout facilities. We ship all of the coal raw to our customers via the Burlington Northern-Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. Each of the loadout facilities can load a 15,000-ton train in less than two hours.

Coal Creek. Coal Creek is a surface mining complex located on approximately 7,400 acres in Campbell County, Wyoming. The Coal Creek mining complex extracts steam coal from the Wyodak-R1 and Wyodak-R3 seams.

We control a significant portion of the coal reserves through federal and state leases. The Coal Creek mining complex had approximately 170.3 million tons of proven and probable reserves at December 31, 2012. The air quality permit for the Coal Creek mine allows for the mining of coal at a rate of 50 million tons per year. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2025 before annual output starts to significantly decline. One tract of coal adjacent to the Coal Creek mining complex has been nominated for lease, and other potential areas of unleased coal remain available for nomination by us or other mining operations. The BLM will determine if these tracts will be leased and, if so, the final boundaries of, and the coal tonnage for, these tracts.

The Coal Creek complex currently consists of two active pit areas and a loadout facility. We ship all of the coal raw to our customers via the Burlington Northern-Santa Fe and Union Pacific railroads. We do not process the coal mined at this complex. The loadout facility can load a 15,000-ton train in less than three hours.

Western Bituminous

Dugout Canyon. Dugout Canyon mine is an underground mining complex located on approximately 18,600 acres in Carbon County, Utah. The Dugout Canyon mining complex has extracted steam coal from the Rock Canyon and Gilson seams.

We control a significant portion of the coal reserves through federal and state leases. The Dugout Canyon mining complex had approximately 13.3 million tons of proven and probable reserves at December 31, 2012. The coal seam currently being mined could sustain current production levels until approximately 2020, at which point we will need to transition to another area to continue mining.

The complex currently consists of one active continuous miner section and a truck loadout facility. We ship all of the coal to our customers via the Union Pacific railroad or by highway trucks. We wash a portion of the coal we produce at a 400-ton-per-hour preparation plant. The loadout facility can load approximately 20,000 tons of coal per day into highway trucks. Coal shipped by rail is loaded through a third-party facility capable of loading an 11,000-ton train in less than three hours.

Skyline. Skyline is an underground mining complex located on approximately 14,300 acres in Carbon and Emery Counties, Utah. The Skyline mining complex extracts steam coal from the Lower O'Conner A seam.

We control a significant portion of the coal reserves through federal leases and smaller portions through county and private leases. The Skyline mining complex had approximately 18.1 million tons of proven and probable reserves at December 31, 2012. The coal seam currently being mined could sustain current production levels until approximately 2019, at which point we will need to transition to another area to continue mining.

The Skyline complex currently consists of a longwall, two continuous miner sections and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad or by highway trucks. We process a portion of the coal mined at this complex at a nearby preparation plant. The loadout facility can load a 12,000-ton train in less than four hours.

Sufco. Sufco is an underground mining complex located on approximately 23,800 acres in Sevier County, Utah. The Sufco mining complex extracts steam coal from the Upper Hiawatha seam.

We control a significant portion of the coal reserves through federal and state leases. The Sufco mining complex had approximately 42.2 million tons of proven and probable reserves at December 31, 2012. The coal seam currently being mined could sustain current production levels through 2020, at which point a new coal seam will have to be accessed in order to continue mining.

The Sufco complex currently consists of a longwall, three continuous miner sections and a loadout facility located approximately 80 miles from the mine. We ship all of the coal raw to our customers via the Union Pacific railroad or by highway trucks. Processing at the mine site consists of crushing and sizing. The rail loadout facility is capable of loading an 11,000-ton train in less than three hours.

West Elk. West Elk is an underground mining complex located on approximately 17,800 acres in Gunnison County, Colorado. The West Elk mining complex extracts steam coal from the E seam.

We control a significant portion of the coal reserves through federal and state leases. The West Elk mining complex had approximately 80.4 million tons of proven and probable reserves at December 31, 2012. Without the addition of more coal reserves, the current reserves could sustain current production levels through 2025 before annual output starts to significantly decline.

The West Elk complex currently consists of a longwall, one continuous miner section and a loadout facility. We ship most of the coal raw to our customers via the Union Pacific railroad. In 2010, we finished constructing a new coal preparation plant with supporting coal handling facilities at the West Elk mine site. The loadout facility can load an 11,000-ton train in less than three hours.

Appalachia

Coal-Mac. Coal-Mac is a surface and underground mining complex located on approximately 46,800 acres in Logan and Mingo Counties, West Virginia. Surface mining operations at the Coal-Mac mining complex extract steam coal primarily from the Coalburg and Stockton seams. Underground mining operations at the Coal-Mac mining complex extract steam coal from the Coalburg seam.

We control a significant portion of the coal reserves through private leases. The Coal-Mac mining complex had approximately 26.3 million tons of proven and probable reserves at December 31, 2012. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2018 before annual output starts to significantly decline.

The complex currently consists of one captive surface mine, one contract underground mine, a preparation plant and two loadout facilities, which we refer to as Holden 22 and Ragland. We ship coal trucked to the Ragland loadout facility directly to our customers via the Norfolk Southern railroad. The Ragland loadout facility can load a 10,000-ton train in less than four hours. We ship coal trucked to the Holden 22 loadout facility directly to our customers via the CSX railroad. We wash all of the coal transported to the Holden 22 loadout facility at an adjacent 600-ton-per-hour preparation plant. The Holden 22 loadout facility can load a 10,000-ton train in about four hours.

Cumberland River. Cumberland River is an underground mining complex located on approximately 33,400 acres in Wise County, Virginia and Letcher County, Kentucky. Underground mining operations at the Cumberland River mining complex extract steam and metallurgical coal from the Imboden, Taggart Marker, Middle Taggart, Upper Taggart, Owl, and Parsons seams.

We control a significant portion of the coal reserves through private leases. The Cumberland River mining complex had approximately 25.0 million tons of proven and probable reserves at December 31, 2012. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2022 before annual output starts to significantly decline.

As of December 31, 2012, the complex consisted of five underground mines (two captive, three contract) operating seven continuous miner sections, a preparation plant and a loadout facility. Since December 31, 2012 one contract mine has been shut down. We process the coal through a 750-ton-per-hour preparation plant before shipping it to our customers via the Norfolk Southern railroad. The loadout facility can load a 12,000-ton train in about four hours.

Lone Mountain. Lone Mountain is an underground mining complex located on approximately 54,000 acres in Harlan County, Kentucky and Lee County, Virginia. The Lone Mountain mining complex extracts steam and metallurgical coal from the Kellioka, Darby and Owl seams.

We control a significant portion of the coal reserves through private leases. The Lone Mountain mining complex had approximately 25.4 million tons of proven and probable reserves at December 31, 2012. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2023 before annual output starts to significantly decline.

The complex currently consists of four underground mines operating a total of nine continuous miner sections. We process coal through a 1,200-ton-per-hour preparation plant. We then ship the coal to our customers via the Norfolk Southern or CSX railroad. The loadout facility can load a 12,500-ton unit train in less than four hours.

Mountain Laurel. Mountain Laurel is an underground and surface mining complex located on approximately 38,400 acres in Logan County and Boone County, West Virginia. Underground mining operations at the Mountain Laurel mining complex extract steam and metallurgical coal from the Cedar Grove and Alma seams. Surface mining operations at the Mountain Laurel mining complex extract coal from a number of different splits of the Five Block, Stockton and Coalburg seams.

We control a significant portion of the coal reserves through private leases. The Mountain Laurel mining complex had approximately 63.6 million tons of proven and probable reserves at December 31, 2012. The longwall mine is expected to operate through at least 2018 and potentially longer. In addition, the existing reserve base should support continuous miner operations for many years beyond that date.

The complex currently consists of one underground mine operating a longwall and a total of four continuous miner sections, two contract surface operations, a preparation plant and a loadout facility. We process most of the coal through a 2,100-ton-per-hour preparation plant before shipping the coal to our customers via the CSX railroad. The loadout facility can load a 15,000-ton train in less than four hours.

Hazard. Hazard is a mining complex that consists of four surface mines, a preparation plant, a unit train loadout and other support facilities located on approximately 122,000 acres in eastern Kentucky. The coal from Hazard's mines is being extracted from the Hazard 10, Hazard 9, Hazard 8, Hazard 7 and Hazard 5A seams. Nearly all of the surface-mined coal is marketed as a blend of shipped direct product with the remainder being processed at the Flint Ridge preparation plant. Coal is transported by on-highway trucks from the mines to the rail loadout, which is served by CSX. Some coal is direct shipped to the customer by truck.

A majority of the coal reserves are owned; the remainder are held through private leases. The mining complex had approximately 44.4 million tons of proven and probable reserves at December 31, 2012, which could sustain current production levels until at least 2030. The loadout facility can load a 12,500-ton train in less than 4 hours.

Beckley. The Beckley mining complex is located on approximately 23,400 acres in Raleigh County, West Virginia. Beckley is extracting high quality, low-volatile metallurgical coal in the Pocahontas No. 3 seam.

A significant portion of the coal reserves are controlled through private leases. As of December 31, 2012, we had approximately 28.5 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2030. Coal is belted from the mine to a 600-ton-per-hour preparation plant before shipping the coal via the CSX railroad. The loadout facility can load a 10,000-ton train in less than four hours.

Vindex. The Vindex mining complex consists of three surface mines located on approximately 43,200 acres in Garrett and Allegany Counties, Maryland. Mining operations at these surface mines extract coal from the Upper Freeport, Middle Kittanning, Pittsburgh, Little Pittsburgh and Redstone seams.

We control all of the coal reserves through private leases. As of December 31, 2012, we had approximately 18.5 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until at least 2025.

Sycamore No. 2. The Sycamore No. 2 mining complex is an active underground mine operated by a contract miner located on approximately 8,900 acres in Harrison County, West Virginia. Mining operations extract coal from the Pittsburgh seam. The coal produced by this mining complex is sold on a raw basis and is transported to current customers by truck.

As of December 31, 2012, the Sycamore No. 2 mining complex had approximately 7.7 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2028.

Sentinel. The Sentinel mining complex consists of one underground mine, a preparation plant and a loadout facility located on approximately 25,200 acres in Barbour County, West Virginia. Mining operations currently extract coal from the Clarion coal seam. Coal from the Sentinel mining complex is processed through the preparation plant and shipped by CSX rail to customers.

We control a significant portion of the Clarion seam coal reserves through private leases. As of December 31, 2012, we had approximately 15.0 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2021.

Leer (formally Tygart Valley). The Leer Complex, located in Taylor County, West Virginia, includes approximately 34.5 million tons of deep coal reserves as of December 31, 2012 and has both steam and metallurgical quality coal in the Lower Kittanning seam, covering approximately 68,000 acres. Substantially all of the reserves at Leer are owned rather than leased from third parties.

Construction of the Leer Complex began in June 2010 and initial coal production commenced in November 2011. At full output, the Leer Complex is designed to have 3.5 million tons of capacity per year of high quality coal that is well suited to both the utility market and the high volatile metallurgical market. All the production is processed through a 1,400 ton-per-hour preparation plant and loaded on the CSX railroad. A 15,000-ton train can be loaded in less than 4 hours.

Illinois

Viper. The Viper mining complex consists of one underground coal mine and a preparation plant located on approximately 48,800 acres in central Illinois near the city of Springfield. Mining operations extract steam coal from the Illinois No. 5 seam, also referred to as the Springfield seam All coal is processed through an 800 ton-per-hour preparation plant and shipped to customers by on-highway trucks.

We control a signification portion of the coal reserves through private leases. As of December 31, 2012, we had approximately 18.5 million tons of proven and probable reserves. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2026.

Sales, Marketing and Trading

Overview. Coal prices are influenced by a number of factors and can vary materially by region. The price of coal within a region is influenced by market conditions, coal quality, transportation costs involved in moving coal from the mine to the point of use and mine operating costs. For example, higher carbon and lower ash content generally result in higher prices, and higher sulfur and higher ash content generally result in lower prices within a given geographic region.

The cost of coal at the mine is also influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. It is generally less expensive to mine coal seams that are thick and located close to the surface than to mine thin underground seams. Within a particular geographic region, underground mining, which is the primary mining method we use in the Western Bituminous region and for certain of our Appalachian mines, is generally more expensive than surface mining, which is the mining method we use in the Powder River Basin, and for certain of our Appalachian mines and a Western Bituminous mine. This is the case because of the higher capital costs, including costs for construction of extensive ventilation systems, and higher per unit labor costs due to lower productivity associated with underground mining.

Our sales, marketing and trading functions are principally based in St. Louis, Missouri and consist of sales and trading, transportation and distribution, quality control and contract administration personnel as well as revenue management. We also have smaller groups of sales personnel in our Singapore and London offices. In addition to selling coal produced in our mining complexes, from time to time we purchase and sell coal mined by others, some of which we blend with coal produced from our mines. We focus on meeting the needs and specifications of our customers rather than just selling our coal production.

Customers. The Company markets its steam and metallurgical coal to domestic and foreign utilities, steel producers and other industrial facilities. For the year ended December 31, 2012, we derived approximately 16% of our total coal revenues from sales to our three largest customers—U.S. Steel, Tennessee Valley Authority, and Donau Brennstoffkontor GmbH—and approximately 36% of our total coal revenues from sales to our 10 largest customers.

In 2012, we sold coal to domestic customers located in 38 different states. The locations of our mines enable us to ship coal to most of the major coal-fueled power plants in the United States.

In addition, in 2012 we also exported coal to Europe, Asia, North America (outside the United States) and South America. Exports to foreign countries were $1.2 billion, $920.0 million and $471.5 million for the years ended December 31, 2012, 2011, and 2010, respectively. As of December 31, 2012 and 2011, trade receivables related to metallurgical-quality coal sales totaled $86.6 million and $117.4 million, respectively, or 35% and 31%, of total trade receivables, respectively. We do not have foreign currency exposure for our international sales as all sales are denominated and settled in U.S. dollars.

The Company's foreign revenues by coal destination for the year ended December 31, 2012, were as follows:

	December 31, 2012 (In thousands)
Europe (including Morocco and Turkey)	$ 674,754
Asia	203,193
North America	72,542
South America	57,184
Brokered sales	145,438
Total	1,153,111

Long-Term Coal Supply Arrangements

As is customary in the coal industry, we enter into fixed price, fixed volume long-term supply contracts, the terms of which are more than one year, with many of our customers. Multiple year contracts usually have specific and possibly different volume and pricing arrangements for each year of the contract. Long-term contracts allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. In 2012 we sold approximately 70% of our coal under long-term supply arrangements. The majority of our supply contracts include a fixed price for the term of the agreement or a pre-determined escalation in price for each year. Some of our long-term supply agreements may include a variable pricing system. While most of our sales contracts are for terms of one to five years, some are as short as one month and other contracts have terms up to nine years. At December 31, 2012, the average volume-weighted remaining term of our long-term contracts was approximately 2.77 years, with remaining terms ranging from one to eight years. At December 31, 2012, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 221 million tons.

We typically sell coal to customers under long-term arrangements through a "request-for-proposal" process. The terms of our coal sales agreements result from competitive bidding and negotiations with customers. Consequently, the terms of these contracts vary by customer, including base price adjustment features, price re-opener terms, coal quality requirements, quantity parameters, permitted sources of supply, future regulatory changes, extension options, *force majeure*, termination, damages and assignment provisions. Our long-term supply contracts typically contain provisions to adjust the base price due to new statutes, ordinances or regulations. Additionally, some of our contracts contain provisions that allow for the recovery of costs affected by modifications or changes in the interpretations or application of any applicable statute by local, state or federal government authorities. These provisions only apply to the base price of coal contained in these supply contracts. In some circumstances, a significant adjustment in base price can lead to termination of the contract.

Certain of our contracts contain index provisions that change the price based on changes in market based indices and or changes in economic indices. Certain of our contracts contain price re-opener provisions that may allow a party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on prevailing market price or, in some instances, require us to negotiate a new price, sometimes within a specified range of prices. In a limited number of agreements, if the parties do not agree on a new price, either party has an option to terminate the contract. In addition, certain of our contracts contain clauses that may allow customers to terminate the contract in the event of certain changes in environmental laws and regulations that impact their operations.

Coal quality and volumes are stipulated in coal sales agreements. In most cases, the annual pricing and volume obligations are fixed, although in some cases the volume specified may vary depending on the customer consumption requirements. Most of our coal sales agreements contain provisions requiring us to deliver coal within certain ranges for specific coal characteristics such as heat content (for thermal coal contracts), volatile matter (for metallurgical coal contracts), and for both types of contracts, sulfur, ash and moisture content. Failure to meet these specifications can result in economic penalties, suspension or cancellation of shipments or termination of the contracts.

Our coal sales agreements also typically contain *force majeure* provisions allowing temporary suspension of performance by us or our customers, during the duration of events beyond the control of the affected party, including events such as strikes, adverse mining conditions, mine closures or serious transportation problems that affect us or unanticipated plant outages that may affect the buyer. Our contracts also generally provide that in the event a *force majeure* circumstance exceeds a certain time period, the unaffected party may have the option to terminate the purchase or sale in whole or in part. Some contracts stipulate that this tonnage can be made up by mutual agreement or at the discretion of the buyer. Agreements between our customers and the railroads servicing our mines may also contain *force majeure* provisions. Generally, our coal sales agreements allow our customer to suspend performance in the event that the railroad fails to provide its services due to circumstances that would constitute a *force majeure*.

In most of our contracts, we have a right of substitution (unilateral or subject to counterparty approval), allowing us to provide coal from different mines, including third-party mines, as long as the replacement coal meets quality specifications and will be sold at the same equivalent delivered cost.

In some of our coal supply contracts, we agree to indemnify or reimburse our customers for damage to their or their rail carrier's equipment while on our property, which result from our or our agents' negligence, and for damage to our customer's equipment due to non-coal materials being included with our coal while on our property.

Trading. In addition to marketing and selling coal to customers through traditional coal supply arrangements, we seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of other marketing, trading and asset optimization strategies. From time to time, we may employ strategies to use coal and coal-related commodities and contracts for those commodities in order to manage and hedge volumes and/or prices associated with our coal sales or purchase commitments, reduce our exposure to the volatility of market prices or augment the value of our portfolio of traditional assets. These strategies may include physical coal contracts, as well as a variety of forward, futures or options contracts, swap agreements or other financial instruments.

We maintain a system of complementary processes and controls designed to monitor and manage our exposure to market and other risks that may arise as a consequence of these strategies. These processes and controls seek to preserve our ability to profit from certain marketing, trading and asset optimization strategies while mitigating our exposure to potential losses. You should see the section entitled "Quantitative and Qualitative Disclosures About Market Risk" for more information about the market risks associated with these strategies at December 31, 2012.

Transportation. We ship our coal to domestic customers by means of railcars, barges, vessels or trucks, or a combination of these means of transportation. We generally sell coal used for domestic consumption free on board (f.o.b.) at the mine or nearest loading facility. Our domestic customers normally bear the costs of transporting coal by rail, barge or vessel.

Historically, most domestic electricity generators have arranged long-term shipping contracts with rail or barge companies to assure stable delivery costs. Transportation can be a large component of a purchaser's total cost. Although the purchaser pays the freight, transportation costs still are important to coal mining companies because the purchaser may choose a supplier largely based on cost of transportation. Transportation costs borne by the customer vary greatly based on each customer's proximity to the mine and our proximity to the loadout facilities. Trucks and overland conveyors haul coal over shorter distances, while barges, Great Lake carriers and ocean vessels move coal to export markets and domestic markets requiring shipment over the Great Lakes and several river systems.

Most coal mines are served by a single rail company, but much of the Powder River Basin is served by two rail carriers: the Burlington Northern-Santa Fe railroad and the Union Pacific railroad. In the Western Bituminous region our customers are largely served by the Union Pacific railroad or by truck delivery. We generally transport coal produced at our Appalachian mining complexes via the CSX railroad or the Norfolk Southern railroad. Besides rail deliveries, some customers in the eastern United States rely on a river barge system. Our Arch Coal Terminal is located in Catlettsburg, Kentucky on a 111-acre site on the Big Sandy River above its confluence with the Ohio River. The terminal provides coal and other bulk material storage and can load and offload river barges and trucks at the facility. The terminal can provide up to 500,000 tons of storage and can load up to six million tons of coal annually for shipment on the inland waterways.

We generally sell coal to international customers at the export terminal, and we are usually responsible for the cost of transporting coal to the export terminals. In some cases we may enter into long-term throughput agreements with export terminals that contain minimum throughput obligations. In the event we do not meet those minimum thresholds, we may be obligated to pay liquidated damage amounts to such terminals. We transport our coal to Atlantic or Pacific coast terminals or terminals along the Gulf of Mexico for transportation to international customers. Our international customers are generally responsible for paying the cost of ocean freight. We may also sell coal to international customers delivered to an unloading facility at the destination country.

We own a 22% interest in Dominion Terminal Associates, a partnership that operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia. The facility has a rated throughput capacity of 20 million tons of coal per year and ground storage capacity of approximately 1.7 million tons. The facility serves international customers, as well as domestic coal users located along the Atlantic coast of the United States.

We also own a 38% interest in Millennium Bulk Terminals—Longview, LLC (MBT), the owner of a bulk commodity terminal on the Columbia River near Longview, Washington. MBT is currently working to obtain the required approvals and necessary permits to complete upgrades to enable coal shipments through the brownfield terminal.

Competition

The coal industry is intensely competitive. The most important factors on which we compete are coal quality, delivered costs to the customer and reliability of supply. Our principal domestic competitors include Alpha Natural Resources, Inc., Cloud Peak Energy, CONSOL Energy Inc., Patriot Coal Corporation, Peabody Energy Corp. and Walter Energy, Inc. Some of these coal producers are larger than we are and have greater financial resources and larger reserve bases than we do. We also compete directly with a number of smaller producers in each of the geographic regions in which we operate, as well as companies that produce coal from one or more foreign countries, such as Australia, Colombia, Indonesia, South Africa and Venezuela.

Additionally, coal competes with other fuels, such as natural gas, nuclear energy, hydropower, wind, solar and petroleum, for steam and electrical power generation. Costs and other factors relating to these alternative fuels, such as safety and environmental considerations, affect the overall demand for coal as a fuel.

Suppliers

Principal supplies used in our business include petroleum-based fuels, explosives, tires, steel and other raw materials as well as spare parts and other consumables used in the mining process. We use third-party suppliers for a significant portion of our equipment rebuilds and repairs, drilling services and construction. We use sole source suppliers for certain parts of our business such as explosives and fuel, and preferred suppliers for other parts at our business such as dragline and shovel parts and related services. We believe adequate substitute suppliers are available. For more information about our suppliers, you should see "Risk Factors—Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production."

Environmental and Other Regulatory Matters

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety and the environment, including the protection of air quality, water quality, wetlands, special status species of plants and animals, land uses, cultural and historic properties and other environmental resources identified during the permitting process. Reclamation is required during production and after mining has been completed. Materials used and generated by mining operations must also be managed according to applicable regulations and law. These laws have, and will continue to have, a significant effect on our production costs and our competitive position.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, due in part to the extensive, comprehensive and changing regulatory requirements, violations during mining operations occur from time to time. We cannot assure you that we have been or will be at all times in complete compliance with such laws and regulations. While it is not possible to accurately quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. Federal and state mining laws and regulations require us to obtain surety bonds to guarantee performance or payment of certain long-term obligations, including mine closure and reclamation costs, federal and state workers' compensation benefits, coal leases and other miscellaneous obligations. Compliance with these laws has substantially increased the cost of coal mining for domestic coal producers.

Future laws, regulations or orders, as well as future interpretations and more rigorous enforcement of existing laws, regulations or orders, may require substantial increases in equipment and operating costs and delays, interruptions or a termination of operations, the extent to which we cannot predict. Future laws, regulations or orders may also cause coal to become a less attractive fuel source, thereby reducing coal's share of the market for fuels and other energy sources used to generate electricity. As a result, future laws, regulations or orders may adversely affect our mining operations, cost structure or our customers' demand for coal.

The following is a summary of the various federal and state environmental and similar regulations that have a material impact on our business:

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. When we apply for these permits and approvals, we may be required to prepare and present to federal, state or local authorities' data pertaining to the effect or impact that any proposed production or processing of coal may have upon the environment. For example, in order to obtain a federal coal lease, an environmental impact statement must be prepared to assist the BLM in determining the potential environmental impact of lease issuance, including any collateral effects from the mining, transportation and burning of coal. The authorization, permitting and implementation requirements imposed by federal, state and local authorities may be costly and time consuming and may delay commencement or continuation of mining operations. In the states where we operate, the applicable laws and regulations also provide that a mining permit or modification can be delayed, refused or revoked if officers, directors, shareholders with specified interests or certain other affiliated entities with specified interests in the applicant or permittee have, or are affiliated with another entity that has, outstanding permit violations. Thus, past or ongoing violations of applicable laws and regulations could provide a basis to revoke existing permits and to deny the issuance of additional permits.

In order to obtain mining permits and approvals from federal and state regulatory authorities, mine operators must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition or other authorized use. Typically, we submit the necessary permit applications several months or even years before we plan to begin mining a new area. Some of our required permits are becoming increasingly more difficult and expensive to obtain, and the application review processes are taking longer to complete and becoming increasingly subject to challenge, even after a permit has been issued.

Under some circumstances, substantial fines and penalties, including revocation or suspension of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws.

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, which we refer to as SMCRA, establishes mining, environmental protection, reclamation and closure standards for all aspects of surface mining as well as many aspects of underground mining. Mining operators must obtain SMCRA permits and permit renewals from the Office of Surface Mining, which we refer to as OSM, or from the applicable state agency if the state agency has obtained regulatory primacy. A state agency may achieve primacy if the state regulatory agency develops a mining regulatory program that is no less stringent than the federal mining regulatory program under SMCRA. All states in which we conduct mining operations have achieved primacy and issue permits in lieu of OSM.

In 1999, a federal court in West Virginia ruled that the stream buffer zone rule issued under SMCRA prohibited most excess spoil fills. While the decision was later reversed on jurisdictional grounds, the extent to which the rule applied to fills was left unaddressed. On December 12, 2008, OSM finalized a rulemaking regarding the interpretation of the stream buffer zone provisions of SMCRA which confirmed that excess spoil from mining and refuse from coal preparation could be placed in permitted areas of a mine site that constitute waters of the United States. On November 30, 2009, OSM announced that it would re-examine and reinterpret the regulations finalized eleven months earlier. We cannot predict how the regulations may change or how they may affect coal production, though there are reports that drafts of OSM's preferred alternative rule would, if finalized, curtail surface mining operations in and near streams—especially in central Appalachia.

SMCRA permit provisions include a complex set of requirements which include, among other things, coal prospecting; mine plan development; topsoil or growth medium removal and replacement; selective handling of overburden materials; mine pit backfilling and grading; disposal of excess spoil; protection of the hydrologic balance; subsidence control for underground mines; surface runoff and drainage control; establishment of suitable post mining land uses; and revegetation. We begin the process of preparing a mining permit application by collecting baseline data to adequately characterize the pre-mining environmental conditions of the permit area. This work is typically conducted by third-party consultants with specialized expertise and includes surveys and/or assessments of the following: cultural and historical resources; geology; soils; vegetation; aquatic organisms; wildlife; potential for threatened, endangered or other special status species; surface and ground water hydrology; climatology; riverine and riparian habitat; and wetlands. The geologic data and information derived from the other surveys and/or assessments are used to develop the mining and reclamation plans presented in the permit application. The mining and reclamation plans address the provisions and performance standards of the state's equivalent SMCRA regulatory program, and are also used to support applications for other authorizations and/or permits required to conduct coal mining activities. Also included in the permit application is information used for documenting surface and mineral ownership, variance requests, access roads, bonding information, mining methods, mining phases, other agreements that may relate to coal, other minerals, oil and gas rights, water rights, permitted areas, and ownership and control information required to determine compliance with OSM's Applicant Violator System, including the mining and compliance history of officers, directors and principal owners of the entity.

Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a thorough technical review. Also, before a SMCRA permit is issued, a mine operator must submit a bond or otherwise secure the performance of all reclamation obligations. After the application is submitted, a public notice or advertisement of the proposed permit is required to be given, which begins a notice period that is followed by a public comment period before a permit can be issued. It is not uncommon for a SMCRA mine permit application to take over a year to prepare, depending on the size and complexity of the mine, and anywhere from six months to two years or even longer for the permit to be issued. The variability in time frame required to prepare the application and issue the permit can be attributed primarily to the various regulatory authorities' discretion in the handling of comments and objections relating to the project received from the general public and other agencies. Also, it is not uncommon for a permit to be delayed as a result of litigation related to the specific permit or another related company's permit.

In addition to the bond requirement for an active or proposed permit, the Abandoned Mine Land Fund, which was created by SMCRA, requires a fee on all coal produced. The proceeds of the fee are used to restore mines closed or abandoned prior to SMCRA's adoption in 1977. The current fee is $0.28 per ton of coal produced from surface mines and $0.12 per ton of coal produced from underground mines. In 2012, we recorded $36.7 million of expense related to these reclamation fees.

Surety Bonds. Mine operators are often required by federal and/or state laws, including SMCRA, to assure, usually through the use of surety bonds, payment of certain long-term obligations including mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other miscellaneous obligations. Although surety bonds are usually noncancelable during their term, many of these bonds are renewable on an annual basis.

The costs of these bonds have fluctuated in recent years while the market terms of surety bonds have generally become more unfavorable to mine operators. These changes in the terms of the bonds have been accompanied at times by a decrease in the number of companies willing to issue surety bonds. In order to address some of these uncertainties, we use self-bonding to secure performance of certain obligations in Wyoming. As of December 31, 2012, we have self-bonded an aggregate of approximately $388.4 million, posted an aggregate of approximately $262.9 million in surety bonds for reclamation purposes and secured $18.0 million in letters of credit for reclamation bonding obligations. In addition, we had approximately $300.7 million of surety bonds and letters of credit outstanding at December 31, 2012 to secure workers' compensation, coal lease and other obligations.

Mine Safety and Health. Stringent safety and health standards have been imposed by federal legislation since Congress adopted the Mine Safety and Health Act of 1969. The Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed comprehensive safety and health standards on all aspects of mining operations. In addition to federal regulatory programs, all of the states in which we operate also have programs aimed at improving mine safety and health. Collectively, federal and state safety and health regulation in the coal mining industry is among the most comprehensive and pervasive systems for the protection of employee health and safety affecting any segment of U.S. industry. In reaction to recent mine accidents, federal and state legislatures and regulatory authorities have increased scrutiny of mine safety matters and passed more stringent laws governing mining. For example, in 2006, Congress enacted the MINER Act. The MINER Act imposes additional obligations on coal operators including, among other things, the following:

- development of new emergency response plans that address post-accident communications, tracking of miners, breathable air, lifelines, training and communication with local emergency response personnel;
- establishment of additional requirements for mine rescue teams;
- notification of federal authorities in the event of certain events;
- increased penalties for violations of the applicable federal laws and regulations; and
- requirement that standards be implemented regarding the manner in which closed areas of underground mines are sealed.

In 2008, the U.S. House of Representatives approved additional federal legislation which would have required new regulations on a variety of mine safety issues such as underground refuges, mine ventilation and communication systems. Although the U.S. Senate failed to pass that legislation, it is possible that similar legislation may be proposed in the future. Various states, including West Virginia, have also enacted laws to address many of the same subjects. The costs of implementing these safety and health regulations at the federal and state level have been, and will continue to be, substantial. In addition to the cost of implementation, there are increased penalties for violations which may also be substantial. Expanded enforcement has resulted in a proliferation of litigation regarding citations and orders issued as a result of the regulations.

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, each coal mine operator must secure payment of federal black lung benefits to claimants who are current and former employees and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1, 1973. The trust fund is funded by an excise tax on production of up to $1.10 per ton for coal mined in underground operations and up to $0.55 per ton for coal mined in surface operations. These amounts may not exceed 4.4% of the gross sales price. This excise tax does not apply to coal shipped outside the United States. In 2012, we recorded $72.9 million of expense related to this excise tax.

We are committed to the safety of our employees. In 2012, we spent approximately $16.5 million on MINER Act compliance and other safety improvement matters. For the seventh year in a row, we ranked first among our major diversified coal peers for our safety record and garnered 24 external awards for outstanding achievement in our core values. In addition, five of our complexes completed 2012 without a single safety incident or environmental violation.

One way we work towards meeting a zero injury rate is developing and maintaining strong safety programs. Our subsidiaries launched behavior-based safety programs in 2006, which expanded our employees' involvement in our prevention process and in identifying at-risk behaviors before incidents occur. In addition, we routinely conduct regular safety drills and exercises with state safety and MSHA officials.

Clean Air Act. The federal Clean Air Act and similar state and local laws that regulate air emissions affect coal mining directly and indirectly. Direct impacts on coal mining and processing operations include Clean Air Act permitting requirements and emissions control requirements relating to particulate matter which may include controlling fugitive dust. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the emissions of fine particulate matter measuring 2.5 micrometers in diameter or smaller, sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by coal-fueled power plants and industrial boilers, which are the largest end-users of our coal. Continued tightening of the already stringent regulation of emissions is likely, such as the Mercury and Air Toxics Standard (MATS), finalized in 2011 and discussed in more detail below. In addition, regulation of additional emissions, such as greenhouse gases, has been announced by the U.S. Environmental Protection Agency, which we refer to as EPA, and those regulations will apply to new coal-fueled power plants. Other greenhouse gas regulations apply to industrial boilers (see discussion of Climate Change, below and this application could eventually reduce the demand for coal.

Clean Air Act requirements that may directly or indirectly affect our operations include the following:

- *Acid Rain.* Title IV of the Clean Air Act, promulgated in 1990, imposed a two-phase reduction of sulfur dioxide emissions by electric utilities. Phase II became effective in 2000 and applies to all coal-fueled power plants with a capacity of more than 25-megawatts. Generally, the affected power plants have sought to comply with these requirements by switching to lower sulfur fuels, installing pollution control devices, reducing electricity generating levels or purchasing or trading sulfur dioxide emissions allowances. Although we cannot accurately predict the future effect of this Clean Air Act provision on our operations, we believe that implementation of Phase II has been factored into the pricing of the coal market.

- *Particulate Matter.* The Clean Air Act requires the EPA to set national ambient air quality standards, which we refer to as NAAQS, for certain pollutants associated with the combustion of coal, including sulfur dioxide, particulate matter, nitrogen oxides and ozone. Areas that are not in compliance with these standards, referred to as non-attainment areas, must take steps to reduce emissions levels. For example, NAAQS currently exist for particulate matter measuring 10 micrometers in diameter or smaller (PM10) and for fine particulate matter measuring 2.5 micrometers in diameter or smaller (PM2.5), and the EPA revised the PM2.5 NAAQS on December 14, 2012, making it more stringent. The states are required to make recommendations on nonattainment designations for the new NAAQS in late 2013. Once the EPA finalizes those designations, individual states must identify the sources of emissions and develop emission reduction plans. These plans may be state-specific or regional in scope. Under the Clean Air Act, individual states have up to 12 years from the date of designation to secure emissions reductions from sources contributing to the problem. Future regulation and enforcement of the new PM2.5 standard will affect many power plants, especially coal-fueled power plants, and all plants in non-attainment areas.

- *Ozone.* The EPA is scheduled to propose a revision of their existing NAAQS for ozone in 2013. Significant additional emission control expenditures will likely be required at coal-fueled power plants to meet the new NAAQS. Nitrogen oxides, which are a byproduct of coal combustion, are classified as an ozone precursor. As a result, emissions control requirements for new and expanded coal-fueled power plants and industrial boilers will continue to become more demanding in the years ahead.

- *NOx SIP Call.* The Nitrogen Oxides State Implementation Plan (NOx SIP) Call program was established by the EPA in October 1998 to reduce the transport of ozone on prevailing winds from the Midwest and South to states in the Northeast, which said that they could not meet federal air quality standards because of migrating pollution. The program was designed to reduce nitrous oxide emissions by one million tons per year in 22 eastern states and the District of Columbia. Phase II reductions were required by May 2007. As a result of the program, many power plants were required to install additional emission control measures, such as selective catalytic reduction devices. Installation of additional emission control measures has made it more costly to operate coal-fueled power plants, which could make coal a less attractive fuel.

- *Clean Air Interstate Rule.* The EPA finalized the Clean Air Interstate Rule, which we refer to as CAIR, in March 2005. CAIR called for power plants in 28 Eastern states and the District of Columbia to reduce emission levels of sulfur dioxide and nitrous oxide pursuant to a cap and trade program similar to the system now in effect for acid deposition control and to that proposed by the Clean Skies Initiative.

  In July 2008, in *State of North Carolina v. EPA* and consolidated cases, the U.S. Court of Appeals for the District of Columbia Circuit disagreed with the EPA's reading of the Clean Air Act and vacated CAIR in its entirety. In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit revised its remedy and remanded the rule to the EPA. The EPA proposed a revised transport rule on August 2, 2010 (75 Fed Reg 45209) and received thousands of comments on the proposal. The rule was finalized as the Cross State Air Pollution Rule (CSAPR) on July 6, 2011, with compliance required for SO2 reductions beginning January 1, 2012 and compliance with NOx reductions required by May 1, 2012. Numerous appeals of the rule were filed and, on August 21, 2012, the Federal Court of Appeals for the District of Columbia Circuit vacated the rule, leaving the EPA to continue implementation of the CAIR Controls required under the CAIR may affect the market for coal inasmuch as multiple existing coal fired units are being retired rather than having required controls installed.

- *Mercury.* In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA's Clean Air Mercury Rule (CAMR) and remanded it to the EPA for reconsideration. In response to the vacatur, the EPA announced an EGU Mercury and Air Toxics Standard (MATS) on December 16, 2011. The MATS was finalized April 16, 2012. In addition, before the court decision vacating the CAMR, some states had either adopted the CAMR or adopted state-specific rules to regulate mercury emissions from power plants that are more stringent than the CAMR. The result of the EGU MATS and state mercury and air toxics controls is that these rules may adversely affect the demand for coal.

- *Regional Haze.* The EPA has initiated a regional haze program designed to protect and improve visibility at and around national parks, national wilderness areas and international parks, particularly those located in the southwest and southeast United States. Under the Regional Haze Rule, affected states were required to submit regional haze SIP's by December 17, 2007, that, among other things, was to identify facilities that would have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and the EPA issued a Finding of Failure to Submit plans on January 15, 2009 (74 Fed. Reg. 2392). The EPA had taken no enforcement action against states to finalize implementation plans and was slowly dealing with the state Regional Haze SIPs that were submitted, which resulted in the National Parks Conservation Association commencing litigation in the D. C. Circuit Court of Appeals on August 3, 2012, against the EPA for failure to enforce the rule *(National Parks Conservation Act v. EPA, D.C.Cir)*. Industry groups, including the Utility Air Regulatory Group have intervened *(Utility Air Regulatory Group v. EPA. D.C. Cir 12-1342, 8/6/2012*) This program may result in additional emissions restrictions from new coal-fueled power plants whose operations may impair visibility at and around federally protected areas. This program may also require certain existing coal-fueled power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxides, volatile organic chemicals and particulate matter. These limitations could affect the future market for coal.

- *New Source Review.* A number of pending regulatory changes and court actions are affecting the scope of the EPA's new source review program, which under certain circumstances requires existing coal-fueled power plants to install the more stringent air emissions control equipment required of new plants. The new source review program is continually revised and such revisions may impact demand for coal nationally, but we are unable to predict the magnitude of the impact.

Climate Change. One by-product of burning coal is carbon dioxide, which is considered a greenhouse gas and is a major source of concern with respect to global warming. In November 2004, Russia ratified the Kyoto Protocol to the 1992 Framework Convention on Global Climate Change, which establishes a binding set of emission targets for greenhouse gases. With Russia's acceptance, the Kyoto Protocol became binding on all those countries that had ratified it in February 2005. The United States has refused to ratify the Kyoto Protocol. Although the Kyoto Protocol targets varied from country to country, the United States Kyoto Protocol target reductions of greenhouse gas emissions would be to 93% of 1990 levels. Following the Kyoto meeting, multiple Conferences of the Parties have been held. None to date, including the most recent Conference of the Parties in Abu Dhabi, in January 2013, have resulted in any mandatory reduction requirements for the United States, but any such future conference may do so.

Future regulation of greenhouse gases in the United States could occur pursuant to future U.S. treaty obligations, statutory or regulatory changes under the Clean Air Act, federal or state adoption of a greenhouse gas regulatory scheme, or otherwise. The U.S. Congress has considered various proposals to reduce greenhouse gas emissions, but to date, none have become law. In April 2007, the U.S. Supreme Court rendered its decision in *Massachusetts v. EPA*, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. On December 15, 2009, the EPA published a formal determination that six greenhouse gases, including carbon dioxide and methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, the EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although *Massachusetts v. EPA* did not involve the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the EPA has since proposed regulations of stationary source greenhouse gas emissions.

In addition to the federal regulation, many states and regions have adopted greenhouse gas initiatives. These state and regional climate change rules will likely require additional controls on coal-fueled power plants and industrial boilers and may even cause some users of coal to switch from coal to a lower carbon fuel. There can be no assurance at this time that a carbon dioxide cap and trade program, a carbon tax or other regulatory regime, if implemented by the states in which our customers operate or at the federal level, will not affect the future market for coal in those regions. Increased efforts to control greenhouse gas emissions could result in reduced demand for coal.

Clean Water Act. The federal Clean Water Act (sometimes shortened to CWA) and corresponding state and local laws and regulations affect coal mining operations by restricting the discharge of pollutants, including dredged and fill materials, into waters of the United States. The Clean Water Act provisions and associated state and federal regulations are complex and subject to amendments, legal challenges and changes in implementation. Recent court decisions and regulatory actions have created uncertainty over Clean Water Act jurisdiction and permitting requirements that could variously increase or decrease the cost and time we expend on Clean Water Act compliance.

Clean Water Act requirements that may directly or indirectly affect our operations include the following:

- *Water Discharge.* Section 402 of the Clean Water Act creates a process for establishing effluent limitations for discharges to streams that are protective of water quality standards through the National Pollutant Discharge Elimination System, which we refer to as the NPDES, or an equally stringent program delegated to a state regulatory agency. Regular monitoring, reporting and compliance with performance standards are preconditions for the issuance and renewal of NPDES permits that govern discharges into waters of the United States, especially on selenium, sulfate and specific conductance. Discharges that exceed the limits specified under NPDES permits can lead to the imposition of penalties, and persistent non-compliance could lead to significant penalties, compliance costs and delays in coal production. In addition, the imposition of future restrictions on the discharge of certain pollutants into waters of the United States could increase the difficulty of obtaining and complying with NPDES permits, which could impose additional time and cost burdens on our operations. You should see Item 3—Legal Proceedings for more information about certain regulatory actions pertaining to our operations.

  Discharges of pollutants into waters that states have designated as impaired (i.e., as not meeting present water quality standards) are subject to Total Maximum Daily Load, which we refer to as TMDL, regulations. The TMDL regulations establish a process for calculating the maximum amount of a pollutant that a water body can receive while maintaining state water quality standards. Pollutant loads are allocated among the various sources that discharge pollutants into that water body. Mine operations that discharge into water bodies designated as impaired will be required to meet new TMDL allocations. The adoption of more stringent TMDL-related allocations for our coal mines could require more costly water treatment and could adversely affect our coal production.

  The Clean Water Act also requires states to develop anti-degradation policies to ensure that non-impaired water bodies continue to meet water quality standards. The issuance and renewal of permits for the discharge of pollutants to waters that have been designated as "high quality" are subject to anti-degradation review that may increase the costs, time and difficulty associated with obtaining and complying with NPDES permits.

- *Dredge and Fill Permits.* Many mining activities, such as the development of refuse impoundments, fresh water impoundments, refuse fills, valley fills, and other similar structures, may result in impacts to waters of the United States, including wetlands, streams and, in certain instances, man-made conveyances that have a hydrologic connection to such streams or wetlands. Under the Clean Water Act, coal companies are required to obtain a Section 404 permit from the Army Corps of Engineers, which we refer to as the Corps, prior to conducting such mining activities. The Corps is authorized to issue general "nationwide" permits for specific categories of activities that are similar in nature and that are determined to have minimal adverse effects on the environment. Permits issued pursuant to Nationwide Permit 21, which we refer to as NWP 21, generally authorize the disposal of dredged and fill material from surface coal mining activities into waters of the United States, subject to certain restrictions. Since March 2007, permits under NWP 21 were reissued for a five-year period with new provisions intended to strengthen environmental protections. There must be appropriate mitigation in accordance with nationwide general permit conditions rather than less restricted state-required mitigation requirements, and permitholders must receive explicit authorization from the Corps before proceeding with proposed mining activities.

Notwithstanding the additional environmental protections designed in the NWP 21, on July 15, 2009, the Corps proposed to immediately suspend the use of NWP 21 in six Appalachian states, including West Virginia, Kentucky and Virginia where the Company conducts operations.. On June 17, 2010, the Corps announced that it had suspended the use of NWP 21 in the same six states although it remained for use elsewhere. In February 2012, the Corps proposed to reissue NWP 21, albeit with significant restrictions on the acreage and length of stream channel that can be filled in the course of mining operations. The Corps' decisions regarding the use of NWP 21 does not prevent the Company's operations from seeking an individual permit under § 404 of the CWA, nor does it restrict an operation from utilizing another version of the nationwide permit, NWP 50, authorized for small underground coal mines that must construct fills as part of their mining operations.

The use of nationwide permits to authorize stream impacts from mining activities has been the subject of significant litigation. Refer to Item 3—Legal Proceedings for more information about certain litigation pertaining to our permits.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, may affect coal mining operations through its requirements for the management, handling, transportation and disposal of hazardous wastes. Currently, certain coal mine wastes, such as overburden and coal cleaning wastes, are exempted from hazardous waste management. In addition, Subtitle C of RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In its 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion products generated at electric utility and independent power producing facilities, such as coal ash, and left the exemption in place. In May 2000, the EPA concluded that coal combustion products do not warrant regulation as hazardous waste under RCRA and again retained the hazardous waste exemption for these wastes. The EPA also determined that national non-hazardous waste regulations under RCRA Subtitle D are needed for coal combustion products disposed in surface impoundments and landfills and used as mine-fill. In March of 2007 the Office of Surface Mining and the EPA proposed regulations regarding the management of coal combustion products. The EPA concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. As long as this exemption remains in effect, it is not anticipated that regulation of coal combustion waste will have any material effect on the amount of coal used by electricity generators. A final rule has not been promulgated. Most state hazardous waste laws also exempt coal combustion products, and instead treat it as either a solid waste or a special waste. Any costs associated with handling or disposal of hazardous wastes would increase our customers' operating costs and potentially reduce their ability to purchase coal. In addition, contamination caused by the past disposal of ash can lead to material liability. In another development regarding coal combustion wastes, the EPA conducted an assessment of impoundments and other units that manage residuals from coal combustion and that contain free liquids following a massive coal ash spill in Tennessee in 2008, the EPA contractors conducted site assessments at many impoundments and is requiring appropriate remedial action at any facility that is found to have a unit posing a risk for potential failure. The EPA is posting utility responses to the assessment on its web site as the responses are received. Future regulations resulting from the EPA coal combustion refuse assessments may impact the ability of the Company's utility customers to continue to use coal in their power plants.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, which we refer to as CERCLA, and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although the EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could trigger the liability provisions of the statute. Thus, coal mines that we currently own or have previously owned or operated, and sites to which we sent waste materials, may be subject to liability under CERCLA and similar state laws. In particular, we may be liable under CERCLA or similar state laws for the cleanup of hazardous substance contamination at sites where we own surface rights.

Endangered Species. The Endangered Species Act and other related federal and state statutes protect species threatened or endangered with possible extinction. Protection of threatened, endangered and other special status species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. A number of species indigenous to our properties are protected under the Endangered Species Act or other related laws or regulations. Based on the species that have been identified to date and the current application of applicable laws and regulations, however, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans. We have been able to continue our operations within the existing spatial, temporal and other restrictions associated with special status species. Should more stringent protective measures be applied to threatened, endangered or other special status species or to their critical habitat, then we could experience increased operating costs or difficulty in obtaining future mining permits.

Use of Explosives. Our surface mining operations are subject to numerous regulations relating to blasting activities. Pursuant to these regulations, we incur costs to design and implement blast schedules and to conduct pre-blast surveys and blast monitoring. In addition, the storage of explosives is subject to strict regulatory requirements established by four different federal regulatory agencies. For example, pursuant to a rule issued by the Department of Homeland Security in 2007, facilities in possession of chemicals of interest, including ammonium nitrate at certain threshold levels, must complete a screening review in order to help determine whether there is a high level of security risk such that a security vulnerability assessment and site security plan will be required.

Other Environmental Laws. We are required to comply with numerous other federal, state and local environmental laws in addition to those previously discussed. These additional laws include, for example, the Safe Drinking Water Act, the Toxic Substance Control Act and the Emergency Planning and Community Right-to-Know Act.

Employees

At February 15, 2013, we employed a total of approximately 6,424 full and part-time employees, approximately 184 of whom are represented by the Scotia Employees Association. We believe that our relations with all employees are good.

Executive Officers

The following is a list of our executive officers, their ages as of February 15, 2013 and their positions and offices during the last five years:

Name	Age	Position
Kenneth D. Cochran	52	Mr. Cochran has served as our Senior Vice President—Operations since August 2012. From May 2011 to August 2012, Mr. Cochran served as Group President of our western operations, which included Thunder Basin Coal Company, the Arch Western Bituminous Group, Arch of Wyoming and the Otter Creek development, and served as President and General Manager of Thunder Basin Coal Company from 2005 to April 2011. Prior to joining Arch Coal in 2005, Mr. Cochran spent 20 years with TXU Corporation. Mr. Cochran currently serves on the boards of Millennium Bulk Terminals-Longview, LLC, Knight Hawk Coal Company, and Tongue River Holding Company.
John T. Drexler	43	Mr. Drexler has served as our Senior Vice President and Chief Financial Officer since April 2008. Mr. Drexler served as our Vice President—Finance and Accounting from 2006 to April 2008. From 2005 to 2006, Mr. Drexler served as our Director of Planning and Forecasting. Prior to March 2005, Mr. Drexler held several other positions within our finance and accounting department.
John W. Eaves	55	Mr. Eaves currently serves as our President and Chief Executive Officer. Mr. Eaves served as our President and Chief Operating Officer from 2006 until he was appointed as Chief Executive Officer in April 2012. From 2002 to 2006, Mr. Eaves served as our Executive Vice President and Chief Operating Officer. Mr. Eaves is currently the chairman of the National Coal Council, and also serves on the boards of COALOGIX, National Mining Association, the Business Roundtable, the American Coalition for Clean Coal Electricity and the Business Council.
Robert G. Jones	56	Mr. Jones has served as our Senior Vice President—Law, General Counsel and Secretary since August 2008. Mr. Jones served as Vice President—Law, General Counsel and Secretary from 2000 to August 2008.
Paul A. Lang	52	Mr. Lang has served as our Executive Vice President and Chief Operating Officer since April 2012 and as our Executive Vice President—Operations from August 2011 to April 2012. Mr. Lang served as Senior Vice President—Operations from 2006 through August 2011, as President of Western Operations from 2005 through 2006 and President and General Manager of Thunder Basin Coal Company from 1998 to 2005.
Deck S. Slone	49	Mr. Slone has served as our Senior Vice President—Strategy and Public Policy since June 2012. Mr. Slone served as our Vice President—Government, Investor and Public Affairs from August 2008 to June 2012. Mr. Slone served as our Vice President—Investor Relations and Public Affairs from 2001 to August 2008.
Jeffrey W. Strobel	50	Mr. Strobel has served as our Vice President of Business Development and Strategy since October, 2011. Prior to joining Arch Coal, Mr. Strobel held the following positions: Director of Energy Investment Banking for Wells Fargo Securities, LLC, from 2008 to 2011; Director of Energy Investment Banking for Wachovia Capital Markets, LLC, from 2007 to 2008; and Director, Vice President and Associate for A.G. Edwards Capital Markets from 2000 to 2007.

Name	Age	Position
John A. Ziegler, Jr.	46	Mr. Ziegler has served as our Vice President—Human Resources since April 2012. From October 2011 to April 2012, Mr. Ziegler served as our Senior Director—Compensation and Benefits. From 2005 to October 2011 Mr. Ziegler served as Vice President—Contract Administration of Arch Coal Sales Company, as well as its Senior Vice President of Marketing Administration, Senior Vice President, and President. Mr. Ziegler joined Arch Coal in 2002 as Director—Internal Audit. Prior to joining Arch Coal, Mr. Ziegler held various finance and accounting positions with bioMerieux and Ernst & Young.

Available Information

We file annual, quarterly and current reports, and amendments to those reports, proxy statements and other information with the Securities and Exchange Commission. You may access and read our filings without charge through the SEC's website, at sec.gov. You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

We also make the documents listed above available without charge through our website, *archcoal.com*, as soon as practicable after we file or furnish them with the SEC. You may also request copies of the documents, at no cost, by telephone at (314) 994-2700 or by mail at Arch Coal, Inc., One CityPlace Drive, Suite 300, St. Louis, Missouri, 63141 Attention: Senior Vice President—Strategy and Public Policy. The information on our website is not part of this Annual Report on Form 10-K.

GLOSSARY OF SELECTED MINING TERMS

Certain terms that we use in this document are specific to the coal mining industry and may be technical in nature. The following is a list of selected mining terms and the definitions we attribute to them.

Assigned reserves	Recoverable reserves designated for mining by a specific operation.
Brown coal	Coal of gross calorific value of less than 5700 kilocalories per kilogramme (kcal/kg), which includes lignite and sub-bituminous coal where lignite has a gross calorific value of less than 4165 kcal/kg and sub-bituminous coal has a gross calorific value between 4165 kcal/kg and 5700 kcal/kg.
Btu	A measure of the energy required to raise the temperature of one pound of water one degree of Fahrenheit.
Compliance coal	Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million Btus, requiring no blending or other sulfur dioxide reduction technologies in order to comply with the requirements of the Clean Air Act.
Continuous miner	A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.
Dragline	A large machine used in surface mining to remove the overburden, or layers of earth and rock, covering a coal seam. The dragline has a large bucket, suspended by cables from the end of a long boom, which is able to scoop up large amounts of overburden as it is dragged across the excavation area and redeposit the overburden in another area.
Hard coal	Coal of gross calorific value greater than 5700 kcal/kg on an ashfree but moist basis and further disaggregated into anthracite, coking coal and other bituminous coal.
Longwall mining	One of two major underground coal mining methods, generally employing two rotating drums pulled mechanically back and forth across a long face of coal.

Low-sulfur coal	Coal which, when burned, emits 1.6 pounds or less of sulfur dioxide per million Btus.
Preparation plant	A facility used for crushing, sizing and washing coal to remove impurities and to prepare it for use by a particular customer.
Probable reserves	Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced.
Proven reserves	Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.
Reclamation	The restoration of land and environmental values to a mining site after the coal is extracted. The process commonly includes "recontouring" or shaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers.
Recoverable reserves	The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.
Reserves	That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.
Room-and-pillar mining	One of two major underground coal mining methods, utilizing continuous miners creating a network of "rooms" within a coal seam, leaving behind "pillars" of coal used to support the roof of a mine.
Unassigned reserves	Recoverable reserves that have not yet been designated for mining by a specific operation.

ITEM 1A. RISK FACTORS.

Our business involves certain risks and uncertainties. In addition to the risks and uncertainties described below, we may face other risks and uncertainties, some of which may be unknown to us and some of which we may deem immaterial. If one or more of these risks or uncertainties occur, our business, financial condition or results of operations may be materially and adversely affected.

Risks Related to Our Operations

Coal prices are subject to change and a substantial or extended decline in prices could materially and adversely affect our profitability and the value of our coal reserves.

Our profitability and the value of our coal reserves depend upon the prices we receive for our coal. The contract prices we may receive in the future for coal depend upon factors beyond our control, including the following:

- the domestic and foreign supply and demand for coal;
- the domestic and foreign demand for electricity and steel;
- the quantity and quality of coal available from competitors;
- competition for production of electricity from non-coal sources, including the price and availability of alternative fuels;
- domestic and foreign air emission standards for coal-fueled power plants and the ability of coal-fueled power plants to meet these standards;
- adverse weather, climatic or other natural conditions, including unseasonable weather patterns;
- domestic and foreign economic conditions, including economic slowdowns;
- domestic and foreign legislative, regulatory and judicial developments, environmental regulatory changes or changes in energy policy and energy conservation measures that would adversely affect the coal industry, such as legislation limiting carbon emissions or providing for increased funding and incentives for alternative energy sources;
- the proximity to, capacity of and cost of transportation and port facilities; and
- market price fluctuations for sulfur dioxide emission allowances.

A substantial or extended decline in the prices we receive for our future coal sales contracts could materially and adversely affect us by decreasing our profitability and the value of our coal reserves.

Our coal mining operations are subject to operating risks that are beyond our control, which could result in materially increased operating expenses and decreased production levels and could materially and adversely affect our profitability.

We mine coal at underground and surface mining operations. Certain factors beyond our control, including those listed below, could disrupt our coal mining operations, adversely affect production and shipments and increase our operating costs:

- poor mining conditions resulting from geological, hydrologic or other conditions that may cause instability of highwalls or spoil piles or cause damage to nearby infrastructure or mine personnel;
- a major incident at the mine site that causes all or part of the operations of the mine to cease for some period of time;
- mining, processing and plant equipment failures and unexpected maintenance problems;

- adverse weather and natural disasters, such as heavy rains or snow, flooding and other natural events affecting operations, transportation or customers;
- unexpected or accidental surface subsidence from underground mining;
- accidental mine water discharges, fires, explosions or similar mining accidents; and
- competition and/or conflicts with other natural resource extraction activities and production within our operating areas, such as coalbed methane extraction or oil and gas development.

If any of these conditions or events occurs, particularly at our Black Thunder mining complex, which accounted for approximately 70% of the coal volume we sold in 2012, our coal mining operations may be disrupted and we could experience a delay or halt of production or shipments or our operating costs could increase significantly. In addition, if our insurance coverage is limited or excludes certain of these conditions or events, then we may not be able to recover any of the losses we may incur as a result of such conditions or events, some of which may be substantial.

Competition could put downward pressure on coal prices and, as a result, materially and adversely affect our revenues and profitability.

We compete with numerous other domestic and foreign coal producers for domestic and international sales. Overcapacity and increased production within the coal industry, both domestically and internationally, could materially reduce coal prices and therefore materially reduce our revenues and profitability. In addition, our ability to ship our coal to international customers depends on port capacity, which is limited. Increased competition within the coal industry for international sales could result in us not being able to obtain throughput capacity at port facilities, or the rates for such throughput capacity to increase to a point where it is not economically feasible to export our coal.

In addition to competing with other coal producers, we compete generally with producers of other fuels, such as natural gas. A decline in the price of natural gas, or sustained low natural gas prices, could cause demand for coal to decrease and adversely affect the price of our coal. For example, the average wellhead price of natural gas in 2012 was $2.52 (EIA, Jan-Oct 2012), compared to $4.48 and $3.95 in 2010 and 2011, respectively, leading to, in some instances, fuel switching and decreased coal consumption by electricity-generating utilities. Sustained low natural gas prices may also cause utilities to phase out or close existing coal-fired power plants or reduce construction of any new coal-fired power plants, which could have a material adverse effect on demand and prices for our coal.

Unfavorable economic and market conditions could adversely affect our revenues and profitability.

The recent global economic recession and credit market tightening has had a negative impact on both the coal industry and on various customers. If any of these conditions persist or worsen, or if there are downturns in economic conditions, our business, financial condition or results of operations could be adversely affected. During unfavorable economic conditions we are focused on cost control and capital discipline, but there can be no assurance that these actions, or any other actions that we may take, will be sufficient to offset any adverse affect these conditions may have on our business, financial condition or results of operations.

Any change in the coal consumption of electric power generators could result in less demand and lower prices for coal, which could materially and adversely affect our revenues and results of operations.

Thermal coal accounted for the majority of our coal sales during 2012. The majority of these sales were to electric power generators. The amount of coal consumed for electric power generation is affected primarily by the overall demand for electricity, the availability, quality and price of competing fuels for power generation and governmental regulations. Gas-fueled generation has the potential to displace coal-fueled generation, particularly from older, less efficient coal-powered generators. We expect that many of the new power plants needed in the

United States to meet increasing demand for electricity generation will be fueled by natural gas because gas-fired plants are cheaper to construct and permits to construct these plants are easier to obtain as natural gas is seen as having a lower environmental impact than coal-fueled generators. In addition, state and federal mandates for increased use of electricity from renewable energy sources could have an impact on the market for our coal. Several states have enacted legislative mandates requiring electricity suppliers to use renewable energy sources to generate a certain percentage of power. There have been numerous proposals to establish a similar uniform, national standard although none of these proposals have been enacted to date. Possible advances in technologies and incentives, such as tax credits, to enhance the economics of renewable energy sources could make these sources more competitive with coal. Any reduction in the amount of coal consumed by electric power generators could reduce the price of coal that we mine and sell, thereby reducing our revenues and materially and adversely affecting our business and results of operations.

A decline in demand for metallurgical coal would limit our ability to sell our coal into higher-priced metallurgical markets and could substantially affect our business.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the metallurgical and steam coal markets. We decide whether to mine, process and market these coals as metallurgical or steam coal based on management's assessment as to which market is likely to provide us with a higher margin. We consider a number of factors when making this assessment, including the difference between the current and anticipated future market prices of steam coal and metallurgical coal and the increased costs incurred in producing coal for sale in the metallurgical market instead of the steam market. A decline in the metallurgical market relative to the steam market could cause us, as well as our competitors, to shift coal from the metallurgical market to the steam market, thereby reducing our revenues and profitability and increasing the availability of coal to customers in the steam market.

Our inability to acquire additional coal reserves or our inability to develop coal reserves in an economically feasible manner may adversely affect our business.

Our profitability depends substantially on our ability to mine and process, in a cost-effective manner, coal reserves that possess the quality characteristics desired by our customers. As we mine, our coal reserves decline. As a result, our future success depends upon our ability to acquire additional coal that is economically recoverable. If we fail to acquire or develop additional coal reserves, our existing reserves will eventually be depleted. We may not be able to obtain replacement reserves when we require them. If available, replacement reserves may not be available at favorable prices, or we may not be capable of mining those reserves at costs that are comparable with our existing coal reserves. Our ability to obtain coal reserves in the future could also be limited by the availability of cash we generate from our operations or available financing, restrictions under our existing or future financing arrangements, and competition from other coal producers, the lack of suitable acquisition or lease-by-application, or LBA, opportunities or the inability to acquire coal properties or LBAs on commercially reasonable terms. If we are unable to acquire replacement reserves, our future production may decrease significantly and our operating results may be negatively affected. In addition, we may not be able to mine future reserves as profitably as we do at our current operations.

Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs.

Our future performance depends on, among other things, the accuracy of our estimates of our proven and probable coal reserves. We base our estimates of reserves on engineering, economic and geological data assembled, analyzed and reviewed by internal and third-party engineers and consultants. We update our estimates of the quantity and quality of proven and probable coal reserves annually to reflect the production of coal from the reserves, updated geological models and mining recovery data, the tonnage contained in new lease areas acquired and estimated costs of production and sales prices. There are numerous factors and assumptions inherent in estimating the quantities and qualities of, and costs to mine, coal reserves, including many factors beyond our control, including the following:

- quality of the coal;
- geological and mining conditions, which may not be fully identified by available exploration data and/or may differ from our experiences in areas where we currently mine;
- the percentage of coal ultimately recoverable;
- the assumed effects of regulation, including the issuance of required permits, taxes, including severance and excise taxes and royalties, and other payments to governmental agencies;
- assumptions concerning the timing for the development of the reserves; and
- assumptions concerning equipment and productivity, future coal prices, operating costs, including for critical supplies such as fuel, tires and explosives, capital expenditures and development and reclamation costs.

As a result, estimates of the quantities and qualities of economically recoverable coal attributable to any particular group of properties, classifications of reserves based on risk of recovery, estimated cost of production, and estimates of future net cash flows expected from these properties as prepared by different engineers, or by the same engineers at different times, may vary materially due to changes in the above factors and assumptions. Actual production recovered from identified reserve areas and properties, and revenues and expenditures associated with our mining operations, may vary materially from estimates. Any inaccuracy in our estimates related to our reserves could result in decreased profitability from lower than expected revenues and/or higher than expected costs.

Increases in the costs of mining and other industrial supplies, including steel-based supplies, diesel fuel and rubber tires, or the inability to obtain a sufficient quantity of those supplies, could negatively affect our operating costs or disrupt or delay our production.

Our coal mining operations use significant amounts of steel, diesel fuel, explosives, rubber tires and other mining and industrial supplies. The cost of roof bolts we use in our underground mining operations depend on the price of scrap steel. We also use significant amounts of diesel fuel and tires for the trucks and other heavy machinery we use, particularly at our Black Thunder mining complex. If the prices of mining and other industrial supplies, particularly steel-based supplies, diesel fuel and rubber tires, increase, our operating costs could be negatively affected. In addition, if we are unable to procure these supplies, our coal mining operations may be disrupted or we could experience a delay or halt in our production.

Disruptions in the quantities of coal produced by our contract mine operators or purchased from other third parties could temporarily impair our ability to fill customer orders or increase our operating costs.

We use independent contractors to mine coal at certain of our mining complexes, including select operations in our Appalachian segment. In addition, we purchase coal from third parties that we sell to our customers. Operational difficulties at contractor-operated mines or mines operated by third parties from whom we purchase coal, changes in demand for contract miners from other coal producers and other factors beyond our control could affect the availability, pricing, and quality of coal produced for or purchased by us. Disruptions in the quantities of coal produced for or purchased by us could impair our ability to fill our customer orders or require us to purchase coal from other sources in order to satisfy those orders. If we are unable to fill a customer order or if we are required to purchase coal from other sources in order to satisfy a customer order, we could lose existing customers and our operating costs could increase.

Our ability to collect payments from our customers could be impaired if their creditworthiness deteriorates.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If we determine that a customer is not creditworthy, we may not be required to deliver coal under the customer's coal sales contract. If this occurs, we may decide to sell the customer's coal on the spot market, which may be at prices lower than the contracted price, or we may be unable to sell the coal at all. Furthermore, the bankruptcy of any of our customers could materially and adversely affect our financial position.

In addition, our customer base may change with deregulation as utilities sell their power plants to their non-regulated affiliates or third parties that may be less creditworthy, thereby increasing the risk we bear for customer payment default. Some power plant owners may have credit ratings that are below investment grade, or may become below investment grade after we enter into contracts with them. In addition, competition with other coal suppliers could force us to extend credit to customers and on terms that could increase the risk of payment default. Customers in other countries may also be subject to other pressures and uncertainties that may affect their ability to pay, including trade barriers, exchange controls and local economic and political conditions.

A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs.

We conduct a significant part of our coal mining operations on properties that we lease. A title defect or the loss of a lease could adversely affect our ability to mine the associated coal reserves. We may not verify title to our leased properties or associated coal reserves until we have committed to developing those properties or coal reserves. We may not commit to develop property or coal reserves until we have obtained necessary permits and completed exploration. As such, the title to property that we intend to lease or coal reserves that we intend to mine may contain defects prohibiting our ability to conduct mining operations. Similarly, our leasehold interests may be subject to superior property rights of other third parties. In order to conduct our mining operations on properties where these defects exist, we may incur unanticipated costs. In addition, some leases require us to produce a minimum quantity of coal and require us to pay minimum production royalties. Our inability to satisfy those requirements may cause the leasehold interest to terminate.

The availability, reliability and cost-effectiveness of transportation facilities and fluctuations in transportation costs could affect the demand for our coal or impair our ability to supply coal to our customers.

We depend upon barge, ship, rail, truck and belt transportation systems, as well as seaborne vessels and port facilities, to deliver coal to our customers. Disruptions in transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events beyond our control could impair our ability to supply coal to our customers. Since we do not have long-term contracts with all transportation providers we utilize, decreased performance levels over longer periods of time could cause our customers to look to other sources for their coal needs. In addition, increases in transportation costs, including the price of gasoline and diesel fuel, could make coal a less competitive source of energy when compared to alternative fuels or could make coal produced in one region of the United States less competitive than coal produced in other regions of the United States or abroad. If we experience disruptions in our transportation services or if transportation costs increase significantly and we are unable to find alternative transportation providers, our coal mining operations may be disrupted, we could experience a delay or halt of production or our profitability could decrease significantly.

In addition, a growing portion of our coal sales in recent years has been into export markets, and we are actively seeking additional international customers. Our ability to maintain and grow our export sales revenue and margins depends on a number of factors, including the existence of sufficient and cost-effective export terminal capacity for the shipment of coal to foreign markets. At present, there is limited terminal capacity for the export of coal into foreign markets. Our access to existing and any future terminal capacity may be adversely affected by regulatory and permit requirements, environmental and other legal challenges, public perceptions and resulting political pressures, operational issues at terminals and competition among domestic coal producers for access to limited terminal capacity, among other factors. If we are unable to maintain terminal capacity, or are unable to access additional future terminal capacity for the export of our coal on commercially reasonable terms, or at all, our results could be materially and adversely affected.

From time to time we enter into "take-or-pay" contracts for rail and port capacity related to our export sales. These contracts require us to pay for a minimum quantity of coal to be transported on the railway or through the port regardless of whether we sell and ship any coal. If we fail to acquire sufficient export sales to meet our minimum obligations under these contracts we are still obligated to make payments to the railway or port facility, which could have a negative impact on our cash flows, profitability and results of operations.

Our profitability depends upon the long-term coal supply agreements we have with our customers. Changes in purchasing patterns in the coal industry could make it difficult for us to extend our existing long-term coal supply agreements or to enter into new agreements in the future.

We sell a portion of our coal under long-term coal supply agreements, which we define as contracts with terms greater than one year. Under these arrangements, we fix the prices of coal shipped during the initial year and may adjust the prices in later years. As a result, at any given time the market prices for similar-quality coal may exceed the prices for coal shipped under these arrangements. Changes in the coal industry may cause some of our customers not to renew, extend or enter into new long-term coal supply agreements with us or to enter into agreements to purchase fewer tons of coal than in the past or on different terms or prices. In addition, uncertainty caused by federal and state regulations, including the Clean Air Act, could deter our customers from entering into long-term coal supply agreements.

Because we sell a portion of our coal production under long-term coal supply agreements, our ability to capitalize on more favorable market prices may be limited. Conversely, at any given time we are subject to fluctuations in market prices for the quantities of coal that we have produced or plan to produce but which we have not committed to sell. As described above under "A substantial or extended decline in coal prices could negatively affect our profitability and the value of our coal reserves," the market prices for coal may be volatile and may depend upon factors beyond our control. Our profitability may be adversely affected if we are unable to sell uncommitted production at favorable prices or at all.

Our long-term coal supply agreements typically contain *force majeure* provisions allowing the parties to temporarily suspend performance during specified events beyond their control. Most of our long-term coal supply agreements also contain provisions requiring us to deliver coal that satisfies certain quality specifications, such as heat value, sulfur content, ash content, hardness and ash fusion temperature. These provisions in our long-term coal supply agreements could result in negative economic consequences to us, including price adjustments, purchasing replacement coal in a higher-priced open market, the rejection of deliveries or, in the extreme, contract termination. Our profitability may be negatively affected if we are unable to seek protection during adverse economic conditions or if we incur financial or other economic penalties as a result of these provisions of our long-term supply agreements. For more information about our long-term coal supply agreements, you should see the section entitled "Long-Term Coal Supply Arrangements."

The loss of, or significant reduction in, purchases by our largest customers could adversely affect our profitability.

For the year ended December 31, 2012, we derived approximately 16% of our total coal revenues from sales to our three largest customers and approximately 36% of our total coal revenues from sales to our ten largest customers. We are currently discussing the extension of coal sales agreements with some of these customers. However, we may be unsuccessful in obtaining coal supply agreements with those customers, and some or all of these customers could discontinue purchasing coal from us. If any of those customers, particularly any of our three largest customers, was to significantly reduce the quantities of coal it purchases from us, or if we are unable to sell coal to those customers on terms as favorable to us, it may have an adverse impact on the results of our business.

Failure to obtain or renew surety bonds on acceptable terms could affect our ability to secure reclamation and coal lease obligations and, therefore, our ability to mine or lease coal.

Federal and state laws require us to obtain surety bonds or post letters of credit to secure performance or payment of certain long-term obligations, such as mine closure or reclamation costs, federal and state workers' compensation costs, coal leases and other obligations. We may have difficulty procuring or maintaining our surety bonds. Our bond issuers may demand higher fees, additional collateral, including letters of credit or other terms less favorable to us upon renewal of bonds. Because we are required by state and federal law to have these bonds in place before mining can commence or continue, our failure to maintain surety bonds, letters of credit or other guarantees or security arrangements would materially and adversely affect our ability to mine or lease coal. That failure could result from a variety of factors, including lack of availability, higher expense or unfavorable market terms, the exercise by third party surety bond issuers of their right to refuse to renew the surety and restrictions on availability of collateral for current and future third party surety bond issuers under the terms of our financing arrangements.

Under certain circumstances, we could be responsible for certain retiree medical benefits assumed by Magnum Coal Company.

On December 31, 2005, Arch entered into a purchase and sale agreement with Magnum Coal Company to sell certain assets. On July 23, 2008, Patriot Coal Corporation ("Patriot") acquired Magnum Coal Company. On July 9, 2012, Patriot and certain of its wholly owned subsidiaries, including Magnum Coal Company, filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York. Should Patriot not emerge from bankruptcy, or if it is incapable of paying retiree medical benefits pursuant to Section 9711 of the Coal Industry Retiree Health Benefit Act of 1992 to a certain subset of retirees, we could become responsible for certain of their retiree medical obligations for retirees of Magnum who retired prior to October 1, 1994. We do not have the necessary information to perform an actuarial estimate of the cost of such benefits.

We may incur losses as a result of certain marketing, trading and asset optimization strategies.

We seek to optimize our coal production and leverage our knowledge of the coal industry through a variety of marketing, trading and other asset optimization strategies. We maintain a system of complementary processes and controls designed to monitor and control our exposure to market and other risks as a consequence of these strategies. These processes and controls seek to balance our ability to profit from certain marketing, trading and asset optimization strategies with our exposure to potential losses. While we employ a variety of risk monitoring and mitigation techniques, those techniques and accompanying judgments cannot anticipate every potential outcome or the timing of such outcomes. In addition, the processes and controls that we use to manage our exposure to market and other risks resulting from these strategies involve assumptions about the degrees of correlation or lack thereof among prices of various assets or other market indicators. These correlations may change significantly in times of market turbulence or other unforeseen circumstances. As a result, we may experience volatility in our earnings as a result of our marketing, trading and asset optimization strategies.

Recent international growth in our operations adds new and unique risks to our business.

We have recently opened offices in Singapore and the United Kingdom. The international expansion of our operations increases our exposure to country and currency risks. In addition, our international offices are selling our coal to new customers and customers in new countries, whose business practices and reputations are not as well known to us. We are also challenged by political risks by expanding internationally, including the potential for expropriation of assets and limits on the repatriation of earnings. In the event that we are unable to effectively manage these new risks, our results of operations, financial position or cash flow could be adversely affected by these activities.

Risks Related to Our Indebtedness

The amount of indebtedness we have incurred could significantly affect our business.

At December 31, 2012, we had consolidated indebtedness of approximately $5.1 billion. We also have significant lease and royalty obligations. Our ability to satisfy our debt, lease and royalty obligations, and our ability to refinance our indebtedness, will depend upon our future operating performance. Our ability to satisfy our financial obligations may be adversely affected if we incur additional indebtedness in the future. In addition, the amount of indebtedness we have incurred could have significant consequences to us, such as:

- limiting our ability to obtain additional financing to fund growth, such as new LBA acquisitions or other mergers and acquisitions, working capital, capital expenditures, debt service requirements or other cash requirements;
- exposing us to the risk of increased interest costs if the underlying interest rates rise;
- limiting our ability to invest operating cash flow in our business due to existing debt service requirements;
- making it more difficult to obtain surety bonds, letters of credit or other financing, particularly during weak credit markets;
- causing a decline in our credit ratings;
- limiting our ability to compete with companies that are not as leveraged and that may be better positioned to withstand economic downturns;
- limiting our ability to acquire new coal reserves and/or plant and equipment needed to conduct operations; and
- limiting our flexibility in planning for, or reacting to, and increasing our vulnerability to, changes in our business, the industry in which we compete and general economic and market conditions.

If we further increase our indebtedness, the related risks that we now face, including those described above, could intensify. In addition to the principal repayments on our outstanding debt, we have other demands on our cash resources, including capital expenditures and operating expenses. Our ability to pay our debt depends upon our operating performance. In particular, economic conditions could cause our revenues to decline, and hamper our ability to repay our indebtedness. If we do not have enough cash to satisfy our debt service obligations, we may be required to refinance all or part of our debt, sell assets or reduce our spending. We may not be able to, at any given time, refinance our debt or sell assets on terms acceptable to us or at all.

We may be unable to comply with restrictions imposed by our credit facilities and other financing arrangements.

The agreements governing our outstanding financing arrangements impose a number of restrictions on us. For example, the terms of our credit facilities, leases and other financing arrangements contain financial and other covenants that create limitations on our ability to borrow the full amount under our credit facilities, effect acquisitions or dispositions and incur additional debt and require us to maintain minimum levels of liquidity and various financial ratios and comply with various other financial covenants. Our ability to comply with these restrictions may be affected by events beyond our control. A failure to comply with these restrictions could adversely affect our ability to borrow under our credit facilities or result in an event of default under these agreements. In the event of a default, our lenders and the counterparties to our other financing arrangements could terminate their commitments to us and declare all amounts borrowed, together with accrued interest and fees, immediately due and payable. If this were to occur, we might not be able to pay these amounts, or we might be forced to seek an amendment to our financing arrangements which could make the terms of these arrangements more onerous for us. As a result, a default under one or more of our existing or future financing arrangements could have significant consequences for us. For more information about some of the restrictions contained in our credit facilities, leases and other financial arrangements, you should see the section entitled "Liquidity and Capital Resources."

Risks Related to Environmental, Other Regulations and Legislation

Extensive environmental regulations, including existing and potential future regulatory requirements relating to air emissions, affect our customers and could reduce the demand for coal as a fuel source and cause coal prices and sales of our coal to materially decline.

Coal contains impurities, including but not limited to sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. The operations of our customers are subject to extensive environmental regulation particularly with respect to air emissions. For example, the federal Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. A series of more stringent requirements relating to particulate matter, ozone, haze, mercury, sulfur dioxide, nitrogen oxide and other air pollutants are expected to be proposed or become effective in coming years. In addition, concerted conservation efforts that result in reduced electricity consumption could cause coal prices and sales of our coal to materially decline.

Considerable uncertainty is associated with these air emissions initiatives. The content of regulatory requirements in the United States is in the process of being developed, and many new regulatory initiatives remain subject to review by federal or state agencies or the courts. Stringent air emissions limitations are either in place or are likely to be imposed in the short to medium term, and these limitations will likely require significant emissions control expenditures for many coal-fueled power plants. As a result, these power plants may switch to other fuels that generate fewer of these emissions or may install more effective pollution control equipment that reduces the need for low sulfur coal, possibly reducing future demand for coal and a reduced need to construct new coal-fueled power plants. The EIA's expectations for the coal industry assume there will be a significant number of as yet unplanned coal-fired plants built in the future which may not occur. Any switching of fuel sources away from coal, closure of existing coal-fired plants, or reduced construction of new plants could have a material adverse effect on demand for and prices received for our coal. Alternatively, less stringent air emissions limitations, particularly related to sulfur, to the extent enacted could make low sulfur coal less attractive, which could also have a material adverse effect on the demand for and prices received for our coal.

You should see "Environmental and Other Regulatory Matters" for more information about the various governmental regulations affecting us.

Our failure to obtain and renew permits necessary for our mining operations could negatively affect our business.

Mining companies must obtain numerous permits that impose strict regulations on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. The permitting rules, and the interpretations of these rules, are complex, change frequently and are often subject to discretionary interpretations by the regulators, all of which may make compliance more difficult or impractical, and may possibly preclude the continuance of ongoing operations or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens' lawsuits to challenge the issuance of permits, the validity of environmental impact statements or performance of mining activities. Accordingly, required permits may not be issued or renewed in a timely fashion or at all, or permits issued or renewed may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow and profitability.

Federal or state regulatory agencies have the authority to order certain of our mines to be temporarily or permanently closed under certain circumstances, which could materially and adversely affect our ability to meet our customers' demands.

Federal or state regulatory agencies have the authority under certain circumstances following significant health and safety incidents, such as fatalities, to order a mine to be temporarily or permanently closed. If this occurred, we may be required to incur capital expenditures to re-open the mine. In the event that these agencies order the closing of our mines, our coal sales contracts generally permit us to issue *force majeure* notices which suspend our obligations to deliver coal under these contracts. However, our customers may challenge our issuances of *force majeure* notices. If these challenges are successful, we may have to purchase coal from third-party sources, if it is available, to fulfill these obligations, incur capital expenditures to re-open the mines and/or negotiate settlements with the customers, which may include price reductions, the reduction of commitments or the extension of time for delivery or terminate customers' contracts. Any of these actions could have a material adverse effect on our business and results of operations.

Extensive environmental regulations impose significant costs on our mining operations, and future regulations could materially increase those costs or limit our ability to produce and sell coal.

The coal mining industry is subject to increasingly strict regulation by federal, state and local authorities with respect to environmental matters such as:

- limitations on land use;
- mine permitting and licensing requirements;
- reclamation and restoration of mining properties after mining is completed;
- management of materials generated by mining operations;
- the storage, treatment and disposal of wastes;
- remediation of contaminated soil and groundwater;
- air quality standards;
- water pollution;
- protection of human health, plant-life and wildlife, including endangered or threatened species;
- protection of wetlands;
- the discharge of materials into the environment;
- the effects of mining on surface water and groundwater quality and availability; and
- the management of electrical equipment containing polychlorinated biphenyls.

The costs, liabilities and requirements associated with the laws and regulations related to these and other environmental matters may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. We cannot assure you that we have been or will be at all times in compliance with the applicable laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. We may incur material costs and liabilities resulting from claims for damages to property or injury to persons arising from our operations. If we are pursued for sanctions, costs and liabilities in respect of these matters, our mining operations and, as a result, our profitability could be materially and adversely affected.

New legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment that would further regulate and tax the coal industry, may also require us to change operations significantly or incur increased costs. Such changes could have a material adverse effect on our financial condition and results of operations. You should see the section entitled "Environmental and Other Regulatory Matters" for more information about the various governmental regulations affecting us.

If the assumptions underlying our estimates of reclamation and mine closure obligations are inaccurate, our costs could be greater than anticipated.

SMCRA and counterpart state laws and regulations establish operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of underground mining. We base our estimates of reclamation and mine closure liabilities on permit requirements, engineering studies and our engineering expertise related to these requirements. Our management and engineers periodically review these estimates. The estimates can change significantly if actual costs vary from our original assumptions or if governmental regulations change significantly. We are required to record new obligations as liabilities at fair value under generally accepted accounting principles. In estimating fair value, we considered the estimated current costs of reclamation and mine closure and applied inflation rates and a third-party profit, as required. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The resulting estimated reclamation and mine closure obligations could change significantly if actual amounts change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial condition.

Our operations may impact the environment or cause exposure to hazardous substances, and our properties may have environmental contamination, which could result in material liabilities to us.

Our operations currently use hazardous materials and generate limited quantities of hazardous wastes from time to time. We could become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and cleanup of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

We maintain extensive coal refuse areas and slurry impoundments at a number of our mining complexes. Such areas and impoundments are subject to extensive regulation. Slurry impoundments can fail, which could release large volumes of coal slurry into the surrounding environment. Structural failure of an impoundment can result in extensive damage to the environment and natural resources, such as bodies of water that the coal slurry reaches, as well as liability for related personal injuries and property damages, and injuries to wildlife. Some of our impoundments overlie mined out areas, which can pose a heightened risk of failure and of damages arising out of failure. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental contamination and associated liability, as well as for fines and penalties.

Drainage flowing from or caused by mining activities can be acidic with elevated levels of dissolved metals, a condition referred to as "acid mine drainage," which we refer to as AMD. The treating of AMD can be costly. Although we do not currently face material costs associated with AMD, it is possible that we could incur significant costs in the future.

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us.

Judicial rulings that restrict how we may dispose of mining wastes could significantly increase our operating costs, discourage customers from purchasing our coal and materially harm our financial condition and operating results.

To dispose of mining overburden generated by our surface mining operations, we often need to obtain permits to construct and operate valley fills and surface impoundments. Some of these permits are Clean Water Act § 404 permits issued by the Army Corps of Engineers. Two of our operating subsidiaries were identified in an existing lawsuit, which challenged the issuance of such permits and asked that the Corps be ordered to rescind them. Two of our operating subsidiaries intervened in the suit to protect their interests in being allowed to operate under the issued permits, and one of them thereafter was dismissed. On February 13, 2009, the U.S. Court of Appeals for the Fourth Circuit ruled on appeals from decisions rendered prior to our intervention, which may have a favorable impact on our permits. The matter is pending before the U.S. District Court for the Southern District of West Virginia on Mingo Logan's motion for summary judgment. If the matter is resolved ultimately in a manner that is adverse to the interests of our operating subsidiaries, their operating results may be adversely impacted.

Changes in the legal and regulatory environment could complicate or limit our business activities, increase our operating costs or result in litigation.

The conduct of our businesses is subject to various laws and regulations administered by federal, state and local governmental agencies in the United States. These laws and regulations may change, sometimes dramatically, as a result of political, economic or social events or in response to significant events. Certain recent developments particularly may cause changes in the legal and regulatory environment in which we operate and may impact our results or increase our costs or liabilities. Such legal and regulatory environment changes may include changes in: the processes for obtaining or renewing permits; costs associated with providing healthcare benefits to employees; health and safety standards; accounting standards; taxation requirements; and competition laws.

For example, in April 2010, the EPA issued comprehensive guidance regarding the water quality standards that EPA believes should apply to certain new and renewed Clean Water Act permit applications for Appalachian surface coal mining operations. Under the EPA's guidance, applicants seeking to obtain state and federal Clean Water Act permits for surface coal mining in Appalachia must perform an evaluation to determine if a reasonable potential exists that the proposed mining would cause a violation of water quality standards. According to the EPA Administrator, the water quality standards set forth in the EPA's guidance may be difficult for most surface mining operations to meet. Additionally, the EPA's guidance contains requirements for the avoidance and minimization of environmental and mining impacts, consideration of the full range of potential impacts on the environment, human health and local communities, including low-income or minority populations, and provision of meaningful opportunities for public participation in the permit process. The EPA's guidance is subject to several pending legal challenges related to its legal effect and sufficiency including consolidated challenges pending in the United States Court of Appeals for the District of Columbia Circuit led by the National Mining Association. We may be required to meet these requirements in the future in order to obtain and maintain permits that are important to our Appalachian operations. We cannot give any assurance that we will be able to meet these or any other new standards.

In response to the April 2010 explosion at Massey Energy Company's Upper Big Branch Mine and the ensuing tragedy, we expect that safety matters pertaining to underground coal mining operations will continue to be the topic of new legislation and regulation, as well as the subject of heightened enforcement efforts. For example, federal and West Virginia state authorities have announced special inspections of coal mines to evaluate several safety concerns, including the accumulation of coal dust and the proper ventilation of gases such as methane. In addition, both federal and West Virginia state authorities have announced that they are considering changes to mine safety rules and regulations which could potentially result in additional or enhanced required safety equipment, more frequent mine inspections, stricter and more thorough enforcement practices and enhanced reporting requirements. Any new environmental, health and safety requirements may increase the costs associated with obtaining or maintain permits necessary to perform our mining operations or otherwise may prevent, delay or reduce our planned production, any of which could adversely affect our financial condition, results of operations and cash flows.

Further, mining companies are entitled a tax deduction for percentage depletion, which may allow for depletion deductions in excess of the basis in the mineral reserves. The deduction is currently being reviewed by the federal government for repeal. If repealed, the inability to take a tax deduction for percentage depletion could have a material impact on our financial condition, results of operations, cash flows and future tax payments.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Properties

General

At December 31, 2012, we owned or controlled primarily through long-term leases approximately 32,135 acres of coal land in Ohio, 25,104 acres of coal land in Maryland, 46,716 acres of coal land in Virginia, 418,713 acres of coal land in West Virginia, 107,641 acres of coal land in Wyoming, 267,571 acres of coal land in Illinois, 62,010 acres of coal land in Utah, 239,863 acres of coal land in Kentucky, 19,428 acres of coal land in Montana, 21,802 acres of coal land in New Mexico, and 18,443 acres of coal land in Colorado. In addition, we also owned or controlled through long-term leases smaller parcels of property in Alabama, Indiana, Washington, Arkansas, California, and Texas. We lease approximately 124,353 acres of our coal land from the federal government and approximately 36,364 acres of our coal land from various state governments. Certain of our preparation plants or loadout facilities are located on properties held under leases which expire at varying dates over the next 30 years. Most of the leases contain options to renew. Our remaining preparation plants and loadout facilities are located on property owned by us or for which we have a special use permit.

Our executive headquarters occupy approximately 92,900 square feet of leased space at One CityPlace Drive, in St. Louis, Missouri. Our subsidiaries currently own or lease the equipment utilized in their mining operations. You should see "Our Mining Operations" for more information about our mining operations, mining complexes and transportation facilities.

Our Coal Reserves

We estimate that we owned or controlled approximately 5.5 billion tons of proven and probable recoverable reserves at December 31, 2012. Our coal reserve estimates at December 31, 2012 were prepared by our engineers and geologists and reviewed by Weir International, Inc., a mining and geological consultant. Our coal reserve estimates are based on data obtained from our drilling activities and other available geologic data. Our coal reserve estimates are periodically updated to reflect past coal production and other geologic and mining data. Acquisitions or sales of coal properties will also change these estimates. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam.

Our coal reserve estimates include reserves that can be economically and legally extracted or produced at the time of their determination. In determining whether our reserves meet this standard, we take into account, among other things, our potential inability to obtain a mining permit, the possible necessity of revising a mining plan, changes in estimated future costs, changes in future cash flows caused by changes in costs required to be incurred to meet regulatory requirements and obtaining mining permits, variations in quantity and quality of coal, and varying levels of demand and their effects on selling prices. We use various assumptions in preparing our estimates of our coal reserves. You should see "Inaccuracies in our estimates of our coal reserves could result in decreased profitability from lower than expected revenues or higher than expected costs" contained under the heading "Risk Factors."

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The following tables present our estimated assigned and unassigned recoverable coal reserves at December 31, 2012:

Total Assigned Reserves
(Tons in millions)

	Total Assigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btus per lb. (1)	Reserve Control		Mining Method		Past Reserve Estimates(2)	
				<1.2	1.2 - 2.5	>2.5		Leased	Owned	Surface	Under-ground	2010	2011
Wyoming	1,636	1,607	29	1,550	86	—	8,869	1,636	—	1,636	—	1,605	1,474
Montana	—	—	—	—	—	—	—	—	—	—	—		
Utah	74	49	25	65	8	1	11,412	73	1	—	74	84	79
Colorado	80	70	10	80	—	—	11,368	80	—	—	80	64	88
Central App.	213	197	16	62	137	14	12,804	189	24	105	108	175	308
Northern App.	231	121	110	—	208	23	13,050	42	189	10	221	—	238
Illinois	18	10	8	—	—	18	10,835	17	1	—	18	—	30
Total*	2,252	2,054	198	1,757	439	56	9,858	2,037	215	1,751	501	1,928	2,217

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

(2) 2010 Past Reserve Estimates does not include former International Coal Group, Inc. operations acquired on June 15, 2011.

* Columns may not add due to rounding.

Total Unassigned Reserves
(Tons in millions)

	Total Unassigned Recoverable Reserves	Proven	Probable	Sulfur Content (lbs. per million Btus)			As Received Btus per lb.(1)	Reserve Control		Mining Method	
				<1.2	1.2 - 2.5	>2.5		Leased	Owned	Surface	Under-ground
Wyoming	481	397	84	429	52	—	9,653	371	110	306	175
Montana	1,387	1,129	258	1,387	—	—	8,603	1,387	—	1,387	—
Utah	37	22	15	34	3	—	11,175	36	1	—	37
Colorado	23	18	5	23	—	—	11,304	23	—	—	23
Central App.	404	252	152	122	204	78	13,023	340	64	60	344
Northern App.	199	98	101	3	94	102	12,896	42	157	7	192
Illinois	707	344	363	—	—	707	10,955	84	623	2	705
Total*	3,238	2,260	978	1,998	353	887	10,137	2,283	955	1,762	1,476

(1) As received Btus per lb. includes the weight of moisture in the coal on an as sold basis.

* Columns may not add due to rounding.

Federal and state legislation controlling air pollution affects the demand for certain types of coal by limiting the amount of sulfur dioxide which may be emitted as a result of fuel combustion and encourages a greater demand for low-sulfur coal. All of our identified coal reserves have been subject to preliminary coal seam analysis to test sulfur content. Of these reserves, approximately 68.4% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional 5.4% could be sold as low-sulfur coal. The balance is classified as high-sulfur coal. Most of our reserves are suitable for the domestic steam coal markets. A substantial portion of the low-sulfur and compliance coal reserves at a number of our Appalachian mining complexes may also be used as metallurgical coal.

The carrying cost of our coal reserves at December 31, 2012 was $5.2 billion, consisting of $99.2 million of prepaid royalties and a net book value of coal lands and mineral rights of $5.1 billion.

Reserve Acquisition Process

We acquire a significant portion of the coal we control in the western United States through the lease-by-application (LBA) process. Under this process, before a mining company can obtain new coal reserves, the coal tract must be nominated for lease, and the company must win the lease through a competitive bidding process. The LBA process can last anywhere from two to five years from the time the coal tract is nominated to the time a final bid is accepted by the BLM. After the LBA is awarded, the company then conducts the necessary testing to determine what amount can be classified as reserves.

To initiate the LBA process, companies wanting to acquire additional coal must file an application with the BLM's state office indicating interest in a specific coal tract. The BLM reviews the initial application to determine whether the application conforms to existing land-use plans for that particular tract of land and that the application would provide for maximum coal recovery. The application is further reviewed by a regional coal team at a public meeting. Based on a review of the available information and public comment, the regional coal team will make a recommendation to the BLM whether to continue, modify or reject the application.

If the BLM determines to continue the application, the company that submitted the application will pay for a BLM-directed environmental analysis or an environmental impact statement to be completed. This analysis or impact statement is subject to publication and public comment. The BLM may consult with other governmental agencies during this process, including state and federal agencies, surface management agencies, Native American tribes or bands, the U.S. Department of Justice or others as needed. The public comment period for an analysis or impact statement typically occurs over a 60-day period.

After the environmental analysis or environmental impact statement has been issued and a recommendation has been published that supports the lease sale of the LBA tract, the BLM schedules a public competitive lease sale. The BLM prepares an internal estimate of the fair market value of the coal that is based on its economic analysis and comparable sales analysis. Prior to the lease sale, companies interested in acquiring the lease must send sealed bids to the BLM. The bid amounts for the lease are payable in five annual installments, with the first 20% installment due when the mining operator submits its initial bid for an LBA. Before the lease is approved by the BLM, the company must first furnish to the BLM an initial rental payment for the first year of rent along with either a bond for the next 20% annual installment payment for the bid amount, or an application for history of timely payment, in which case the BLM may waive the bond requirement if the company successfully meets all the qualifications of a timely payor. The bids are opened at the lease sale. If the BLM decides to grant a lease, the lease is awarded to the company that submitted the highest total bid meeting or exceeding the BLM's fair market value estimate, which is not published. The BLM, however, is not required to grant a lease even if it determines that a bid meeting or exceeding the fair market value of the coal has been submitted. The winning bidder must also submit a report setting forth the nature and extent of its coal holdings to the U.S. Department of Justice for a 30-day antitrust review of the lease. If the successful bidder was not the initial applicant, the BLM will refund the initial applicant certain fees it paid in connection with the application process, for example the fees associated with the environmental analysis or environmental impact statement, and the winning bidder will bear those costs. Coal won through the LBA process and subject to federal leases are administered by the U.S. Department of Interior under the Federal Coal Leasing Amendment Act of 1976. In addition, we occasionally add small coal tracts adjacent to our existing LBAs through an agreed upon lease modification with the BLM. Once the BLM has issued a lease, the company must also complete the permitting process before it can mine the coal. You should see the section entitled "Environmental and Other Regulatory Matters."

Most of our federal coal leases have an initial term of 20 years and are renewable for subsequent 10-year periods and for so long thereafter as coal is produced in commercial quantities. These leases require diligent development within the first ten years of the lease award with a required coal extraction of 1.0% of the total coal under the lease by the end of that 10-year period. At the end of the 10-year development period, the lessee is required to maintain continuous operations, as defined in the applicable leasing regulations. In certain cases a lessee may combine contiguous leases into a logical mining unit, which we refer to as an LMU. This allows the production of coal from any of the leases within the LMU to be used to meet the continuous operation requirements for the entire LMU. Some of our mines are also subject to coal leases with applicable state regulatory agencies and have different terms and conditions that we must adhere to in a similar way to our federal leases. Under these federal and state leases, if the leased coal is not diligently developed during the initial 10-year development period or if certain other terms of the leases are not complied with, including the requirement to produce a minimum quantity of coal or pay a minimum production royalty, if applicable, the BLM or the applicable state regulatory agency can terminate the lease prior to the expiration of its term.

Title to Coal Property

Title to coal properties held by lessors or grantors to us and our subsidiaries and the boundaries of properties are normally verified at the time of leasing or acquisition. However, in cases involving less significant properties and consistent with industry practices, title and boundaries are not completely verified until such time as our independent operating subsidiaries prepare to mine such reserves. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine such reserves could be adversely affected. You should see "A defect in title or the loss of a leasehold interest in certain property could limit our ability to mine our coal reserves or result in significant unanticipated costs" contained under the heading "Risk Factors" for more information.

At December 31, 2012, approximately 21.3% of our coal reserves were held in fee, with the balance controlled by leases, most of which do not expire until the exhaustion of mineable and merchantable coal. Under current mining plans, substantially all reported leased reserves will be mined out within the period of existing leases or within the time period of assured lease renewals. Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross sales price of the mined coal. The majority of the significant leases are on a percentage royalty basis. In some cases, a payment is required, payable either at the time of execution of the lease or in annual installments. In most cases, the prepaid royalty amount is applied to reduce future production royalties.

From time to time, lessors or sublessors of land leased by our subsidiaries have sought to terminate such leases on the basis that such subsidiaries have failed to comply with the financial terms of the leases or that the mining and related operations conducted by such subsidiaries are not authorized by the leases. Some of these allegations relate to leases upon which we conduct operations material to our consolidated financial position, results of operations and liquidity, but we do not believe any pending claims by such lessors or sublessors have merit or will result in the termination of any material lease or sublease.

We leased approximately 41,768 acres of property to other coal operators in 2012. We received royalty income of $10.0 million in 2012 from the mining of approximately 3.1 million tons, $8.2 million in 2011 from the mining of approximately 2.9 million tons and $4.1 million in 2010 from the mining of approximately 1.8 million tons on those properties. We have included reserves at properties leased by us to other coal operators in the reserve figures set forth in this report.

ITEM 3. LEGAL PROCEEDINGS.

In addition to the following matters, we are involved in various claims and legal actions arising in the ordinary course of business, including employee injury claims. After conferring with counsel, it is the opinion of management that the ultimate resolution of these claims, to the extent not previously provided for, will not have a material adverse effect on our consolidated financial condition, results of operations or liquidity.

Permit Litigation Matters

Surface mines at our Mingo Logan and Coal-Mac mining operations were identified in an existing lawsuit brought by the Ohio Valley Environmental Coalition (OVEC) in the U.S. District Court for the Southern District of West Virginia as having been granted Clean Water Act § 404 permits by the Army Corps of Engineers ("Corps"), allegedly in violation of the Clean Water Act and the National Environmental Policy Act. The lawsuit, brought by

OVEC in September 2005, originally was filed against the Corps for permits it had issued to four subsidiaries of a company unrelated to us or our operating subsidiaries. The suit claimed that the Corps had issued permits to the subsidiaries of the unrelated company that did not comply with the National Environmental Policy Act and violated the Clean Water Act.

The court ruled on the claims associated with those four permits in orders of March 23 and June 13, 2007. In the first of those orders, the court rescinded the four permits, finding that the Corps had inadequately assessed the likely impact of valley fills on headwater streams and had relied on inadequate or unproven mitigation to offset those impacts. In the second order, the court entered a declaratory judgment that discharges of sediment from the valley fills into sediment control ponds constructed in-stream to control that sediment must themselves be permitted under a different provision of the Clean Water Act, § 402, and meet the effluent limits imposed on discharges from these ponds. Both of the district court rulings were appealed to the U.S. Court of Appeals for the Fourth Circuit.

Before the court entered its first order, the plaintiffs were permitted to amend their complaint to challenge the Coal-Mac and Mingo Logan permits. Plaintiffs sought preliminary injunctions against both operations, but later reached agreements with our operating subsidiaries that have allowed mining to progress in limited areas while the district court's rulings were on appeal. The claims against Coal-Mac were thereafter dismissed.

In February 2009, the Fourth Circuit reversed the District Court. The Fourth Circuit held that the Corps' jurisdiction under Section 404 of the Clean Water Act is limited to the narrow issue of the filling of jurisdictional waters. The court also held that the Corps' findings of no significant impact under the National Environmental Policy Act and no significant degradation under the Clean Water Act are entitled to deference. Such findings entitle the Corps to avoid preparing an environmental impact statement, the absence of which was one issue on appeal. These holdings also validated the type of mitigation projects proposed by our operations to minimize impacts and comply with the relevant statutes. Finally, the Fourth Circuit found that stream segments, together with the sediment ponds to which they connect, are unitary "waste treatment systems," not "waters of the United States," and that the Corps had not exceeded its authority in permitting them.

OVEC sought rehearing before the entire appellate court, which was denied in May 2009, and the decision was given legal effect in June 2009. An appeal to the U.S. Supreme Court was then filed in August 2009. On August 3, 2010 OVEC withdrew its appeal.

Mingo Logan filed a motion for summary judgment with the district court in July 2009, asking that judgment be entered in its favor because no outstanding legal issues remained for decision as a result of the Fourth Circuit's February 2009 decision. By a series of motions, the United States obtained extensions and stays of the obligation to respond to the motion in the wake of its letters to the Corps dated September 3 and October 16, 2009 (discussed below). By order dated April 22, 2010, the District Court stayed the case as to Mingo Logan for the shorter of either six months or the completion of the U.S. Environmental Protection Agency's (the "EPA") proposed action to deny Mingo Logan the right to use its Corps' permit (as discussed below).

On October 15, 2010, the United States moved to extend the existing stay for an additional 120 days (until February 22, 2011) while the EPA Administrator reviewed the "Recommended Determination" issued by the EPA Region 3. By Memorandum Opinion and Order dated November 2, 2010, the court granted the United States' motion. On January 13, 2011, the EPA issued its "Final Determination" to withdraw the specification of two of the three watersheds as a disposal site for dredged or fill material approved under the current Section 404 permit. The court was notified of the Final Determination and by order dated March 21, 2011 stayed further proceedings in the case until further order of the court, in light of the challenge to the EPA's "Final Determination" currently pending in federal court in Washington, DC. As described more fully below, the federal court in Washington, DC, by Memorandum and Opinion and separate Order, each dated March 23, 2012, granted Mingo Logan's motion for summary judgment, vacated EPA's Final Determination and found valid and in full force Mingo Logan's Section 404 permit. On April 5, 2012, Mingo Logan moved to lift the stay referenced above.

On June 5, 2012, the Court entered an order lifting the stay and allowing the case to proceed on Mingo Logan's Motion for Summary Judgment. Shortly thereafter, OVEC filed a motion for leave to file a seventh amended and supplemental complaint seeking to update existing counts and raising two new claims (one, to enforce EPA's "Final Determination" and, the other, that the Corps' refusal to prepare a Supplemental Environmental Impact Statement violates the APA and NEPA). By Memorandum, Opinion and Order dated July 25, 2012, the Court granted OVEC's motion and directed the Clerk to file OVEC's Seventh Amended and Supplemental Complaint.

Mingo Logan filed its Motion for Summary Judgment on August 31, 2012, along with its Answer to the Seventh Amended and Supplemental Complaint. All responses and replies to Mingo Logan's Motion have been filed and the matter is pending before the Court.

EPA Actions Related to Water Discharges from the Spruce Permit

By letter of September 3, 2009, the EPA asked the Corps of Engineers to suspend, revoke or modify the existing permit it issued in January 2007 to Mingo Logan under Section 404 of the Clean Water Act, claiming that "new information and circumstances have arisen which justify reconsideration of the permit." By letter of September 30, 2009, the Corps of Engineers advised the EPA that it would not reconsider its decision to issue the permit. By letter of October 16, 2009, the EPA advised the Corps that it has "reason to believe" that the Mingo Logan mine will have "unacceptable adverse impacts to fish and wildlife resources" and that it intends to issue a public notice of a proposed determination to restrict or prohibit discharges of fill material that already are approved by the Corps' permit. By federal register publication dated April 2, 2010, the EPA issued its "Proposed Determination to Prohibit, Restrict or Deny the Specification, or the Use for Specification of an Area as a Disposal Site: Spruce No. 1 Surface Mine, Logan County, WV" pursuant to Section 404(c) of the Clean Water Act, the EPA accepted written comments on its proposed action (sometimes known as a "veto proceeding"), through June 4, 2010 and conducted a public hearing, as well, on May 18, 2010. We submitted comments on the action during this period. On September 24, 2010, the EPA Region 3 issued a "Recommended Determination" to the EPA Administrator recommending that the EPA prohibit the placement of fill material in two of the three watersheds for which filling is approved under the current Section 404 permit. Mingo Logan, along with the Corps, West Virginia DEP and the mineral owner, engaged in a consultation with the EPA as required by the regulations, to discuss "corrective action" to address the "unacceptable adverse effects" identified. On January 13, 2011, the EPA issued its "Final Determination" pursuant to Section 404(c) of the Clean Water Act to withdraw the specification of two of the three watersheds approved in the current Section 404 permit as a disposal site for dredged or fill material. By separate action, Mingo Logan sued the EPA on April 2, 2010 in federal court in Washington, D.C. seeking a ruling that the EPA has no authority under the Clean Water Act to veto a previously issued permit (Mingo Logan Coal Company, Inc. v. USEPA, No. 1:10-cv-00541(D.D.C.)). The EPA moved to dismiss that action, and we responded to that motion.

Pursuant to a scheduling order for summary disposition of the case, motions and cross-motions for summary judgment by both parties were filed. On November 30, 2011, the court heard arguments from the parties limited only to the threshold issue of whether the EPA had the authority under Section 404(c) of the Clean Water Act to withdraw the specification of the disposal site after the Corps had already issued a permit under Section 404(a). The court deferred consideration of the remaining issue (i.e. whether the EPA's "Final Determination" is otherwise lawful) until after consideration of the threshold issue. On March 23, 2012, the court entered an Order and a Memorandum Opinion granting Mingo Logan's motion for summary judgment, denying the EPA's cross-motion for summary judgment, vacating the Final Determination and ordering that Mingo Logan's Section 404 permit remains valid and in full force.

On May 11, 2012, the EPA filed a notice of appeal to the United States Court of Appeals for the District of Columbia Circuit. The parties have fully briefed the case and the court has scheduled oral arguments for March 14, 2013.

Allegheny Energy Contract Matter

Allegheny Energy Supply ("Allegheny"), the sole customer of coal produced at our subsidiary Wolf Run Mining Company's ("Wolf Run") Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. ("Hunter Ridge"), and ICG in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claimed that Wolf Run breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 mine in the third quarter of 2006, and that Wolf Run continued to breach the contract by failing to ship in volumes referenced in the contract. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped.

After extensive searching for gas wells and rehabilitation of the mine, it was re-opened in 2007, but with notice to Allegheny that it would necessarily operate at reduced volumes in order to safely and effectively avoid the many gas wells within the reserve. The amended complaint also alleged that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005. Allegheny voluntarily dropped the breach of representation claims later. Allegheny claimed that it would incur costs in excess of $100 million to purchase replacement coal over the life of the contract. ICG, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On November 3, 2008, ICG, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and conspiracy. On September 23, 2009, Allegheny filed a second amended complaint alleging several alternative theories of liability in its effort to extend contractual liability to ICG, which was not a party to the original contract and did not exist at the time Wolf Run and Allegheny entered into the contract. No new substantive claims were asserted. ICG answered the second amended complaint on October 13, 2009, denying all of the new claims. The Company's counterclaim was dismissed on motion for summary judgment entered on May 11, 2010. Allegheny's claims against ICG were also dismissed by summary judgment, but the claims against Wolf Run and Hunter Ridge were not. The court conducted a non-jury trial of this matter beginning on January 10, 2011 and concluding on February 1, 2011.

At the trial, Allegheny presented its evidence for breach of contract and claimed that it is entitled to past and future damages in the aggregate of between $228 million and $377 million. Wolf Run and Hunter Ridge presented their defense of the claims, including evidence with respect to the existence of force majeure conditions and excuse under the contract and applicable law. Wolf Run and Hunter Ridge presented evidence that Allegheny's damages calculations were significantly inflated because it did not seek to determine damages as of the time of the breach and in some instances artificially assumed future nondelivery or did not take into account the apparent requirement to supply coal in the future. On May 2, 2011, the trial court entered a Memorandum and Verdict determining that Wolf Run had breached the coal supply contract and that the performance shortfall was not excused by force majeure. The trial court awarded total damages and interest in the amount of $104.1 million. ICG and Allegheny filed post-verdict motions in the trial court and on August 23, 2011, the court denied the parties' motions. The court entered a final judgment on August 25, 2011, in the amount of $104.1 million, which included pre-judgment interest. The parties appealed the lower court's decision to the Superior Court of Pennsylvania. On August 13, 2012, the Superior Court of Pennsylvania ruled that the lower court should have calculated damages as of the date of breach, and remanded the matter back to the lower court with instructions to recalculate the award. On November 19, 2012, Allegheny filed a Petition for Allowance of Appeal with the Supreme Court of Pennsylvania and Wolf Run and Hunter Ridge filed an Answer. This Petition is pending.

ICG Hazard

The Sierra Club, on December 3, 2010, filed a Notice of Intent ("NOI") to sue ICG Hazard, LLC ("Hazard"), alleging violations of the Clean Water Act and the Surface Mining Control and Reclamation Act of 1977 at

Hazard's Thunder Ridge surface mine. The NOI, which was supplemented by a revised filing on February 24, 2011, claims that Hazard is discharging selenium and contributing to conductivity levels in the receiving streams in violation of state and federal regulations. On May 24, 2011, the Sierra Club sued Hazard in U.S. District Court for the Eastern District of Kentucky under the Citizens Suit provisions of the Clean Water Act and the Surface Mining Control and Reclamation Act seeking civil penalties, injunctive relief and attorneys' fees. On February 17, 2012, ICG Hazard filed a motion for summary judgment. Also on February 17, 2012, the Sierra Club filed a competing motion for summary judgment.

On September 28, 2012, the court entered a Memorandum Opinion and Order granting Hazard summary judgment on both Clean Water Act ("CWA") and Surface Mining Control and Reclamation Act ("SMCRA") claims finding that the CWA permit "shield" applies and that the SMCRA cannot be used to circumvent the CWA permit shield with respect to "point source" discharges. The court denied summary judgment to the extent the facts showed there were "non-point source" discharges from areas disturbed by surface mining activities. On October 4, 2012, the Sierra Club filed a Motion to Clarify Claims and Request Final Judgment Order notifying the court that all of its claims in the matter involved discharges from discrete "point sources" and that there remain no issues of law or fact that require court resolution. The court entered a final judgment on January 11, 2013. On January 22, 2013, the Sierra Club filed a notice of appeal to the United States Court of Appeals for the Sixth Circuit.

Patriot Coal Corporation Bankruptcy

On December 31, 2005, Arch entered into a purchase and sale agreement with Magnum Coal Company ("Magnum") to sell certain assets to Magnum. On July 23, 2008, Patriot Coal Corporation acquired Magnum. On July 9, 2012, Patriot Coal Corporation and certain of its wholly owned subsidiaries, including Magnum (collectively, "Patriot"), filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York.

On September 20, 2012, Patriot filed a motion with the U.S. Bankruptcy Court for the Southern District of New York to reject a master coal sales agreement entered into on December 31, 2005 between us and Magnum, which was established in order to meet obligations under a coal sales agreement with a customer who did not consent to the assignment of their contract to Magnum. On December 18, 2012, the court accepted Patriot's motion to reject the master coal sales agreement. As a result of the court's decision, Arch has accrued $58.3 million, which represents the discounted value of the remaining monthly buyout amounts under the underlying coal sales agreement.

ITEM 4. MINE SAFETY DISCLOSURES

The statement concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95 to this Annual Report on Form 10-K for the period ended December 31, 2012.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market for Registrant's Common Equity and Related Stockholder Matters

Our common stock is listed and traded on the New York Stock Exchange under the symbol "ACI". On February 15, 2013, our common stock closed at $5.92 on the New York Stock Exchange. On that date, there were approximately 6,300 holders of record of our common stock.

Holders of our common stock are entitled to receive dividends when they are declared by our board of directors. When dividends are declared on common stock, they are usually paid in mid-March, June, September and December. We paid dividends on our common stock totaling $42 million, or $0.20 per share, in 2012 and $80.7 million, or $0.43 per share, in 2011. There is no assurance as to the amount or payment of dividends in the future because they are dependent on our future earnings, capital requirements, financial condition, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors. You should see Note 2, Debt and Financing Arrangements, beginning on Page F-15 for more information about restrictions on our ability to declare dividends.

The following table sets forth for each period indicated the dividends paid per common share, the high and low sale prices of our common stock for each of the quarterly periods indicated.

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends per common share	$ 0.11	$ 0.03	$ 0.03	$ 0.03
High	15.99	11.06	8.05	8.86
Low	10.44	5.41	5.16	6.15

	2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends per common share	$ 0.10	$ 0.11	$ 0.11	$ 0.11
High	36.99	36.75	28.76	20.37
Low	30.70	24.10	14.28	13.09

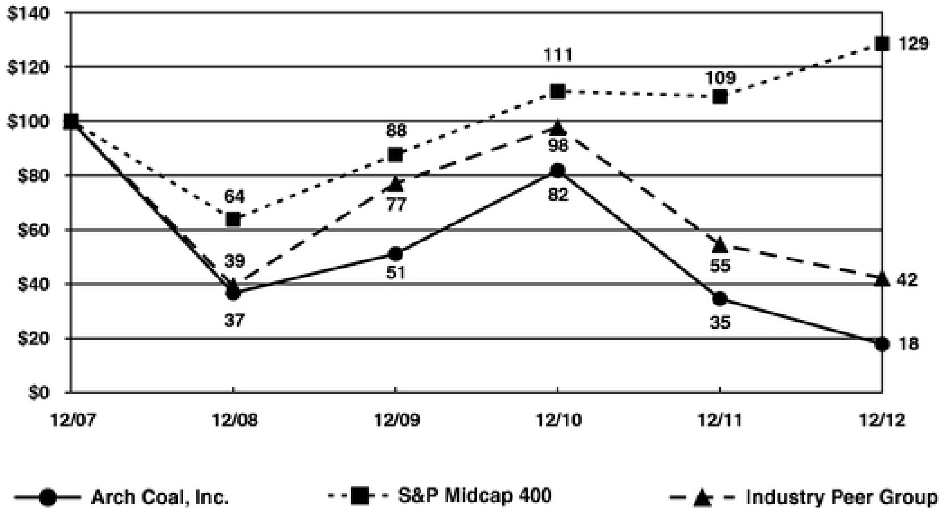
Stock Price Performance Graph

The following performance graph compares the cumulative total return to stockholders on our common stock with the cumulative total return on two indices: a peer group, consisting of CONSOL Energy, Inc., Alpha Natural Resources, Inc. and Peabody Energy Corp., and the Standard & Poor's (S&P) 400 (Midcap) Index. The graph assumes that:

- you invested $100 in Arch Coal common stock and in each index at the closing price on December 31, 2007;
- all dividends were reinvested;
- annual reweighting of the peer groups; and
- you continued to hold your investment through December 31, 2012.

You are cautioned against drawing any conclusions from the data contained in this graph, as past results are not necessarily indicative of future performance. The indices used are included for comparative purposes only and do not indicate an opinion of management that such indices are necessarily an appropriate measure of the relative performance of our common stock.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Arch Coal, Inc., the S&P Midcap 400 Index
and an Industry Peer Group



* $100 invested on 12/31/07 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/07	12/08	12/09	12/10	12/11	12/12
Arch Coal, Inc.	100.00	36.62	51.07	81.82	34.53	17.81
S&P Midcap 400	100.00	63.77	87.61	110.94	109.02	128.51
Industry Peer Group	100.00	39.23	77.08	97.67	54.53	42.19

Issuer Purchases of Equity Securities

In September 2006, our board of directors authorized a share repurchase program for the purchase of up to 14,000,000 shares of our common stock. There is no expiration date on the current authorization, and we have not made any decisions to suspend or cancel purchases under the program. We did not purchase any shares of our common stock under this program during the fiscal year ended December 31, 2012. As of December 31, 2012, we have purchased 3,074,200 shares of our common stock under this program since the board of directors authorized the program. Based on the closing price of our common stock as reported on the New York Stock Exchange on February 15, 2013, there is approximately $64.7 million of our common stock that may yet be purchased under this program.

ITEM 6. SELECTED FINANCIAL DATA.

(In thousands, except per share data)	Year Ended December 31 2012[1]	2011[2]	2010[3][4]	2009[5]	2008
Statement of Operations Data:					
Revenues	$ 4,159,038	$ 4,285,895	$ 3,186,268	$ 2,576,081	$ 2,983,806
Change in fair value of coal derivatives and trading activities, gains (losses) net	16,590	2,907	(8,924)	12,056	55,093
Mine closure and asset impairment costs	523,568	7,316	—	—	—
Goodwill and other intangible asset impairment	346,423	—	—	—	—
Contract settlement resulting from Patriot Coal bankruptcy	58,335				
Acquisition and transition costs	—	47,360	—	13,726	—
Income (loss) from operations	(681,588)	413,576	323,984	123,714	461,270
Non-operating expenses	23,668	51,448	6,776	—	—
Net income (loss) attributable to Arch Coal	(683,955)	141,683	158,857	42,169	354,330
Basic earnings per common share	$ (3.24)	$ 0.75	$ 0.98	$ 0.28	$ 2.47
Diluted earnings per common share	$ (3.24)	$ 0.74	$ 0.97	$ 0.28	$ 2.45
Balance Sheet Data:					
Total assets	$ 10,006,777	$ 10,213,959	$ 4,880,769	$ 4,840,596	$ 3,978,964
Working capital	1,337,035	162,106	207,568	55,055	46,631
Long-term debt, less current maturities	5,085,879	3,762,297	1,538,744	1,540,223	1,098,948
Other long-term obligations	825,080	864,667	566,728	544,578	482,651
Noncurrent deferred income tax liability	664,182	976,753	—	—	—
Arch Coal stockholders' equity	2,854,567	3,578,040	2,237,507	2,115,106	1,728,733
Common Stock Data:					
Dividends per share	$ 0.20	$ 0.43	$ 0.39	$ 0.36	$ 0.34
Shares outstanding at year-end	212,247	211,671	162,605	162,441	142,833
Cash Flow Data:					
Cash provided by operating activities	$ 332,804	$ 642,242	$ 697,147	$ 382,980	$ 679,137
Depreciation, depletion and amortization, including amortization of acquired sales contracts, net	500,319	444,518	400,672	321,231	292,848
Capital expenditures	395,225	540,936	314,657	323,150	497,347
Acquisitions of businesses, net of cash acquired	—	2,894,339	—	768,819	—
Net proceeds from the issuance of long term debt	1,942,685	1,906,306	500,000	570,322	—
Net proceeds from the sale of common stock	—	1,267,933	—	326,452	—
Payments to retire debt, including redemption premium	452,934	605,178	505,627	—	—
Net increase (decrease) in borrowings under lines of credit and commercial paper program	(481,300)	424,396	(196,549)	(85,815)	13,493
Dividend payments	42,440	80,748	63,373	54,969	48,847
Operating Data:					
Tons sold	140,820	156,897	162,763	126,116	139,595
Tons produced	135,934	151,829	156,282	119,568	133,107
Tons purchased from third parties	4,327	5,557	6,825	7,477	6,037

(1) Our results in 2012 were impacted by challenging market conditions. In response to these conditions, we idled 10 mines in Appalachia and curtailed production at other thermal mines. We incurred $523.6 million of closure and impairment costs relating to the closures, and recognized goodwill and other intangible asset impairment charges $346.4 million. In addition, we refinanced our debt, increasing our average borrowing level to build cash and highly liquid investments on the balance sheet as well as to decrease near-term maturities of debt. See further description of these transactions in the "Overview" in Item 7. Management's Discussion and Analysis.

(2) On June 15, 2011, we completed our acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. To finance the acquisition, we sold 48.7 million shares of our common stock and issued $2.0 billion in aggregate principal amount of senior unsecured notes. We directly expensed costs related to the financing and acquisition of $104.2 million.

(3) In the second quarter of 2010, we exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest in Knight Hawk Holdings, LLC (Knight Hawk), increasing our ownership to 42%. We recognized a pre-tax gain of $41.6 million on the transaction, representing the difference between the fair value and net book value of the coal reserves, adjusted for our retained ownership interest in the reserves through the investment in Knight Hawk.

(4) On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 at par. We used the net proceeds from the offering and cash on hand to fund the redemption on September 8, 2010 of $500.0 million aggregate principal amount of our outstanding 6.75% senior notes due in 2013 at a redemption price of 101.125%. We recognized a loss on the redemption of $6.8 million.

(5) On October 1, 2009, we purchased the Jacobs Ranch mining complex in the Powder River Basin from Rio Tinto Energy America for a purchase price of $768.8 million. To finance the acquisition, we sold 19.55 million shares of our common stock and $600.0 million in aggregate principal amount of senior unsecured notes. The net proceeds received from the issuance of common stock were $326.5 million and the net proceeds received from the issuance of the 8.75% senior unsecured notes were $570.3 million.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Overview

Challenging coal markets significantly impacted our results in 2012. Global benchmark metallurgical prices declined 50% since their peak in mid-2011, while U.S. thermal coal consumption declined to levels not seen since the mid-1990s.

Driving the weakness in the domestic demand for thermal coal during 2012 was reduced coal-fired generation resulting from an unseasonably warm 2011/2012 winter coupled with low natural gas prices, which resulted in the substitution of natural gas for coal by power generators. As a result, coal stockpiles at generators remain at higher than normal levels, though levels declined during the second half of 2012. A rise in natural gas prices relative to the last year should increase output at coal-fueled power plants.

Thermal coal exports somewhat offset the weakness in domestic markets in 2012. We exported 13.6 million tons of both thermal and metallurgical coal in 2012, shipping into Europe and South America, as well as new markets in the Middle East and Asia. We expect continued strength in the seaborne coal markets in 2013, though perhaps not at 2012 levels. Colder winter temperatures in major coal-burning regions of Asia, as well as coal's competitive advantage versus other power generation fuels in Europe, should help support U.S. coal exports in 2013.

Metallurgical coal demand has been affected by weakening in the global steel mill capacity utilization, due to slowing economic growth. Constraints resulting from the recession in Europe and slower-than-expected growth in China affected consumer demand and reduced steel production and raw material consumption in 2012. We expect infrastructure spending in China and Brazil and stimulus spending in developed economies, when combined with global production curtailments, to benefit metallurgical markets in the future.

In response to these market conditions, we, along with many other domestic producers, curtailed production and took steps to control costs in a reduced-volume environment. In the Powder River Basin, up to three draglines and related support equipment have been idled at various times during 2012. We redeployed other idle assets by performing reclamation activities. We limited railcar loadings at the Black Thunder mine and we reduced labor costs through scheduling changes and attrition.

In Appalachia, we closed or idled ten higher-cost operations and curtailed production at other mines. We have controlled costs by eliminating discretionary spending, reducing headcount, consolidating operations and managing maintenance costs.

In the Western Bituminous region, we reduced cash costs by reducing headcount and shifting volumes to lower cost mines. We idled the longwall at our Dugout Canyon mine in the fourth quarter.

While controlling capital spending at thermal coal mines, we have proceeded with metallurgical coal development projects, namely the Leer mine, and the expansion of our coal exporting network.

These efforts will help position us for expected market recovery in the metallurgical and thermal export markets. Due to the uncertain timing of such recovery, we undertook financing transactions to maintain a strong liquidity position. During 2012, we increased our cash on hand by $646 million, invested $237 million in highly liquid investments and decreased our short-term borrowings by $248 million. At the end of 2012, we had cash and short-term investments of just over $1.0 billion, and no borrowings under our credit facilities. Our available liquidity totaled $1.4 billion at December 31, 2012. See discussion in "Liquidity" for the details of our financing transactions.

Items Affecting Comparability of Reported Results

Acquisition of ICG—On June 15, 2011, we completed our acquisition of ICG, a leading coal producer, adding 12 mining complexes in Appalachia, one complex in the Illinois Basin and one mine under development in Appalachia, along with other coal reserves not currently in development. To finance the acquisition, we received net proceeds of $1.3 billion from the sale of our common stock and issued $2.0 billion in aggregate principal amount of senior unsecured notes. We directly expensed costs related to the financing and acquisition of $104.2 million.

Mine closures—As mentioned in the "Overview", in response to decreasing demand for thermal coal, we made the decision to close or idle 10 mining complexes during 2012. We incurred costs relating to these closures and idlings of approximately $524 million. See further discussion of the impacts of these closures in "Results of Operations".

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Summary. Our results during 2012 when compared to 2011 were impacted substantially by weak market conditions which led us to rationalize supply through mine closures, idlings and production curtailments.

Revenues. Our revenues consist of coal sales and revenues from our ADDCAR subsidiary acquired with ICG.

The following table summarizes information about coal sales during the year ended December 31, 2012 and compares it with the information for the year ended December 31, 2011:

	Year Ended December 31,		Increase (Decrease)	
	2012	2011	Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Coal sales	$ 4,138,882	$ 4,280,605	$ (141,723)	(3.3)%
Tons sold	140,820	156,897	(16,077)	(10.2)%
Coal sales realization per ton sold	$ 29.39	$ 27.28	$ 2.11	7.7%

Coal sales decreased 3% in 2012 from 2011, as we reduced production and closed mines in response to the weak market conditions. The impact of lower volumes was partially offset by higher coal sales realizations per ton, as increased export activity resulted in higher selling prices. Transportation and other delivery costs also increased, however, as discussed in "Cost of Coal Sales". We have provided more information about the tons sold and the coal sales realizations per ton by operating segment under the heading "Operating segment results".

Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the year ended December 31, 2012 and compares it with the information for the year ended December 31, 2011:

	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase (Decrease) in Net Income Amount
	(Amounts in thousands, except percentages)		
Cost of sales	$ 3,438,013	$ 3,267,910	$ (170,103)
Depreciation, depletion and amortization	525,508	466,587	(58,921)
Amortization of acquired sales contracts, net	(25,189)	(22,069)	3,120
Change in fair value of coal derivatives and coal trading activities, net	(16,590)	(2,907)	13,683
Coal derivative settlements, non-hedging	(43,990)	7	43,997
Selling, general and administrative expenses	134,299	119,056	(15,243)
Contract settlement resulting from Patriot Coal bankruptcy	58,335	—	(58,335)
Legal contingencies	(79,532)	—	79,532
Mine closure and asset impairment costs	523,568	7,316	(516,252)
Goodwill and other intangible asset impairment	346,423	—	(346,423)
Acquisition and transition costs	—	47,360	47,360
Other operating income, net	(20,219)	(10,941)	9,278
Total costs, expenses and other	$ 4,840,626	$ 3,872,319	$ (968,307)

Cost of coal sales. Our cost of sales increased in 2012 from 2011 primarily from the impact of the acquisition of the ICG operations and an increase in transportation costs as a result of the increase in export shipments. These factors were partially offset by the impact of lower thermal coal demand in all operating segments which resulted in our decision to close or idle mining operations and curtail production. We have provided more information about the performance and profitability of our operating segments under the heading "Operating segment results".

Depreciation, depletion and amortization. When compared with 2011, higher depreciation, depletion and amortization costs in 2012 resulted primarily from the acquired ICG operations, partially offset by the impact of lower depreciation and amortization on assets amortized or depleted on the basis of tons produced, processed, or sold.

Amortization of acquired sales contracts, net. The fair values of acquired sales contracts are amortized over the tons of coal shipped during the term of the contracts. In 2011, amortization income of $41.5 million related to the contracts we acquired with the ICG operations was higher than what we recognized in 2012 due to the amortization of contracts whose term ended in 2011. Offsetting the amortization of the ICG contracts in 2011 was expense of $19.5 million related to contracts acquired with the Jacobs Ranch operations in the Powder River Basin in 2009.

Change in fair value of coal derivatives and coal trading activities, net. The gains reflected in 2012 relate primarily to positions in the API-2 market, the derivatives market for coal delivered into Europe. We entered into these positions to manage price risk on physical export sales into Europe. These positions are not accounted for as hedges, so the change in the positions' fair value prior to settlement is reflected in this line on the consolidated statement of operations, and then reclassified when the positions settle.

Coal derivative settlements, non-hedging. The gains in 2012 reflect settlements at the termination date of the API-2 positions described above.

Selling, general and administrative expenses. Selling, general and administrative expenses in 2012 increased when compared with 2011 primarily due to an increase in employee compensation costs and an increase in fees for professional and legal services of approximately $5.0 million. Costs increased due to the ICG acquisition in 2011, the staffing of our sales offices in Singapore and London, higher sales and marketing headcount to handle increased export activity, and an increase in costs under our long-term incentive plan in 2012. Additionally, the impact in 2011 of a decrease in our deferred compensation liability in 2011 due to the drop in our stock price caused selling general and administrative expenses to increase in 2012, when compared with 2011. These costs were in part offset by a decrease in annual management incentive compensation.

Contract settlement resulting from Patriot Coal bankruptcy. In the fourth quarter of 2012, Patriot Coal's rejection of their supply agreement with us was approved by the bankruptcy court. We then agreed to a settlement of a contract that had been supplied by Patriot Coal. We will make annual payments through 2017 under this obligation.

Legal contingencies. As a result of an appellate court ruling in a lawsuit against former ICG subsidiaries, we changed our estimate of the probable loss related to the lawsuit. The suit is discussed in detail in Note 23 to the consolidated financial statements included in this Form 10-K.

Mine closure and asset impairment costs and goodwill impairment. The following costs related to closed operations, primarily in Appalachia, for the year ended December 31, 2012 :

	In millions
Parts and supplies inventory writedown	$ 2.6
Impairment of property, plant and equipment	95.6
Impairment of coal properties and deferred development costs	403.3
Royalty obligations	11.5
Employee termination benefits	12.3
Pension, postretirement and occupational disease curtailment gain, net (see notes 17 and 18)	(1.8)
	$ 523.5

Goodwill Impairment. We recognized an impairment charge of $115.8 million, the entire balance of goodwill allocated to our Black Thunder mining complex, during the second quarter of 2012 due to expectations of lower thermal coal demand and its impact on near-term sales volumes and pricing. In the fourth quarter of 2012, we recorded an impairment charge of $214.9 million representing the goodwill related to two of four operating units that were allocated goodwill in the acquisition of ICG. See further discussion in "Critical Accounting Policies".

Other operating income, net. When compared with the year ended December 31, 2011, the increase in other operating income, net for the year ended December 31, 2012 was primarily the result of an increase in net commercial-related income of $7.7 million and gains on the sale of non-core assets of $10.3 million. These were partially offset by unrealized mark to market losses of $13.8 million on our diesel fuel risk management program. Because we do not apply hedge accounting to these positions, accounting rules do not allow the gains and losses from these activities to be recorded with the underlying purchases in the statement of operations as if they qualified for hedge accounting.

Operating segment results. The following table shows results by operating segment for the year ended December 31, 2012 and compares it with the information for the year ended December 31, 2011:

	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase (Decrease) $	Increase (Decrease) %
Powder River Basin				
Tons sold (in thousands)	104,394	117,846	(13,452)	(11.4)%
Coal sales realization per ton sold(1)	$ 13.61	$ 13.62	$ (0.01)	(0.1)%
Cost per ton sold	$ 12.77	$ 12.11	$ 0.66	5.5%
Operating margin per ton sold(2)	$ 0.84	$ 1.51	$ (0.67)	(44.4)%
Adjusted EBITDA(3) (in thousands)	$ 265,231	$ 370,423	$ (105,192)	(28.4)%
Appalachia				
Tons sold (in thousands)	18,717	20,874	(2,157)	(10.3)%
Coal sales realization per ton sold(1)	$ 85.42	$ 84.52	$ 0.90	1.1%
Cost per ton sold	$ 83.17	$ 70.88	$ 12.29	17.3%
Operating margin per ton sold(2)	$ 2.25	$ 13.64	$ (11.39)	(83.5)%
Adjusted EBITDA(3) (in thousands)	$ 395,806	$ 468,806	$ (73,000)	(15.6)%
Western Bituminous				
Tons sold (in thousands)	15,586	17,041	(1,455)	(8.5)%
Coal sales realization per ton sold(1)	$ 35.67	$ 35.72	$ (0.05)	(0.1)%
Cost per ton sold	$ 26.80	$ 28.77	$ (1.97)	(6.8)%
Operating margin per ton sold(2)	$ 8.87	$ 6.95	$ 1.92	27.6%
Adjusted EBITDA(3) (in thousands)	$ 216,246	$ 200,900	$ 15,346	7.6%

(1) These per-ton measurements reflect adjustments to numbers reported under U.S. GAAP to reflect the complete results we achieved within our operating segments. Since other companies may calculate these per ton amounts differently, our calculation may not be comparable to similarly titled measures used by those companies.

	Year Ended December 31, 2012	Year Ended December 31, 2011
Transportation costs netted against per-ton realizations to reflect netback price to the region		
Powder River Basin	$ 1.00	$ 0.36
Appalachia	$ 9.82	$ 6.73
Western Bituminous	$ 12.54	$ 3.76
API-2 risk management position settlements included in per-ton realizations not classified as coal sales revenues in statement of operations		
Appalachia	$ 0.78	—
Western Bituminous	$ 1.50	—
Diesel risk management position settlements not classified as cost of coal sales in statement of operations		
Powder River Basin	$ 0.09	—
Appalachia	$ 0.10	—

(2) Operating margin per ton sold is calculated as coal sales revenues less cost of coal sales, depreciation, depletion and amortization and sales contract amortization divided by tons sold.

(3) Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. Segment Adjusted EBITDA is reconciled to net income at the end of this "Results of Operations" section.

Powder River Basin—Segment Adjusted EBITDA decreased in 2012 when compared to 2011, due to the lower sales volumes in the Powder River Basin from the production curtailments in response to market conditions. Per-ton margins were also lower due to the higher per-unit cash costs, resulting from the lower production levels.

Appalachia—Operating margins decreased in 2012 when compared with 2011 due to the impacts of lower production levels as a result of mine closures and other production rationalization, including an extended longwall move at the Mountain Laurel complex. The extended longwall move at the Mountain Laurel complex reflected our move to a new seam. The new seam is thinner than the previous seam, resulting in a loss of yield at the mine, translating into slightly higher costs; however, we anticipate more consistent quality in the new seam. We sold 7.5 million tons of metallurgical-quality coal in 2012 compared to 7.4 million tons in 2011.

Reduced operating margins were offset by a benefit in Adjusted EBITDA of the $79.5 million decrease in a legal contingency liability acquired with ICG. Mine closure and asset impairment costs are excluded from the per-ton costs and operating margins above, though the ongoing maintenance costs of those operations is included.

Western Bituminous—Segment Adjusted EBITDA increased from 2011 due to lower production costs stemming from improved cost control, higher sales volumes from lower-cost mines in the region and reductions to accruals for sales-sensitive costs.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2012 and compares it with the information for the year ended December 31, 2011:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2012	2011	$	%
	(Amounts in thousands, except percentages)			
Interest expense	$ (317,626)	$ (230,186)	$ (87,440)	(38.0)%
Interest income	5,478	3,309	2,169	65.5%
	$ (312,148)	$ (226,877)	$ (85,271)	(37.6)%

The increase in interest expense is due to an increase in our outstanding debt in 2012 when compared with 2011, as a result of the financing transactions discussed in "Liquidity".

Other nonoperating expense. Amounts reported as nonoperating consist of expenses resulting from financing activities, other than interest costs. During 2012, nonoperating expense consists primarily of the write-off of financing fees relating to decreases in our revolving credit facility capacity. During 2011, nonoperating expense represents financing related costs of the ICG acquisition, including the cost to maintain a bridge financing facility, which was not utilized.

	Year Ended December 31		Increase (Decrease) In Net Income
	2012	2011	$
	(In thousands)		
Net loss resulting from early retirement and refinancing of debt	$ (23,668)	$ (1,958)	$ (21,710)
Bridge financing costs related to ICG	—	(49,490)	49,490
	$ (23,668)	$ (51,448)	$ 27,780

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion. The income tax benefit in 2012 reflects our pretax loss combined with percentage depletion deductions, offset by a $56.9 million non-deductible goodwill adjustment and $31.8 million to increase our valuation allowance against state tax carryforwards.

	Year Ended December 31 2012	2011	Increase In Net Income $
	(In thousands)		
Benefit from income taxes	(333,717)	(7,589)	326,128

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Summary. Our results during 2011 when compared to 2010 were impacted positively by the contribution from the acquired ICG operations on June 15, 2011 and higher average sales realizations as a result of improved market conditions, but these factors were offset by the acquisition, transition and financing costs necessary to complete the acquisition, as well as the impact of lower volumes from our Mountain Laurel complex and the Powder River Basin.

Revenues. Our revenues consist of coal sales and revenues from our ADDCAR subsidiary acquired with ICG. The following table summarizes information about coal sales during the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31, 2011	2010	Increase (Decrease) Amount	%
	(Amounts in thousands, except per ton data and percentages)			
Coal sales	$ 4,280,605	$ 3,186,268	$ 1,094,337	34.3%
Tons sold	156,897	162,763	(5,866)	(3.6)%
Coal sales realization per ton sold	$ 27.28	$ 19.58	$ 7.70	39.3%

Coal sales increased in 2011 from 2010, due to an increase in the overall average price per ton sold, the result of improved pricing on metallurgical-quality coal sold, the contribution from the ICG operations, including higher-priced metallurgical coal sales volumes, and higher steam pricing in all regions, as well as the impact of changes in regional mix on our average coal sales realization. Coal sales revenues attributed to acquired ICG operations were $601.6 million in 2011. Overall sales volumes decreased as lower sales volumes in the Powder River Basin offset the increases in the Appalachia and Western Bituminous regions. We have provided more information about the tons sold and the coal sales realizations per ton by operating segment under the heading "Operating segment results".

Costs, expenses and other. The following table summarizes costs, expenses and other components of operating income for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31, 2011	2010	Increase (Decrease) in Net Income Amount
	(Amounts in thousands, except percentages)		
Cost of sales	$ 3,267,910	$ 2,395,812	$ (872,098)
Depreciation, depletion and amortization	466,587	365,066	(101,521)
Amortization of acquired sales contracts, net	(22,069)	35,606	57,675
Change in fair value of coal derivatives and coal trading activities, net	(2,907)	8,924	11,831
Coal derivative settlements, non-hedging	7	(4,542)	(4,549)
Selling, general and administrative expenses	119,056	118,177	(879)
Mine closure and asset impairment costs	7,316	—	(7,316)
Acquisition and transition costs	47,360	—	(47,360)
Gain on Knight Hawk transaction	—	(41,577)	(41,577)
Other operating income, net	(10,941)	(15,182)	(4,241)
	$ 3,872,319	$ 2,862,284	$ (1,010,035)

Cost of coal sales. Our cost of sales increased in 2011 from 2010 primarily from the impact of the acquisition of the ICG operations, an increase in transportation costs as a result of the increase in export shipments, and an increase in sales-sensitive costs. We have provided more information about the performance and profitability of our operating segments under the heading "Operating segment results".

Depreciation, depletion and amortization. When compared with 2010, higher depreciation, depletion and amortization costs in 2011 resulted primarily from the acquired ICG operations, partially offset by the impact of lower depreciation and amortization on assets amortized or depleted on the basis of tons produced.

Amortization of acquired sales contracts, net. The fair values of acquired sales contracts are amortized over the tons of coal shipped during the term of the contracts. In 2011, amortization expense related to contracts we acquired in 2009 with the Jacobs Ranch operations in the Powder River Basin was offset by amortization income related to the contracts we acquired with the ICG operations.

Selling, general and administrative expenses. Selling, general and administrative expenses were essentially flat over 2010. Our growth in 2011 resulted in an increase in salaries, travel costs, and other professional service fees, and permitting, reserve acquisitions and environmental compliance resulted in higher legal costs. These were offset by a decrease in the net obligation under the deferred compensation plan of $7.7 million and a decrease in costs related to incentive compensation plans of $2.2 million. Amounts recognized under our deferred compensation plan are impacted by changes in the value of our common stock and changes in the value of the underlying investments. In addition, in 2010 we recognized the cost of a contribution to the Arch Coal Foundation of $5.0 million. We made no contributions in 2011.

Change in fair value of coal derivatives and coal trading activities, net. Net (gains) losses relate to the net impact of our coal trading activities and the change in fair value of other coal derivatives that have not been designated as hedge instruments in a hedging relationship. In 2011, we entered into economic hedging strategies relating to export sales that did not qualify for hedge accounting treatment, resulting in unrealized gains of approximately $12 million.

Gain on Knight Hawk Transaction. The gain was recognized on our 2010 exchange of Illinois Basin reserves for an additional ownership interest in Knight Hawk, an equity method investee operating in the Illinois Basin.

Other operating income, net. When compared with 2010, other operating income, net decreased in 2011 due to an increase in commercial-related expenses and unrealized losses on heating oil contracts entered into as economic hedges of fuel surcharges on freight agreements of $2.9 million, partially offset by approximately $9.5 million of other income generated by acquired ICG operations, primarily royalties and ash disposal income.

Operating segment results. The following table shows results by operating segment for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31, 2011	Year Ended December 31, 2010	Increase (Decrease) $	Increase (Decrease) %
Powder River Basin				
Tons sold (in thousands)	117,846	132,350	(14,504)	(11.0)%
Coal sales realization per ton sold(1)	$ 13.62	$ 12.06	$ 1.56	12.9%
Cost of sales per ton sold	$ 12.11	$ 10.97	$ 1.14	10.4%
Operating margin per ton sold(2)	$ 1.51	$ 1.09	$ 0.42	38.5%
Adjusted EBITDA(3) (in thousands)	$ 370,423	$ 366,375	$ 4,048	1.1%
Appalachia				
Tons sold (in thousands)	20,874	14,102	6,772	48.0%
Coal sales realization per ton sold(1)	$ 84.52	$ 68.93	$ 15.59	22.6%
Cost of sales per ton sold	$ 70.88	$ 55.68	$ 15.20	27.3%
Operating margin per ton sold(2)	$ 13.64	$ 13.25	$ 0.39	2.9%
Adjusted EBITDA(3) (in thousands)	$ 468,806	$ 283,787	$ 185,019	65.2%
Western Bituminous				
Tons sold (in thousands)	17,041	16,311	730	4.5%
Coal sales realization per ton sold(1)	$ 35.72	$ 32.76	$ 2.96	9.0%
Cost of sales per ton sold	$ 28.77	$ 29.44	$ (0.67)	(2.3)%
Operating margin per ton sold(2)	$ 6.95	$ 3.32	$ 3.63	109.3%
Adjusted EBITDA(3) (in thousands)	$ 200,900	$ 138,579	$ 62,321	45.0%

(1) These per-ton coal sales realizations reflect adjustments to exclude or include certain amounts to better represent the results we achieved within our operating segments. Since other companies may calculate these per ton amounts differently, our calculation may not be comparable to similarly titled measures used by those companies.

	Year Ended December 31, 2011	Year Ended December 31, 2010
Transportation costs netted against per-ton realizations to reflect netback price to the region		
Powder River Basin	$ 0.36	$ 0.08
Appalachia	$ 6.73	$ 4.99
Western Bituminous	$ 3.76	$ 0.19

(2) Operating margin per ton sold is calculated as coal sales revenues less cost of coal sales, depreciation, depletion and amortization and sales contract amortization divided by tons sold.

(3) Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. Segment Adjusted EBITDA is reconciled to net income at the end of this "Results of Operations" section.

Powder River Basin—Segment Adjusted EBITDA increased in 2011 when compared to 2010, due to higher average sales prices, reflecting the improved coal markets. Partially offsetting the impact of higher selling prices were lower sales volumes in the Powder River Basin in 2011 when compared with 2010, due to the flooding in the Midwest and a market-driven approach to sales commitments earlier in the year, as well as higher per-ton production costs. Higher production costs reflected an increase in labor, maintenance and diesel costs and an increase in sales-sensitive costs, due to the increased realizations. Per-ton costs were also higher due to the lower production levels.

Appalachia—Segment Adjusted EBITDA increased from 2010 primarily from an increase in the volumes and pricing of metallurgical-quality coal sold and the acquisition of ICG. Geology issues at the Mountain Laurel mine partially offset the volume contributions from the acquired ICG operations. We sold 7.5 million tons of metallurgical-quality coal in 2011 compared to 5.5 million tons in 2010. The benefit from higher per-ton realizations in 2011, net of sales sensitive costs, drove the improvement in our operating margins over 2010, partially offset by the impacts of the Mountain Laurel geology issues, and an increase in production at higher cost mines on our average per-ton production costs.

Western Bituminous—Improved Segment Adjusted EBITDA reflects higher sales volumes and improved pricing resulting from increased export shipments for coal from our Colorado operations. Effective cost control in the region and slightly higher production levels reduced our per-ton operating costs, which also contributed to the improved results in 2011, when compared with 2010, when two outages affected production at the Dugout Canyon mine.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase (Decrease) in Net Income	
	2011	2010	$	%
	(Amounts in thousands, except percentages)			
Interest expense	$ (230,186)	$ (142,549)	$ (87,637)	(61.5)%
Interest income	3,309	2,449	860	35.1%
	$ (226,877)	$ (140,100)	$ (86,777)	(61.9)%

The increase in interest expense during 2011 when compared with 2010 is the result of the ICG acquisition financing. See further discussion of the related transactions in "Liquidity and Capital Resources."

Other non-operating expense. The following table summarizes other non-operating expense for year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase (Decrease) In Net Income
	2011	2010	$
	(In thousands)		
Net loss resulting from early retirement and refinancing of debt	$ (1,958)	$ (6,776)	$ 4,818
Bridge financing costs related to ICG	(49,490)	—	(49,490)
	$ (51,448)	$ (6,776)	$ (44,672)

Amounts reported as non-operating consist of income or expense resulting from our financing activities, other than interest costs. Other non-operating expenses during 2011 represent financing-related costs of the ICG acquisition, including the cost to maintain a bridge financing facility, which was not used. The loss in 2010 relates to the redemption of $500 million in principal amount of the 6.75% senior notes, including the payment of the $5.6 million redemption premium, the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium on the 6.75% senior notes.

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion. The following table summarizes our income taxes for the year ended December 31, 2011 and compares it with the information for the year ended December 31, 2010:

	Year Ended December 31		Increase In Net Income
	2011	2010	$
	(In thousands)		
Provision for (benefit from) income taxes	(7,589)	17,714	25,303

The income tax provision in 2010 includes a tax benefit of $4.0 million related to the recognition of tax benefits based on settlements with taxing authorities.

Reconciliation of Segment Adjusted EBITDA to Net Income

The discussion in "Results of Operations" includes references to our Adjusted EBITDA results. Adjusted EBITDA is defined as net income attributable to the Company before the effect of net interest expense, income taxes, depreciation, depletion and amortization and the amortization of acquired sales contracts. Adjusted EBITDA may also be adjusted for items that may not reflect the trend of future results. We believe that Adjusted EBITDA presents a useful measure of our ability to service and incur debt based on ongoing operations. Investors should be aware that our presentation of Adjusted EBITDA may not be comparable to similarly titled measures used by other companies. The table below shows how we calculate Adjusted EBITDA.

	Year Ended December 31,		
	2012	2011	2010
Reported Segment Adjusted EBITDA	$ 877,283	$ 1,044,688	$ 788,741
Corporate and other[1]	(188,829)	(123,550)	(64,622)
Adjusted EBITDA	688,454	921,138	724,119
Income tax expense (benefit)	333,717	7,589	(17,714)
Interest expense, net	(312,148)	(226,877)	(140,100)
Depreciation, depletion and amortization	(525,508)	(466,587)	(365,066)
Amortization of acquired sales contracts, net	25,189	22,069	(35,606)
Mine closure and asset impairment costs	(523,568)	(7,316)	—
Goodwill impairment	(346,423)	—	—
Acquisition and transition costs	—	(56,885)	—
Other nonoperating expenses	(23,668)	(51,448)	(6,776)
Net income (loss) attributable to Arch Coal	$ (683,955)	$ 141,683	$ 158,857

(1) Corporate and other Adjusted EBITDA includes primarily selling, general and administrative expenses, income from our equity investments, certain changes in fair value of coal derivatives and coal trading activities, and net gains on asset sales.

Liquidity and Capital Resources

Our primary sources of cash are coal sales to customers, borrowings under our credit facilities and other financing arrangements, and debt and equity offerings related to significant transactions. Excluding any significant mineral reserve acquisitions, we generally satisfy our working capital requirements and fund capital expenditures and debt-service obligations with cash generated from operations or borrowings under our lines of credit. The borrowings under these arrangements are classified as current if the underlying credit facilities expire within one year or if, based on cash projections and management plans, we do not have the intent to replace them on a long-term basis. Such plans are subject to change based on our cash needs.

Financing Activities

On May 16, 2012, we entered into an amendment to our senior secured revolving credit facility that amended certain financial maintenance covenants, suspending our compliance with the debt-to-EBITDA ratio, easing other financial covenants through September 2014 and adding defined minimum EBITDA targets. The amendment also reduced the quarterly dividend we may pay on our common stock to $0.03 per share. The maximum borrowing capacity of the revolving credit facility was reduced from $2 billion to $600 million. In conjunction with the amendment, we borrowed $1.4 billion under a six-year secured term loan facility, issued at a 1% discount. The term loan contains no financial maintenance covenants, is prepayable and is secured by the same assets as borrowings under the revolving credit facility. Quarterly principal payments of $3.5 million began in September 2012, plus interest at a rate of the greater of a LIBOR-based rate or 1.25%, plus 450 basis points. The proceeds of the term loan were used to retire all outstanding borrowings under the revolving credit facility and the outstanding $450.0 million principal amount of 6.75% Senior Notes due 2013 issued by Arch Western Finance, LLC ("Arch Western Finance"), our indirect subsidiary.

On May 16, 2012, Arch Western Finance accepted for purchase approximately $304.0 million in aggregate principal amount of its 6.75% Senior Notes due 2013 (the "Arch Western Notes) in an initial settlement pursuant to the terms of its tender offer and consent solicitation, which commenced on May 1, 2012, and called for redemption all of the remaining Arch Western Notes outstanding after the completion of the tender offer. The consideration for each $1,000 of principal purchased under the tender offer and consent solicitation was $1,002.50, for a total purchase consideration of $304.8 million. On May 30, 2012, the remaining Arch Western Notes with an outstanding principal amount of $146.0 million were redeemed at par value.

On November 21, 2012, we issued $375.0 million aggregate principal amount of 9.875% senior unsecured notes due 2019 (the "9.875% Notes") at an issue price of 95.934% of the face amount. Also on November 21, 2012, we borrowed an incremental $250.0 million under our term loan facility at a 1% discount at the same rate of interest as the initial borrowing discussed previously. The principal payments on the term loan increased to $4.125 million per quarter as a result of the incremental borrowing. Under the terms of the credit agreement, the incremental term loan reduced the size of our revolving credit facility to $350 million from $600 million.

In entering these transactions, we preserved our liquidity by exchanging availability under credit lines for a greater cash position on the balance sheet to be used for general corporate purposes. At the same time, we amended its senior secured revolving credit facility to relax financial maintenance covenants and eliminate the minimum EBITDA targets until December 31, 2015.

In June 2011, we issued equity and debt securities to finance the ICG acquisition. On June 8, 2011, we sold 48 million shares of our common stock at a public offering price of $27.00 per share pursuant to an automatically effective shelf registration statement on Form S-3, a prospectus previously filed and a related prospectus supplement filed in June 2011. On July 8, 2011, we issued an additional 0.7 million shares of our common stock under the same terms and conditions to cover underwriters' over-allotments for net proceeds of $18.4 million. On June 14, 2011, we issued $1.0 billion in aggregate principal amount of 7.0% senior unsecured notes due in 2019 at par ("2019 Notes") and $1.0 billion in aggregate principal amount of 7.25% senior unsecured notes due in 2021 at par ("2021 Notes"). We secured bridge financing to ensure that funds would be available to us, if needed, to close the transaction. While we did not draw on the line of credit, we incurred costs of $49.9 million related to the bridge financing.

We believe that cash on hand, highly liquid investments, cash generated from operations, and borrowings under our credit facilities or other financing arrangements will be sufficient to meet our working capital requirements and anticipated capital expenditures in 2013 and for the foreseeable future. As a result of the refinancing activities discussed previously, we have no financial maintenance covenants until the end of 2015 and we have no significant debt maturities until 2016. Our ability to satisfy debt service obligations, to fund planned capital expenditures, to make acquisitions, to repurchase our common shares and to pay dividends in the future will depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry and financial, business and other factors, some of which are beyond our control.

Our indebtedness consisted of the following at December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(In thousands)	
Indebtedness to banks under credit facilities	$ —	$ 481,300
Term loan ($1.65 billion face value) due 2018	1,627,384	—
6.75% senior notes ($450.0 million face value) due 2013	—	450,971
8.75% senior notes ($600.0 million face value) due 2016	590,999	588,974
7.00% senior notes due 2019 at par	1,000,000	1,000,000
9.875% senior notes ($375.0 million face value) due 2019	360,042	—
7.25% senior notes due 2020 at par	500,000	500,000
7.25% senior notes due 2021 at par	1,000,000	1,000,000
Other	40,350	21,903
	5,118,775	4,043,148
Less current maturities of debt and short-term borrowings	32,896	280,851
Long-term debt	$ 5,085,879	$ 3,762,297

Credit Facilities

Borrowings under our senior secured revolving credit facility bear interest at a floating rate based on LIBOR determined by reference to our senior secured leverage ratio, as calculated in accordance with the underlying credit agreement. The credit facility has a five-year term that expires on June 14, 2016 and is secured by substantially all of our assets as well as its ownership interests in substantially all of its subsidiaries. Commitment fees of 0.50% to 0.75% per annum are payable on the average unused daily balance of the revolving credit facility.

We also maintain an accounts receivable securitization program under which eligible trade receivables are sold, without recourse, to a multiseller, assetbacked commercial paper conduit. The entity through which these receivables are sold is consolidated into our consolidated financial statements. We may borrow and draw letters of credit against the facility, and pays facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit). The total aggregate borrowings and letters of credit are limited by eligible accounts receivable, as defined under the terms of the agreement. The credit facility supporting the borrowings under the program is subject to renewal annually, and expires on December 10, 2013.

Financial covenant requirements relating to our senior notes may restrict the amount of unused capacity available to us for borrowings and letters of credit.

Our average borrowing level under these programs was approximately $199 million and $183 million for the years ended December 31, 2012 and 2011, respectively. On June 14, 2011, we terminated our commercial paper placement program and the supporting credit facility.

Senior Notes

We have outstanding an aggregate principal amount of $600.0 million of 8.75% senior notes due 2016 (the "2016 Notes") that were issued at an initial issue price of 97.464% of face amount. Interest is payable on the 2016 Notes on February 1 and August 1 of each year. At any time on or after August 1, 2013, we may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.375% for notes redeemed between August 1, 2013 and July 31, 2014; 102.188% for notes redeemed between August 1, 2014 and July 31, 2015; and 100% for notes redeemed on or after August 1, 2015. In addition, prior to August 1, 2012, at any time and on one or more occasions, we may redeem an aggregate principal amount of the 2016 Notes not to exceed 35% of the original aggregate principal amount of the notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 108.750%.

On August 9, 2010, we issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 (the "2020 Notes") at par. Interest is payable on the 2020 Notes on April 1 and October 1 of each year. At any time on or after October 1, 2015, we may redeem some or all of the notes. The redemption price reflected as a percentage of the principal amount is: 103.625% for notes redeemed between October 1, 2015 and September 30, 2016; 102.417% for notes redeemed between October 1, 2016 and September 30, 2017; 101.208% for notes redeemed between October 1, 2017 and September 30, 2018; and 100% for notes redeemed on or after October 1, 2018. In addition, at any time and on one or more occasions prior to October 1, 2013, we may redeem an aggregate principal amount of 2016 Notes not to exceed 35% of the original aggregate principal amount of the notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 107.250%.

Interest is payable on the 2019 Notes and 2021 Notes on June 15 and December 15 of each year. At any time prior to June 15, 2014, we may redeem up to 35% of the aggregate principal amount of each of the 2019 Notes and 2021 Notes, plus accrued and unpaid interest, with the net proceeds from certain equity offerings. We may redeem the 2019 Notes prior to June 15, 2015 and the 2021 Notes prior to June 15, 2016 at the respective make-whole prices set forth in the indenture. On or after June 15, 2015, we may redeem the 2019 Notes for cash at redemption prices, reflected as a percentage of the principal amount, of: 103.5% from June 15, 2015 through June 14, 2016; 101.75% from June 15, 2016 through June 14, 2017; and 100% beginning on June 15, 2017. On or after June 15, 2016, we may redeem the 2021 Notes for cash at redemption prices, reflected as a percentage of the principal amount, of: 103.625% from June 15, 2016 through June 14, 2017; 102.417% from June 15, 2017 through June 14, 2018; 101.208% from June 15, 2018 through June 14, 2019; and 100% beginning on June 15, 2019. In each case, accrued and unpaid interest at the redemption date is due upon redemption.

Interest is payable annually on the 9.875% Notes on June 15 and December 15 beginning on June 15, 2013. At any time on or after December 15, 2016, we may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.938% for notes redeemed between December 15, 2016 and December 14, 2017; 102.469% for notes redeemed between December 15, 2017 and December 14, 2018; and 100% for notes redeemed on or after December 15, 2018. In addition, at any time and on one or more occasions prior to December 15, 2015, we may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 109.875%.

The senior unsecured notes are guaranteed by substantially all of our subsidiaries, excluding Arch Receivable Company, LLC, which is the conduit for our accounts receivable securitizaton program, and our subsidiaries outside the U.S.

ICG Debt

We legally discharged our obligation under ICG's 9.125% senior notes by depositing funds with the Trustee to redeem the debt. On July 14, 2011, all of the outstanding 9.125% senior notes were redeemed at an aggregate price of $251.4 million, including the required make-whole premium, plus accrued interest of $5.2 million, and the remainder of the deposit was returned to us.

At the acquisition date, ICG's 4.00% convertible senior notes with a fair value of $298.5 million and 9.00% convertible senior notes with a fair value of $1.7 million ("convertible notes") became convertible into cash, pursuant to the amended indentures governing the convertible notes, at a calculated conversion rate of $2,614.6848 for each $1,000 in principal amount surrendered for conversion for the 4.00% convertible notes and $2,392.73414 for the 9.00% convertible notes for conversions occurring prior to August 17, 2011.

At the acquisition date, other ICG debt had a fair value of approximately $54.0 million and consisted mainly of equipment notes and insurance notes payable. Any remaining amounts are included in "other debt".

Availability

At December 31, 2012, we had cash on hand of $784.6 million, $234.3 million invested in highly liquid, interest-bearing securities and additional liquidity of $364 million, consisting primarily of available borrowing capacity under lines of credit.

We have filed a universal shelf registration statement on Form S-3 with the SEC that allows us to offer and sell from time to time an unlimited amount of unsecured debt securities consisting of notes, debentures, and other debt securities, common stock, preferred stock, warrants, or units. Related proceeds could be used for general corporate purposes, including repayment of debt, capital expenditures, possible acquisitions and any other purposes that may be stated in any related prospectus supplement.

The following is a summary of cash provided by or used in each of the indicated types of activities during the past three years:

	Year Ended December 31,		
	2012	2011	2010
	(Dollars in thousands)		
Cash provided by (used in):			
Operating activities	$ 332,804	$ 642,242	$ 697,147
Investing activities	(649,166)	(3,496,916)	(389,129)
Financing activities	962,835	2,899,230	(275,563)

Cash provided by operating activities decreased in the year ended December 31, 2012 compared to 2011, driven by the decrease in our profitability resulting from poor market conditions. Cash provided by operating activities decreased in 2011 compared to 2010, despite higher operating income adjusted for non-cash items, driven largely by an increase in inventory costs, as well as a benefit in 2010 from the timing of payments on accounts and production taxes payable.

We used less cash in investing activities in the year ended December 31, 2012 compared to the amount used in 2011, primarily due to the acquisition of ICG in 2011, as well as a decrease in investments in affiliates and prepaid royalties in 2012. There was also a decrease in capital expenditures of approximately $145.7 million during year ended December 31, 2012 when compared with 2011, due to cash management efforts, however, we have continued with certain development projects. We spent approximately $73 million in 2011 and $195 million during 2012 on the development of the Leer mine, and we expect to spend approximately $100 million during 2013 on its completion. During 2010, we made payments of $118.2 million for coal reserves in Montana and spent $26.0 million on a preparation plant at the West Elk mine.

In addition, during 2012, we invested approximately $237 million of cash proceeds from the term loan in highly liquid marketable debt securities and we purchased the noncontrolling interest in Arch Western for $17.5 million.

Cash provided by financing activities was approximately $963 million in the year ended December 31, 2012, compared to approximately $2.9 billion in 2011. In 2012, the proceeds from the $1.6 billion term loan facility were used, in part, to retire the remaining outstanding senior secured notes due in 2013 and outstanding borrowings under lines of credit, with the remainder, along with the proceeds from the sale of the 9.875% Notes, to be used for general corporate purposes. In 2011, the proceeds from the issuance of $2.0 billion in senior notes in 2011 and shares issued in 2011 were used to finance the ICG acquisition. In 2010 we used the net proceeds from the offering of the 2020 notes and cash on hand to fund the redemption of $500.0 million aggregate principal amount of our outstanding. Arch Western Notes at a redemption price of 101.125%. We paid financing costs of $50.6 million in 2012, $114.8 million in 2011 and $12.8 million in 2010 relating to these transactions.

We paid dividends of $42.4 million in 2012, $80.7 million in 2011 and $63.4 million in 2010.

Ratio of Earnings to Fixed Charges

The following table sets forth our ratios of earnings to combined fixed charges and preference dividends for the periods indicated:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Ratio of earnings to combined fixed charges and preference dividends(1)	N/A(2)	1.49x	2.17x	1.26x	4.91x

(1) Earnings consist of income from operations before income taxes and are adjusted to include only distributed income from affiliates accounted for on the equity method and fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense.

(2) Total losses for ratio calculation were $658.9 million and total fixed charges were $344.0 million for the year ended December 31, 2012

Contractual Obligations

	Payments Due by Period				
	2013	2014 - 2015	2016 - 2017	After 2017	Total
	(Dollars in thousands)				
Long-term debt, including related interest	$ 397,067	$ 764,574	$ 1,286,404	$ 5,054,079	$ 7,502,124
Operating leases	26,837	42,857	17,013	5,334	92,041
Coal lease rights	109,695	200,989	126,524	147,103	584,311
Coal purchase obligations	15,073	24,073	26,677	—	65,823
Unconditional purchase obligations	201,122	246,297	174,351	445,599	1,067,369
Total contractual obligations	$ 749,794	$ 1,278,790	$ 1,630,969	$ 5,652,115	$ 9,311,668

The related interest on long-term debt was calculated using rates in effect at December 31, 2012 for the remaining term of outstanding borrowings.

Coal lease rights represent non-cancelable royalty lease agreements, as well as lease bonus payments due.

Our coal purchase obligations include purchase obligations in the over-the-counter market, as well as unconditional purchase obligations with coal suppliers.

Unconditional purchase obligations include open purchase orders and other purchase commitments, which have not been recognized as a liability. The commitments in the table above relate to contractual commitments for the purchase of materials and supplies, payments for services and capital expenditures.

The table above excludes our asset retirement obligations. Our consolidated balance sheet reflects a liability of $448.6 million for asset retirement obligations that arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Asset retirement obligations are recorded at fair value when incurred and accretion expense is recognized through the expected date of settlement. Determining the fair value of asset retirement obligations involves a number of estimates, as discussed in the section entitled "Critical Accounting Policies", including the timing of payments to satisfy the obligations. The timing of payments to satisfy asset retirement obligations is based on numerous factors, including mine closure dates. You should see the notes to our consolidated financial statements for more information about our asset retirement obligations.

The table above also excludes certain other obligations reflected in our consolidated balance sheet, including estimated funding for pension and postretirement benefit plans and worker's compensation obligations. The timing of contributions to our pension plans varies based on a number of factors, including changes in the fair value of plan assets and actuarial assumptions. You should see the section entitled "Critical Accounting Policies" for more information about these assumptions. We expect to make contributions of $0.9 million to our pension plans in 2013, which is impacted by the Moving Ahead for Progress in the 21st Century Act (MAP-21) enacted July 6, 2012. MAP-21 does not reduce our obligations under the plan, but redistributes the timing of required payments by providing near term funding relief for sponsors under the Pension Protection Act.

You should see the notes to our consolidated financial statements for more information about the amounts we have recorded for workers' compensation and pension and postretirement benefit obligations.

The table above excludes future contingent payments of up to $72.9 million related to development financing for certain of our equity investees. Our obligation to make these payments, as well as the timing of any payments required, is contingent upon a number of factors, including project development progress, receipt of permits and the obtaining of construction financing.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements. These arrangements include guarantees, indemnifications, financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds, corporate guarantees (e.g., self bonds) and letters of credit to secure our financial obligations for reclamation, workers' compensation, coal lease obligations and other obligations as follows as of December 31, 2012:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other	Total
			(Dollars in thousands)		
Self bonding	$ 388,445	$ —	$ —	$ —	$ 388,445
Surety bonds	262,852	60,742	12,450	146,693	482,737
Letters of credit	18,000	—	48,697	32,167	98,864

In addition, we have agreed to continue to provide surety bonds for certain Magnum obligations, primarily reclamation. The surety bonding amounts are mandated by the state and are not directly related to the estimated cost to reclaim the properties. At December 31, 2012, we had $35.3 million of surety bonds remaining related to Magnum properties, however Patriot Coal has posted letters of credit of $16.7 million in our favor.

Critical Accounting Policies

We prepare our financial statements in accordance with accounting principles that are generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities. Management bases our estimates and judgments on historical experience and other factors that are believed to be reasonable under the circumstances. Additionally, these estimates and judgments are discussed with our audit committee on a periodic basis. Actual results may differ from the estimates used under different assumptions or conditions. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. We believe that of these significant accounting policies, the following may involve a higher degree of judgment or complexity:

Derivative Financial Instruments

We utilize derivative instruments to manage exposures to commodity prices. Additionally, we may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by us over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a fair value hedge, we hedge the risk of changes in the fair value of a firm commitment, typically a fixed-price coal sales contract. Changes in both the hedged firm commitment and the fair value of a derivative used as a hedge instrument in a fair value hedge are recorded in earnings. In a cash flow hedge, we hedge the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income. Amounts in other comprehensive income are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged.

Any ineffective portion of a hedge is recognized immediately in earnings. Ineffectiveness was insignificant for the years ended December 31, 2012, 2011 and 2010.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking various hedge transactions. We evaluate the effectiveness of our hedging relationships both at the hedge inception and on an ongoing basis.

Asset Retirement Obligations

Our asset retirement obligations arise from SMCRA and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. Significant reclamation activities include reclaiming refuse and slurry ponds, reclaiming the pit and support acreage at surface mines, and sealing portals at deep mines. Our asset retirement obligations are initially recorded at fair value, or the amount at which the obligations could be settled in a current transaction between willing parties. This involves determining the present value of estimated future cash flows on a mine-by-mine basis based upon current permit requirements and various estimates and assumptions, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. We estimate disturbed acreage based on approved mining plans and related engineering data. Since we plan to use internal resources to perform the majority of our reclamation activities, our estimate of reclamation costs involves estimating third-party profit margins, which we base on our historical experience with contractors that perform certain types of reclamation activities. We base productivity assumptions on historical experience with the equipment that we expect to utilize in the reclamation activities. In order to determine fair value, we discount our estimates of cash flows to their present value. We base our discount rate on the rates of treasury bonds with maturities similar to expected mine lives, adjusted for our credit standing.

Accretion expense is recognized on the obligation through the expected settlement date. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing and extent of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled. We expect our actual cost to reclaim our properties will be less than the expected cash flows used to determine the asset retirement obligation. At December 31, 2012, our balance sheet reflected asset retirement obligation liabilities of $448.6 million, including amounts classified as a current liability. As of December 31, 2012, we estimate the aggregate undiscounted cost of final mine closures to be approximately $1.0 billion.

See the rollforward of the asset retirement obligation liability in "Financial Statements and Supplementary Data, Note 14 to the consolidated financial statements."

Goodwill

In a business combination, goodwill represents the excess of the purchase price over the fair value assigned to the net tangible and identifiable intangible assets acquired. We test goodwill for impairment annually as of the beginning of the fourth quarter, or when circumstances indicate a possible impairment may exist. If the results of the testing indicate that the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the fair value of goodwill must be calculated. An impairment loss generally would be recognized when the carrying amount of goodwill exceeds the implied fair value of goodwill, determined by subtracting the fair value of the other assets and liabilities associated with the reporting unit from the total fair value of the reporting unit. The fair value of a reporting unit is determined using a discounted cash flow ("DCF") technique. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate and projections of sales volumes and prices and costs to produce. We apply a probability weighting to different scenarios that are developed in this estimation process. This income approach is compared to a market approach for reasonableness of the estimates used.

Our estimates of selling prices at the valuation date reflect assumptions about coal consumption and supply for the respective coal market. These prices are compared to market pricing information from third party forecasts for reasonableness, taking into account for the impact of coal quality on pricing. Our estimates of sales and production volumes are also based on the assumptions about coal consumption and supply discussed previously.

As discussed in the consolidated financial statements Note 7, "Goodwill", we recognized goodwill impairment charges in 2012. In the second quarter of 2012, weak demand for thermal coal and our production cuts in response to market conditions, indicated that the fair value of our goodwill could be less than its carrying value and we performed step one of the goodwill impairment test. The impact of lower demand on near term sales volumes and pricing significantly impacted the fair value of the Black Thunder reporting unit, which did not exceed the carrying value. We made estimates of the fair value of assets and liabilities of the Black Thunder reporting unit and determined that the allocated goodwill was fully impaired, and recognized an impairment charge of $115.8 million in the second quarter of 2012. A subsequent valuation of the assets and liabilities supported that the goodwill allocated to Black Thunder had no implied fair value.

The goodwill amounts allocated to certain reporting units in our Appalachia segment are sensitive to volatility in the demand for metallurgical coal. During the 2012, metallurgical prices fell 50% from the peaks reached during 2011, when the reporting units were acquired with our purchase of ICG. This caused the fair value of two of these reporting units to fall below their carrying value. The allocated goodwill of $214.9 million for those reporting units was determined to be fully impaired, based on current market conditions and tax benefits assumed to accrue to market participants. We recognized this impairment charge in the fourth quarter of 2012.

The remaining two reporting units in the Appalachia segment are in the development stage at this time, and as such, their fair values are less sensitive to changes in near-term metallurgical coal pricing. Changes in the long-term outlook in the global demand for metallurgical coal from the U.S. could have a negative effect on the value of these reporting units in the future.

Employee Benefit Plans

We have non-contributory defined benefit pension plans covering certain of our salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The actuarially-determined funded status of the defined benefit plans is reflected in the balance sheet.

The calculation of our net periodic benefit costs (pension expense) and benefit obligation (pension liability) associated with our defined benefit pension plans requires the use of a number of assumptions. Changes in these assumptions can result in different pension expense and liability amounts, and actual experience can differ from the assumptions.

- The expected long-term rate of return on plan assets is an assumption reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. We establish the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The pension plan's investment targets are 65% equity, 30% fixed income securities and 5% cash. Investments are rebalanced on a periodic basis to approximate these targeted guidelines. The long-term rate of return assumption used to determine pension expense was 7.75% and 8.5% for 2012 and 2011, respectively. The long-term rate of return assumptions are less than the plan's actual life-to-date returns. Any difference between the actual experience and the assumed experience is recorded in other comprehensive income and amortized into earnings in the future. The impact of lowering the expected long-term rate of return on plan assets 0.5% for 2012 would have been an increase in expense of approximately $1.4 million.

- The discount rate represents our estimate of the interest rate at which pension benefits could be effectively settled. Assumed discount rates are used in the measurement of the projected, accumulated and vested benefit obligations and the service and interest cost components of the net periodic pension cost. In estimating that rate, rates of return on high-quality fixed-income debt instruments are required. We utilize a bond portfolio model that includes bonds that are rated "AA" or higher with maturities that match the expected benefit payments under the plan. The discount rate used to determine pension expense was 4.91% for 2012 and 5.71% for 2011. The impact of lowering the discount rate 0.5% for 2012 would have been an increase in expense of approximately $4.5 million.

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period, which represents the average amount of time before participants vest in their benefits.

For the measurement of our 2012 year-end pension obligation and pension expense for 2013, we used a discount rate of 4.13%.

We also currently provide certain postretirement medical and life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement benefit plans are contributory, with retiree contributions adjusted periodically, and contain other cost-sharing features such as deductibles and coinsurance.

Actuarial assumptions are required to determine the amounts reported as obligations and costs related to the postretirement benefit plan. The discount rate assumption reflects the rates available on high-quality fixed-income debt instruments at year-end and is calculated in the same manner as discussed above for the pension plan. The discount rate used to calculate the postretirement benefit expense was 4.52% and 5.23% for 2012 and 2011, respectively.

Had the discount rate been lowered by 0.5% in 2012, we would have incurred additional expense of $0.3 million.

For the measurement of our 2012 year-end other postretirement benefits obligation and postretirement expense for 2013, we used a discount rate of 3.64%.

Income Taxes

We provide for deferred income taxes for temporary differences arising from differences between the financial statement and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates expected to be in effect when the related taxes are expected to be paid or recovered. We initially recognize the effects of a tax position when it is more than 50 percent likely, based on the technical merits, that the position will be sustained upon examination, including resolution of the related appeals or litigation processes, if any. Our determination of whether or not a tax position has met the recognition threshold considers the facts, circumstances, and information available at the reporting date. A valuation allowance may be recorded to reflect the amount of future tax benefits that management believes are not likely to be realized. We reassess our ability to realize our deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. In determining the appropriate valuation allowance, we take into account expected future taxable income, available tax planning strategies and the reversal of temporary differences. If future taxable income is lower than expected or if expected tax planning strategies are not available as anticipated, we may record additional valuation allowance through income tax expense in the period such determination is made.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We manage our commodity price risk for our non-trading, thermal coal sales through the use of long-term coal supply agreements, and to a limited extent, through the use of derivative instruments. Sales commitments in the metallurgical coal market are typically not long-term in nature, and we are therefore subject to the fluctuations in the market pricing.

At December 31, 2012, our commitments for 2013 and 2014 are as follows:

	2013		2014	
	Tons	$ per ton	Tons	$ per ton
Powder River Basin				
Committed, Priced	86.3	$ 13.37	51.1	$ 14.22
Committed, Unpriced	9.1		13.6	
Western Bituminous				
Committed, Priced	11.4	$ 38.74	7.4	$ 40.86
Committed, Unpriced	1.7		0.2	
Appalachia				
Committed, Priced Thermal	5.2	$ 64.72	1.7	$ 53.98
Committed, Unpriced Thermal	0.4		0.3	
Committed, Priced Metallurgical	3.9	$ 93.37	—	$ —
Committed, Unpriced Metallurgical	0.2		—	
Illinois Basin				
Committed, Priced	2.1	$ 42.50	1.7	$ 42.33

We are also exposed to commodity price risk in our coal trading activities, which represents the potential future loss that could be caused by an adverse change in the market value of coal. Our coal trading portfolio included forward, swap and put and call option contracts at December 31, 2012. The estimated future realization of the value of the trading portfolio is $1.1 million of losses in the remainder of 2013 and $1.5 million of gains in 2014.

We monitor and manage market price risk for our trading activities with a variety of tools, including Value at Risk (VaR), position limits, management alerts for mark to market monitoring and loss limits, scenario analysis, sensitivity analysis and review of daily changes in market dynamics. Management believes that presenting high, low, end of year and average VaR is the best available method to give investors insight into the level of commodity risk of our trading positions. Illiquid positions, such as long-dated trades that are not quoted by brokers or exchanges, are not included in VaR.

VaR is a statistical one-tail confidence interval and down side risk estimate that relies on recent history to estimate how the value of the portfolio of positions will change if markets behave in the same way as they have in the recent past. While presenting VaR will provide a similar framework for discussing risk across companies, VaR estimates from two independent sources are rarely calculated in the same way. Without a thorough understanding of how each VaR model was calculated, it would be difficult to compare two different VaR calculations from different sources. The level of confidence is 95%. The time across which these possible value changes are being estimated is through the end of the next business day. A closed-form delta-neutral method used throughout the finance and energy sectors is employed to calculate this VaR. VaR is back tested to verify usefulness.

On average, portfolio value should not fall more than VaR on 95 out of 100 business days. Conversely, portfolio value declines of more than VaR should be expected, on average, 5 out of 100 business days. When more value than VaR is lost due to market price changes, VaR is not representative of how much value beyond VaR will be lost.

During the year ended December 31, 2012, VaR for our coal trading positions that are recorded at fair value through earnings ranged from under $0.1 million to $1.0 million The linear mean of each daily VaR was $0.4 million. The final VaR at December 31, 2012 was $0.5 million.

We are exposed to fluctuations in the fair value of coal derivatives that we enter into to manage the price risk related to future coal sales, but for which we do not elect hedge accounting. Any gains or losses on these derivative instruments would be offset in the pricing of the physical coal sale. During the year ended December 31, 2012 VaR for our risk management positions that are recorded at fair value through earnings ranged from under $0.8 million to $4.2 million. The linear mean of each daily VaR was $2.2 million. The final VaR at December 31, 2012 was $0.8 million.

We are also exposed to the risk of fluctuations in cash flows related to our purchase of diesel fuel. We expect to use approximately 57 to 67 million gallons of diesel fuel for use in our operations during 2013. We enter into forward physical purchase contracts, as well as purchased heating oil options, to reduce volatility in the price of diesel fuel for our operations. At December 31, 2012, we had protected the price of substantially all of our 2013 purchases. A $0.25 per gallon decrease in the price of heating oil would not result in an increase in our expense related to the heating oil derivatives.

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At December 31, 2012, of our $5.1 billion principal amount of debt outstanding, approximately $1.7 billion of outstanding borrowings have interest rates that fluctuate based on changes in the market rates. An increase in the interest rates related to these borrowings of 25 basis points would not result in an annualized increase in interest expense based on interest rates in effect at December 31, 2012.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements and consolidated financial statement schedule of Arch Coal, Inc. and subsidiaries are included in this Annual Report on Form 10-K beginning on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

We performed an evaluation under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2012. Based on that evaluation, our management, including our chief executive officer and chief financial officer, concluded that the disclosure controls and procedures were effective as of such date. There were no changes in our internal control over financial reporting during the three months ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

We incorporate by reference the report of independent registered public accounting firm and management's report on internal control over financial reporting included on pages F-3 and F-4, respectively, of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 401 of Regulation S-K is included under the caption "Director Qualifications, Diversity and Biographies" in our 2013 Proxy Statement and in Part I of this report under the caption "Executive Officers." The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance Guidelines and Code of Business Conduct," "Nominating Process for Election of Directors" and "Board Meetings and Committees" in our 2013 Proxy Statement. Such information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K is included under the captions "Executive Compensation," "Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Personnel and Compensation Committee Report" (which is furnished) in our 2013 Proxy Statement and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Items 201(d) and 403 of Regulation S-K is included under the captions "Equity Compensation Plan Information," "Security Ownership of Directors and Executive Officers" and "Security Ownership of Certain Beneficial Owners" in our 2013 Proxy Statement and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Items 404 and 407(a) of Regulation S-K is included under the caption "Directors and Corporate Governance Practices" in our 2013 Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 9(e) of Schedule 14A is included under the caption "Fees Paid to Auditors" in our 2013 Proxy Statement and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Financial Statements

Reference is made to the index set forth on page F-1 of this report.

Financial Statement Schedules

The following financial statement schedule of Arch Coal, Inc. is at the page indicated:

Schedule	Page
Valuation and Qualifying Accounts	F-58

All other financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

Exhibits

Reference is made to the Exhibit Index beginning on page 83 of this report.

Table of Contents

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Arch Coal, Inc.

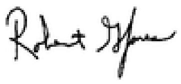
John W. Eaves
President and Chief Executive Officer

March 1, 2013

Signatures	Capacity	Date
John W. Eaves	President and Chief Executive Officer, Director (Principal Executive Officer)	March 1, 2013
John T. Drexler	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 1, 2013
John W. Lorson	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2013
Steven F. Leer	Chairman of the Board of Directors	March 1, 2013
* David D. Freudenthal	Director	March 1, 2013
* Patricia F. Godley	Director	March 1, 2013
* Paul T. Hanrahan	Director	March 1, 2013

Signatures	Capacity	Date
* Douglas H. Hunt	Director	March 1, 2013
* J. Thomas Jones	Director	March 1, 2013
* George C. Morris III	Director	March 1, 2013
* A. Michael Perry	Director	March 1, 2013
* Theodore D. Sands	Director	March 1, 2013
* Wesley M. Taylor	Director	March 1, 2013
* Peter I. Wold	Director	March 1, 2013

*By:



Robert G. Jones,
Attorney-in-Fact

Exhibit Index

Exhibit	Description
2.1	Purchase and Sale Agreement, dated as of December 31, 2005, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on January 6, 2006).
2.2	Amendment No. 1 to the Purchase and Sale Agreement, dated as of February 7, 2006, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated by reference to Exhibit 2.1 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2005).
2.3	Amendment No. 2 to the Purchase and Sale Agreement, dated as of April 27, 2006, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2006).
2.4	Amendment No. 3 to the Purchase and Sale Agreement, dated as of August 29, 2007, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended September 30, 2007).
2.5	Agreement, dated as of March 27, 2008, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2008).
2.6	Amendment No. 1 to Agreement, dated as of February 5, 2009, by and between Arch Coal, Inc. and Magnum Coal Company (incorporated herein by reference to Exhibit 2.6 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
2.7	Agreement and Plan of Merger, dated as of May 2, 2011, by and among Arch Coal, Inc., Atlas Acquisition Corp. and International Coal Group, Inc. (incorporated herein by reference to Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on May 3, 2011).
2.8	Amendment to Agreement and Plan of Merger, dated as of May 26, 2011 among Arch Coal, Inc., Atlas Acquisition Corp. and International Coal Group, Inc. (incorporated herein by reference to Exhibit 2.8 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
3.1	Restated Certificate of Incorporation of Arch Coal, Inc. (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on May 5, 2006).
3.2	Arch Coal, Inc. Bylaws, as amended effective as of December 5, 2008 (incorporated herein by reference to Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 10, 2008).
4.1	Indenture, dated as of July 31, 2009 by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on July 31, 2009).
4.2	First Supplemental Indenture, dated as of February 8, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010).
4.3	Second Supplemental Indenture, dated as of March 12, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.5 to the registrant's Registration Statement on Form S-4 filed on April 7, 2010)
4.4	Third Supplemental Indenture, dated as of May 7, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010)
4.5	Fourth Supplemental Indenture, dated December 16, 2010, by and among Arch Coal West, LLC, Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.7 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).

Exhibit	Description
4.6	Fifth Supplemental Indenture, dated as of June 24, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.8 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
4.7	Sixth Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.9 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
4.8	Seventh Supplemental Indenture, dated as of July 2, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.9	Eighth Supplemental Indenture, dated as of July 31, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.10	Indenture, dated as of August 9, 2010, by and between Arch Coal, Inc. and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on August 9, 2010)
4.11	First Supplemental Indenture, dated as of August 9, 2010, by and among Arch Coal, Inc., the subsidiary guarantors named therein, and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on August 9, 2010)
4.12	Second Supplemental Indenture, dated as of December 16, 2010, by and among Arch Coal West, LLC, Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.7 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
4.13	Third Supplemental Indenture, dated as of June 24, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.13 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
4.14	Fourth Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.14 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
4.15	Fifth Supplemental Indenture, dated as of July 2, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.16	Sixth Supplemental Indenture, dated as of July 31, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.5 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.17	Indenture, dated as of June 14, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on June 14, 2011).
4.18	First Supplemental Indenture, dated as of July 5, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.16 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
4.19	Second Supplemental Indenture, dated as of October 7, 2011, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).

Exhibit	Description
4.20	Third Supplemental Indenture, dated as of July 2, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.21	Fourth Supplemental Indenture, dated as of July 31, 2012, by and among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.6 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2012).
4.22	Indenture, dated as of November 21, 2012, among Arch Coal, Inc., the subsidiary guarantors named therein and UMB Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 26, 2012).
4.23	Registration Rights Agreement, dated as of November 21, 2012, by and among Arch Coal, Inc., the guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the initial purchasers named therein (incorporated herein by reference to Exhibit 4.3 to the registrant's Current Report on Form 8-K filed on November 26, 2012).
10.1	Amended and Restated Credit Agreement, dated as of June 14, 2011, by and among the Company, the lenders party thereto, PNC Bank, National Association, as administrative agent and Bank of America, N.A., The Royal Bank of Scotland PLC and Citibank, N.A., as co-documentation agents (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the registrant on June 17, 2011).
10.2	Incremental Amendment, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the incremental term loan lenders party thereto, Bank of America, N.A., as Term Loan Administrative Agent, and Merrill Lynch, Pierce, Fenner & Smith Incorporated, PNC Capital Markets LLC, Morgan Stanley Senior Funding, Inc., Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, BBVA Securities Inc., RBS Securities Inc. and Union Bank, N.A., as Lead Arrangers, as Lead Arrangers (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on November 26, 2012).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the lenders party thereto, Bank of America, N.A., as Term Loan Administrative Agent, and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on November 26, 2012).
10.4	Third Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2012, by and among Arch Coal, Inc., as Borrower, the guarantors party thereto, the revolver lenders party thereto and PNC Bank, National Association, as Revolver Administrative Agent (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on November 26, 2012).
10.5*	Form of Employment Agreement for Chairman and Executive Officers of Arch Coal, Inc. (incorporated herein by reference to Exhibit 10.4 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.6	Coal Lease Agreement dated as of March 31, 1992, among Allegheny Land Company, as lessee, and UAC and Phoenix Coal Corporation, as lessors, and related guarantee (incorporated herein by reference to the Current Report on Form 8-K filed by Ashland Coal, Inc. on April 6, 1992).
10.7	Federal Coal Lease dated as of June 24, 1993 between the U.S. Department of the Interior and Southern Utah Fuel Company (incorporated herein by reference to Exhibit 10.17 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.8	Federal Coal Lease between the U.S. Department of the Interior and Utah Fuel Company (incorporated herein by reference to Exhibit 10.18 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.9	Federal Coal Lease dated as of July 19, 1997 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10.19 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).

Exhibit	Description
10.10	Federal Coal Lease dated as of January 24, 1996 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.11	Federal Coal Lease Readjustment dated as of November 1, 1967 between the U.S. Department of the Interior and the Thunder Basin Coal Company (incorporated herein by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.12	Federal Coal Lease effective as of May 1, 1995 between the U.S. Department of the Interior and Mountain Coal Company (incorporated herein by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.13	Federal Coal Lease dated as of January 1, 1999 between the Department of the Interior and Ark Land Company (incorporated herein by reference to Exhibit 10.23 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1998).
10.14	Federal Coal Lease dated as of October 1, 1999 between the U.S. Department of the Interior and Canyon Fuel Company, LLC (incorporated herein by reference to Exhibit 10 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).
10.15	Federal Coal Lease effective as of March 1, 2005 by and between the United States of America and Ark Land LT, Inc. covering the tract of land known as "Little Thunder" in Campbell County, Wyoming (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by the registrant on February 10, 2005).
10.16	Modified Coal Lease (WYW71692) executed January 1, 2003 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Rochelle" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).
10.17	Coal Lease (WYW127221) executed January 1, 1998 by and between the United States of America, through the Bureau of Land Management, as lessor, and Triton Coal Company, LLC, as lessee, covering a tract of land known as "North Roundup" in Campbell County, Wyoming (incorporated by reference to Exhibit 10.24 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004).
10.18	State Coal Lease executed October 1, 2004 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company and Arch Coal, Inc., as lessees, covering a tract of land located in Seiever County, Utah (incorporated by reference to Exhibit 10.20 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.19	State Coal Lease executed September 1, 2000 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Canyon Fuel Company, LLC, as lessee, for lands located in Carbon County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.20	Federal Coal Lease executed September 1, 1996 by and between the Bureau of Land Management, as lessor, and Canyon Fuel Company, LLC, as lessee, covering a tract of land known as "The North Lease" in Carbon County, Utah (incorporated by reference to Exhibit 10.22 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.21	State Coal Lease executed January 18, 2008 by and between The State of Utah, Thru School & Institutional Trust Lands Admin, as lessor, and Ark Land Company, as lessee, for lands located in Emery County, Utah (incorporated by reference to Exhibit 10.21 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2008).
10.22	Form of Indemnity Agreement between Arch Coal, Inc. and Indemnitee (as defined therein) (incorporated herein by reference to Exhibit 10.15 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.23*	Arch Coal, Inc. Incentive Compensation Plan For Executive Officers (incorporated herein by reference to Appendix B to the proxy statement on Schedule 14A filed by the registrant on March 22, 2010).

Exhibit	Description
10.24*	Arch Coal, Inc. Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.25*	Arch Coal, Inc. 1997 Stock Incentive Plan (as amended and restated on October 21, 2010) (incorporated herein by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on October 27, 2010).
10.26*	Arch Mineral Corporation 1996 ERISA Forfeiture Plan (incorporated herein by reference to Exhibit 10.20 to the Registration Statement on Form S-4 (Registration No. 333-28149) filed by the registrant on May 30, 1997).
10.27*	Arch Coal, Inc. Outside Directors' Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.4 of the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.28*	Arch Coal, Inc. Supplemental Retirement Plan (as amended on December 5, 2008) (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 11, 2008).
10.29*	Form of Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 24, 2006).
10.30*	Form of Non-Qualified Stock Option Agreement (for stock options granted prior to February 21, 2008) (incorporated herein by reference to Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2006).
10.31*	Form of 2008 Restricted Stock Unit Contract for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.32*	Form of 2008 Non-Qualified Stock Option Agreement for Messrs. Leer and Eaves (incorporated herein by reference to Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.33*	Form of Non-Qualified Stock Option Agreement (for stock options granted on or after February 21, 2008) (incorporated herein by reference to Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on February 27, 2008).
10.34*	Form of Performance Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on February 23, 2009).
10.35*	Form of 2011 Non-Qualified Stock Option Agreement (incorporated herein by reference to Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.36*	Form of 2011 Restricted Stock Unit Contract (incorporated herein by reference to Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.37*	Form of 2011 Restricted Stock Unit Contract for Non-Employee Directors (incorporated herein by reference to Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.38*	Form of 2011 Performance Unit Contract (incorporated herein by reference to Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2012).
10.39*	Form of Director Indemnity Agreement (incorporated herein by reference to Exhibit 10.40 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).
10.40	Amended and Restated Receivables Purchase Agreement, dated as of February 24, 2020, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc., Market Street Funding LLC, as issuer, the financial institutions from time to time party thereto, as LC Participants, and PNC Bank, National Association, as Administrator on behalf of the Purchasers and as LC Bank (incorporated herein by reference to Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the period ended March 31, 2010).
10.41	First Amendment to Amended and Restated Receivables Purchase Agreement, dated January 31, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated by reference to Exhibit 10.41 to the registrant's Annual Report on Form 10-K for the period ended December 31, 2010).

Exhibit	Description
10.42	Second Amendment to Amended and Restated Receivables Purchase Agreement dated June 15, 2011 (incorporated by reference to Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the period ended June 30, 2011).
10.43	Third Amendment to Amended and Restated Receivables Purchase Agreement dated November 21, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated herein by reference to Exhibit 10.38 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.44	Fourth Amendment to Amended and Restated Receivables Purchase Agreement dated December 13, 2011, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto (incorporated herein by reference to Exhibit 10.39 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2011).
10.45	Fifth Amendment to Amended and Restated Receivables Purchase Agreement dated December 11, 2012, among Arch Receivable Company, LLC, Arch Coal Sales Company, Inc. and the other parties thereto.
12.1	Computation of ratio of earnings to combined fixed charges and preference dividends.
21.1	Subsidiaries of the registrant.
23.1	Consent of Ernst & Young LLP.
23.2	Consent of Weir International, Inc.
24.1	Power of Attorney.
31.1	Rule 13a-14(a)/15d-14(a) Certification of John W. Eaves.
31.2	Rule 13a-14(a)/15d-14(a) Certification of John T. Drexler.
32.1	Section 1350 Certification of John W. Eaves.
32.2	Section 1350 Certification of John T. Drexler.
95	Mine Safety Disclosure Exhibit.
101	Interactive Data File (Form 10-K for the year ended December 31, 2012 filed in XBRL). The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

* Denotes management contract or compensatory plan arrangements.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements of Arch Coal, Inc. and subsidiaries and reports of independent registered public accounting firm follow.

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Arch Coal, Inc.

We have audited the accompanying consolidated balance sheets of Arch Coal, Inc. (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arch Coal, Inc. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Arch Coal Inc.'s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 1, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Arch Coal, Inc.

We audited Arch Coal Inc.'s (the Company's) internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Arch Coal, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arch Coal, Inc. as of December 31, 2012 and 2011, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012, and our report dated March 1, 2013, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
March 1, 2013

REPORT OF MANAGEMENT

The management of Arch Coal, Inc. (the "Company") is responsible for the preparation of the consolidated financial statements and related financial information in this annual report. The financial statements are prepared in accordance with accounting principles generally accepted in the United States and necessarily include some amounts that are based on management's informed estimates and judgments, with appropriate consideration given to materiality.

The Company maintains a system of internal accounting controls designed to provide reasonable assurance that financial records are reliable for purposes of preparing financial statements and that assets are properly accounted for and safeguarded. The concept of reasonable assurance is based on the recognition that the cost of a system of internal accounting controls should not exceed the value of the benefits derived. The Company has a professional staff of internal auditors who monitor compliance with and assess the effectiveness of the system of internal accounting controls.

The Audit Committee of the Board of Directors, comprised of independent directors, meets regularly with management, the internal auditors, and the independent auditors to discuss matters relating to financial reporting, internal accounting control, and the nature, extent and results of the audit effort. The independent auditors and internal auditors have full and free access to the Audit Committee, with and without management present.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Arch Coal, Inc. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Securities Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including its principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the criteria set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, management concluded that the Company's internal control over financial reporting is effective as of December 31, 2012.

The Company's independent registered public accounting firm, Ernst & Young LLP, has issued an audit report on the Company's internal control over financial reporting.

John W. Eaves	John T. Drexler
Chairman and Chief Executive Officer	*Senior Vice President and Chief Financial Officer*

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(In thousands, except per share data)		
REVENUES	$ 4,159,038	$ 4,285,895	$ 3,186,268
COSTS, EXPENSES AND OTHER OPERATING			
Cost of sales	3,438,013	3,267,910	2,395,812
Depreciation, depletion and amortization	525,508	466,587	365,066
Amortization of acquired sales contracts, net	(25,189)	(22,069)	35,606
Change in fair value of coal derivatives and coal trading activities, net	(16,590)	(2,907)	8,924
Coal derivative settlements, non-hedging	(43,990)	7	(4,542)
Selling, general and administrative expenses	134,299	119,056	118,177
Contract settlement resulting from Patriot Coal bankruptcy	58,335	—	—
Legal contingencies	(79,532)	—	—
Mine closure and asset impairment costs	523,568	7,316	—
Goodwill and other intangible asset impairment	346,423	—	—
Acquisition and transition costs	—	47,360	—
Gain on Knight Hawk transaction	—	—	(41,577)
Other operating income, net	(20,219)	(10,941)	(15,182)
	4,840,626	3,872,319	2,862,284
Income (loss) from operations	(681,588)	413,576	323,984
Interest expense, net:			
Interest expense	(317,626)	(230,186)	(142,549)
Interest income	5,478	3,309	2,449
	(312,148)	(226,877)	(140,100)
Other nonoperating expense			
Net loss resulting from early retirement and refinancing of debt	(23,668)	(1,958)	(6,776)
Bridge financing costs related to ICG	—	(49,490)	—
	(23,668)	(51,448)	(6,776)
Income (loss) before income taxes	(1,017,404)	135,251	177,108
Provision for (benefit from) income taxes	(333,717)	(7,589)	17,714
Net income (loss)	(683,687)	142,840	159,394
Less: Net income attributable to noncontrolling interest	(268)	(1,157)	(537)
Net income (loss) attributable to Arch Coal, Inc.	$ (683,955)	$ 141,683	$ 158,857
EARNINGS PER COMMON SHARE			
Basic earnings (loss) per common share	$ (3.24)	$ 0.75	$ 0.98
Diluted earnings (loss) per common share	$ (3.24)	$ 0.74	$ 0.97
Basic weighted average shares outstanding	211,381	190,086	162,398
Diluted weighted average shares outstanding	211,381	190,905	163,210
Dividends declared per common share	$ 0.20	$ 0.43	$ 0.39

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Net income (loss)	$ (683,687)	$ 142,840	$ 159,394
Other comprehensive income (loss), net of income taxes:			
Pension, postretirement and other post-employment benefits			
Unrealized gains (losses)	(14,523)	4,271	9,814
Net loss reclassified to income	918	1,665	101
	(13,605)	5,936	9,915
Available-for-sale securities			
Unrealized gains (losses)	(1,924)	114	1,841
Net loss reclassified to income	4	—	—
	(1,920)	114	1,841
Derivatives			
Unrealized gains	4,320	2,913	221
Net (gains) losses reclassified to income	2,653	(10,563)	1,514
	6,973	(7,650)	1,735
Total other comprehensive income (loss)	(8,552)	(1,600)	13,491
Total comprehensive income (loss)	$ (692,239)	$ 141,240	$ 172,885

The accompanying notes are an integral part of the condensed consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

	December 31 2012	December 31 2011
	(In thousands, except per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 784,622	$ 138,149
Restricted cash	3,453	10,322
Short term investments	234,305	—
Trade accounts receivable	247,539	380,595
Other receivables	84,541	88,584
Inventories	365,424	377,490
Prepaid royalties	11,416	21,944
Deferred income taxes	67,360	42,051
Coal derivative assets	22,975	13,335
Other	92,469	110,304
Total current assets	1,914,104	1,182,774
Property, plant and equipment:		
Coal lands and mineral rights	6,218,776	6,578,430
Plant and equipment	3,391,265	3,225,985
Deferred mine development	1,079,856	1,064,279
	10,689,897	10,868,694
Less accumulated depreciation, depletion and amortization	(3,352,799)	(2,919,544)
Property, plant and equipment, net	7,337,098	7,949,150
Other assets:		
Prepaid royalties	87,773	86,626
Goodwill	265,423	596,103
Equity investments	242,215	225,605
Other	160,164	173,701
Total other assets	755,575	1,082,035
Total assets	$ 10,006,777	$ 10,213,959
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 224,418	$ 383,782
Coal derivative liabilities	1,737	7,828
Accrued expenses and other current liabilities	318,018	348,207
Current maturities of debt and short-term borrowings	32,896	280,851
Total current liabilities	577,069	1,020,668
Long-term debt	5,085,879	3,762,297
Asset retirement obligations	409,705	446,784
Accrued pension benefits	67,630	48,244
Accrued postretirement benefits other than pension	45,086	42,309
Accrued workers' compensation	81,629	71,948
Deferred income taxes	664,182	976,753
Other noncurrent liabilities	221,030	255,382
Total liabilities	7,152,210	6,624,385
Redeemable noncontrolling interest	—	11,534
Stockholders' equity:		
Common stock, $0.01 par value, authorized 260,000 shares, issued 213,759 and 213,183 shares at December 31, 2012 and December 31, 2011, respectively	2,141	2,136
Paid-in capital	3,026,823	3,015,349
Treasury stock, 1,512 shares at December 31, 2012 and 2011, at cost	(53,848)	(53,848)
Retained earnings (accumulated deficit)	(104,042)	622,353
Accumulated other comprehensive loss	(16,507)	(7,950)
Total stockholders' equity	2,854,567	3,578,040
Total liabilities and stockholders' equity	$ 10,006,777	$ 10,213,959

The accompanying notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Three Years Ended December 31, 2012

	Common Stock	Paid-In Capital	Treasury Stock, at Cost	Retained Earnings	Accumulated Other Comprehensive Loss	Total
	(In thousands, except per share data)					
BALANCE AT JANUARY 1, 2010	$ 1,643	$ 1,721,230	$ (53,848)	$ 465,934	$ (19,853)	$ 2,115,106
Total comprehensive income				158,857	13,436	172,293
Dividends on common shares ($0.39 per share)				(63,373)		(63,373)
Issuance of 9 shares of common stock under the stock incentive plan — restricted stock and restricted stock units, net of forfeitures	0	0				—
Issuance of 155 shares of common stock under the stock incentive plan — stock options including income tax benefits	2	1,762				1,764
Employee stock-based compensation expense		11,717				11,717
BALANCE AT DECEMBER 31, 2010	1,645	1,734,709	(53,848)	561,418	(6,417)	2,237,507
Total comprehensive income (loss)				141,683	(1,533)	140,150
Dividends on common shares ($0.43 per share)				(80,748)		(80,748)
Issuance of 48,705 common shares	487	1,267,446				1,267,933
Issuance of 162 shares of common stock under the stock incentive plan — restricted stock and restricted stock units, net of forfeitures	2	(2)				—
Issuance of 199 shares of common stock under the stock incentive plan — stock options including income tax benefits	2	2,314				2,316
Employee stock-based compensation expense		10,882				10,882
BALANCE AT DECEMBER 31, 2011	2,136	3,015,349	(53,848)	622,353	(7,950)	3,578,040
Total comprehensive (loss)				(683,955)	(8,557)	(692,512)
Dividends on common shares ($0.20 per share)				(42,440)		(42,440)
Redemption of noncontrolling interest		(5,474)				(5,474)
Issuance of 49 shares of common stock under the stock incentive plan — restricted stock and restricted stock units, net of forfeitures	0	0				—
Issuance of 526 shares of common stock under the stock incentive plan — stock options including income tax benefits	5	5,126				5,131
Employee stock-based compensation expense		11,822				11,822
BALANCE AT DECEMBER 31, 2012	$ 2,141	$ 3,026,823	$ (53,848)	$ (104,042)	$ (16,507)	$ 2,854,567

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2012	2011	2010
		(In thousands)	
OPERATING ACTIVITIES			
Net income (loss)	$ (683,687)	$ 142,840	$ 159,394
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	525,508	466,587	365,066
Amortization of acquired sales contracts, net	(25,189)	(22,069)	35,606
Noncash mine closure and asset impairment costs	515,491	7,316	—
Goodwill and other intangible asset impairment	346,423	—	—
Bridge financing costs related to ICG	—	49,490	—
Amortization relating to financing activities	20,238	14,067	10,398
Net loss resulting from early retirement and refinancing of debt	23,668	1,958	6,776
Prepaid royalties expensed	22,650	34,842	34,605
Employee stock-based compensation expense	11,822	10,882	11,717
Gain on Knight Hawk transaction	—	—	(41,577)
Changes in operating assets and liabilities:			
Receivables	113,531	(74,914)	(7,287)
Inventories	9,468	(50,900)	5,160
Coal derivative assets and liabilities	(13,158)	6,079	9,554
Accounts payable, accrued expenses and other current liabilities	(171,580)	52,191	87,807
Income taxes, net	27,545	(21,759)	(1,364)
Deferred income taxes	(336,036)	10,519	(12,405)
Asset retirement obligations	(42,531)	3,868	23,997
Other	(11,359)	11,245	9,700
Cash provided by operating activities	332,804	642,242	697,147
INVESTING ACTIVITIES			
Acquisition of businesses, net of cash acquired	—	(2,894,339)	—
Capital expenditures	(395,225)	(540,936)	(314,657)
Additions to prepaid royalties	(13,269)	(29,957)	(27,355)
Proceeds from dispositions of property, plant and equipment	22,825	25,887	330
Purchases of short term investments	(236,862)	—	—
Proceeds from sales of short term investments	1,754	—	—
Investments in and advances to affiliates	(17,758)	(61,909)	(46,185)
Purchase of noncontrolling interest	(17,500)	—	—
Change in restricted cash	6,869	5,167	—
Consideration paid related to prior business acquisitions	—	(829)	(1,262)
Cash used in investing activities	(649,166)	(3,496,916)	(389,129)
FINANCING ACTIVITIES			
Proceeds from the issuance of senior notes	359,753	2,000,000	500,000
Proceeds from term note	1,633,500	—	—
Proceeds from the issuance of common stock, net	—	1,267,933	—
Payments to retire debt	(452,934)	(605,178)	(505,627)
Net increase (decrease) in borrowings under lines of credit and commercial paper program	(481,300)	424,396	(196,549)
Payments on term note	(7,625)	—	
Net payments on other debt	(682)	5,334	82
Debt financing costs	(50,568)	(114,823)	(12,751)
Dividends paid	(42,440)	(80,748)	(63,373)
Issuance of common stock under incentive plans	5,131	2,316	1,764
Contribution from noncontrolling interest	—	—	891
Cash provided by (used in) financing activities	962,835	2,899,230	(275,563)
Increase in cash and cash equivalents	646,473	44,556	32,455
Cash and cash equivalents, beginning of period	138,149	93,593	61,138
Cash and cash equivalents, end of period	$ 784,622	$ 138,149	$ 93,593
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid during the year for interest	$ 310,241	$ 213,697	$ 134,866
Cash refunded (paid) during the year for income taxes, net	$ 28,057	$ (7,094)	$ (36,765)

The accompanying notes are an integral part of the consolidated financial statements.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Arch Coal, Inc. and its subsidiaries and controlled entities (the "Company"). The Company's primary business is the production of thermal and metallurgical coal from surface and underground mines located throughout the United States, for sale to utility, industrial and export markets. On June 15, 2011, the Company acquired International Coal Group, Inc. ("ICG"). The Company currently operates 15 mining complexes in West Virginia, Kentucky, Maryland, Virginia, Illinois, Wyoming, Colorado and Utah. In addition, the Company has a metallurgical coal mine in development in West Virginia. All subsidiaries are wholly-owned. Intercompany transactions and accounts have been eliminated in consolidation.

The Company's subsidiary Arch Western Resources, LLC ("Arch Western") operates coal mines in Wyoming, Colorado and Utah. On April 9, 2012, Delta Housing, Inc., a subsidiary of BP p.l.c. and a joint venture partner in Arch Western, exercised their contractual right to require the Company to purchase their 0.5% common and their preferred membership interests in Arch Western. With the payment of the negotiated purchase amount of $17.5 million on July 2, 2012, Arch Western became a wholly-owned subsidiary.

Accounting Pronouncements

There are no accounting pronouncements whose adoption had, or is expected to have, a material impact on the Company's consolidated financial statements.

Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and revenues and expenses in the accompanying consolidated financial statements and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost. Cash equivalents consist of highly-liquid investments with an original maturity of three months or less when purchased. At December 31, 2012 and 2011, the carrying amounts of cash and cash equivalents approximate their fair value.

Allowance for Uncollectible Receivables

The Company establishes an allowance for uncollectible receivables for the amounts of trade accounts receivable and other receivables that are not expected to be collected, based on past collection history, the economic environment and specified risks identified in the receivables portfolio. Receivables are considered past due if the full payment is not received by the contractual due date. At December 31, 2012 and 2011, there was either no allowance or an insignificant allowance for uncollectible receivables.

Inventories

Coal and supplies inventories are valued at the lower of average cost or market. Coal inventory costs include labor, supplies, equipment costs, transportation costs incurred prior to the transfer of title to customers and operating overhead. The costs of removing overburden, called stripping costs, incurred during the production phase of the mine are considered variable production costs and are included in the cost of the coal extracted during the period the stripping costs are incurred.

Investments and Membership Interests in Joint Ventures

Investments and membership interests in joint ventures are accounted for under the equity method of accounting if the Company has the ability to exercise significant influence, but not control, over the entity. The Company's share of the entity's income or loss is reflected in other operating income, net in the consolidated statements of operations. Information about investment activity is provided in Note 8, "Equity Investments and Membership Interests in Joint Ventures."

Marketable equity and debt securities held by the Company that do not qualify for equity method accounting are classified as available-for-sale and are recorded at their fair value on the balance sheet. Unrealized gains and losses on these investments are recorded in other comprehensive income or loss. A decline in the value of an investment that is considered other-than-temporary would be recognized in operating expenses.

Prepaid Royalties

Leased mineral rights are often acquired through royalty payments. When royalty payments represent prepayments recoupable against future production, they are recorded as a prepaid asset, with amounts expected to be recouped within one year classified as current. When the coal is mined under these leases the royalties are recouped and the prepayment is charged to cost of sales.

Acquired Sales Contracts

Coal supply agreements (sales contracts) acquired in a business combination are capitalized at their fair value and amortized over the tons of coal shipped during the term of the contract. The fair value of a sales contract is determined by discounting the cash flows attributable to the difference between the contract price and the prevailing forward prices for the tons under contract at the date of acquisition. See Note 4, "Acquired Sales Contracts" for further information related to the Company's acquired sales contracts.

Exploration Costs

Costs to acquire permits for exploration activities are capitalized. Drilling and other costs related to locating coal deposits and evaluating the economic viability of such deposits are expensed as incurred.

Property, Plant and Equipment

Plant and Equipment

Plant and equipment are recorded at cost. Interest costs incurred during the construction period for major asset additions are capitalized. We capitalized $15.6 million of interests costs during the year ended December 31, 2012, while the amounts capitalized in the years ended December 31, 2011 and 2010 were insignificant. Expenditures that extend the useful lives of existing plant and equipment or increase the productivity of the asset are capitalized. The cost of maintenance and repairs that do not extend the useful life or increase the productivity of the asset are expensed as incurred.

Preparation plants and loadouts are depreciated using the units-of-production method over the estimated recoverable reserves, subject to a minimum level of depreciation. Other plant and equipment are depreciated principally using the straight-line method over the estimated useful lives of the assets, limited by the remaining life

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

of the mine. The useful lives of mining equipment, including longwalls, draglines and shovels, range from 5 to 32 years. The useful lives of buildings and leasehold improvements generally range from 10 to 30 years.

Deferred Mine Development

Costs of developing new mines or significantly expanding the capacity of existing mines are capitalized and amortized using the units-of-production method over the estimated recoverable reserves that are associated with the property being benefited. Costs may include construction permits and licenses; mine design; construction of access roads, shafts, slopes and main entries; and removing overburden to access reserves in a new pit. Additionally, deferred mine development includes the asset cost associated with asset retirement obligations.

Coal Lands and Mineral Rights

Rights to coal reserves may be acquired directly through governmental or private entities. A significant portion of the Company's coal reserves are controlled through leasing arrangements. Lease agreements are generally long-term in nature (original terms range from 10 to 50 years), and substantially all of the leases contain provisions that allow for automatic extension of the lease term providing certain requirements are met.

The net book value of the Company's coal interests was $5.1 billion and $5.6 billion at December 31, 2012 and 2011. Payments to acquire royalty lease agreements and lease bonus payments are capitalized as a cost of the underlying mineral reserves and depleted over the life of proven and probable reserves. Coal lease rights are depleted using the units-of-production method, and the rights are assumed to have no residual value.

Future lease bonus payments total $83.4 million in 2013, $67.3 million in 2014, $60.0 million in 2015, and $60.0 million in 2016.

Depreciation, depletion and amortization.

The depreciation, depletion and amortization related to long-lived assets is reflected in the statement of operations as a separate line item. No depreciation, depletion or amortization is included in any other operating cost categories.

Impairment

If facts and circumstances suggest that the carrying value of a long-lived asset or asset group may not be recoverable, the asset or asset group is reviewed for potential impairment. If this review indicates that the carrying amount of the asset will not be recoverable through projected undiscounted cash flows generated by the asset and its related asset group over its remaining life, then an impairment loss is recognized by reducing the carrying value of the asset to its fair value. The Company may, under certain circumstances, idle mining operations in response to market conditions or other factors. Because an idling is not a permanent closure, it is not considered an automatic indicator of impairment.

Goodwill

In a business combination, goodwill represents the excess of the purchase price over the fair value assigned to the net tangible and identifiable intangible assets acquired. The Company tests goodwill for impairment annually as of the beginning of the fourth quarter, or when circumstances indicate a possible impairment may exist. If the results of the testing indicate that the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the fair value of goodwill must be calculated. An impairment loss generally would be recognized when the carrying amount of goodwill exceeds the implied fair value of goodwill, determined by subtracting the fair value of

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

the other assets and liabilities associated with the reporting unit from the total fair value of the reporting unit. The fair value of a reporting unit is determined using a discounted cash flow ("DCF") technique. A number of significant assumptions and estimates are involved in the application of the DCF analysis to forecast operating cash flows, including the discount rate and projections of selling prices and costs to produce. See additional discussion in Note 7, "Goodwill."

Deferred Financing Costs

The Company capitalizes costs incurred in connection with new borrowings, the establishment or enhancement of credit facilities and the issuance of debt securities. These costs are amortized as an adjustment to interest expense over the life of the borrowing or term of the credit facility using the interest method. The unamortized balance of deferred financing costs was $101.5 million and $90.5 million at December 31, 2012 and 2011, respectively. Amounts classified as current were $17.3 million and $15.8 million at December 31, 2012 and 2011, respectively. Current amounts are recorded in other current assets and noncurrent amounts are recorded in other assets in the accompanying consolidated balance sheets.

Revenue Recognition

Revenues include sales to customers of coal produced at Company operations and coal purchased from third parties. The Company recognizes revenue at the time risk of loss passes to the customer at contracted amounts. Transportation costs are included in cost of sales and amounts billed by the Company to its customers for transportation are included in revenues.

Other Operating Income, Net

Other operating income, net in the accompanying consolidated statements of operations reflects income and expense from sources other than physical coal sales, including: bookouts, the practice of offsetting purchase and sale contracts for shipping convenience purposes, and contract settlements; royalties earned from properties leased to third parties; income from equity investments; gains and losses from dispositions of assets; and realized gains and losses on heating oil derivatives that do not qualify for hedge accounting and are not held for trading purposes.

Asset Retirement Obligations

The Company's legal obligations associated with the retirement of long-lived assets are recognized at fair value at the time the obligations are incurred. Accretion expense is recognized through the expected settlement date of the obligation. Obligations are incurred at the time development of a mine commences for underground and surface mines or construction begins for support facilities, refuse areas and slurry ponds. The obligation's fair value is determined using a DCF technique and is based upon permit requirements and various estimates and assumptions that would be used by market participants, including estimates of disturbed acreage, reclamation costs and assumptions regarding equipment productivity. Upon initial recognition of a liability, a corresponding amount is capitalized as part of the carrying value of the related long-lived asset.

The Company reviews its asset retirement obligation at least annually and makes necessary adjustments for permit changes as granted by state authorities and for revisions of estimates of the amount and timing of costs. For ongoing operations, adjustments to the liability result in an adjustment to the corresponding asset. For idle operations, adjustments to the liability are recognized as income or expense in the period the adjustment is recorded. Any difference between the recorded obligation and the actual cost of reclamation is recorded in profit or loss in the period the obligation is settled. See additional discussion in Note 14, "Asset Retirement Obligations."

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Derivative Instruments

The Company generally utilizes derivative instruments to manage exposures to commodity prices. Additionally, the Company may hold certain coal derivative instruments for trading purposes. Derivative financial instruments are recognized in the balance sheet at fair value. Certain coal contracts may meet the definition of a derivative instrument, but because they provide for the physical purchase or sale of coal in quantities expected to be used or sold by the Company over a reasonable period in the normal course of business, they are not recognized on the balance sheet.

Certain derivative instruments are designated as the hedge instrument in a hedging relationship. In a fair value hedge, the Company hedges the risk of changes in the fair value of a firm commitment, typically a fixed-price coal sales contract. Changes in both the hedged firm commitment and the fair value of a derivative used as a hedge instrument in a fair value hedge are recorded in earnings. In a cash flow hedge, the Company hedges the risk of changes in future cash flows related to a forecasted purchase or sale. Changes in the fair value of the derivative instrument used as a hedge instrument in a cash flow hedge are recorded in other comprehensive income or loss. Amounts in other comprehensive income or loss are reclassified to earnings when the hedged transaction affects earnings and are classified in a manner consistent with the transaction being hedged. The Company formally documents the relationships between hedging instruments and the respective hedged items, as well as its risk management objectives for hedge transactions.

The Company evaluates the effectiveness of its hedging relationships both at the hedge's inception and on an ongoing basis. Any ineffective portion of the change in fair value of a derivative instrument used as a hedge instrument in a fair value or cash flow hedge is recognized immediately in earnings. The ineffective portion is based on the extent to which exact offset is not achieved between the change in fair value of the hedge instrument and the cumulative change in expected future cash flows on the hedged transaction from inception of the hedge in a cash flow hedge or the change in the fair value. Ineffectiveness was insignificant for the years ended December 31, 2012, 2011 and 2010. See Note 9, "Derivatives" for further disclosures related to the Company's derivative instruments.

Fair Value

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly hypothetical transaction between market participants at a given measurement date. Valuation techniques used must maximize the use of observable inputs and minimize the use of unobservable inputs. See Note 11, "Fair Values Measurements" for further disclosures related to the Company's recurring fair value estimates.

Income Taxes

Deferred income taxes are provided for temporary differences arising from differences between the financial statement amount and tax basis of assets and liabilities existing at each balance sheet date using enacted tax rates anticipated to be in effect when the related taxes are expected to be paid or recovered. A valuation allowance is established if it is more likely than not that a deferred tax asset will not be realized. In determining the need for a valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies and the reversal of temporary differences.

The benefit from tax positions that are uncertain is not recognized unless the Company concludes that it is more likely than not that the position would sustain in a dispute with taxing authorities, should the dispute be taken to the court of last resort. The Company would measure any such benefit at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement with taxing authorities.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

See Note 13, "Taxes" for further disclosures about income taxes.

Benefit Plans

The Company has non-contributory defined benefit pension plans covering most of its salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The Company also currently provides certain postretirement medical and life insurance coverage for eligible employees. The cost of providing these benefits are determined on an actuarial basis and accrued over the employee's period of active service.

The Company recognizes the overfunded or underfunded status of these plans as determined on an actuarial basis on the balance sheet and the changes in the funded status are recognized in other comprehensive income. See Note 18, "Employee Benefit Plans" for additional disclosures relating to these obligations.

Stock-Based Compensation

The compensation cost of all stock-based awards is determined based on the grant-date fair value of the award, and is recognized over the requisite service period. The grant-date fair value of option awards is determined using a Black-Scholes option pricing model. Compensation cost for an award with performance conditions is accrued if it is probable that the conditions will be met. See further discussion in Note 16, "Stock Based Compensation and Other Incentive Plans."

2. Debt and Financing Arrangements

	December 31, 2012	December 31, 2011
	(In thousands)	
Indebtedness to banks under credit facilities	$ —	$ 481,300
Term loan ($1.65 billion face value) due 2018	1,627,384	—
6.75% senior notes ($450.0 million face value) due 2013	—	450,971
8.75% senior notes ($600.0 million face value) due 2016	590,999	588,974
7.00% senior notes due 2019 at par	1,000,000	1,000,000
9.875% senior notes ($375.0 million face value) due 2019	360,042	—
7.25% senior notes due 2020 at par	500,000	500,000
7.25% senior notes due 2021 at par	1,000,000	1,000,000
Other	40,350	21,903
	5,118,775	4,043,148
Less current maturities of debt and short-term borrowings	32,896	280,851
Long-term debt	$ 5,085,879	$ 3,762,297

The current maturities of debt include contractual maturities and amounts borrowed under our revolving credit facility and accounts receivable securitization program that the Company does not intend to refinance on a long-term basis, based on cash projections and management's plans.

On May 16, 2012, the Company entered into an amendment to its senior secured revolving credit facility that amended certain financial maintenance covenants, suspending the Company's compliance with the debt-to-EBITDA ratio, easing other financial covenants through September 2014 and adding defined minimum EBITDA targets. The maximum borrowing capacity of the revolving credit facility was reduced from $2 billion to $600 million. In conjunction with the amendment, the Company borrowed $1.4 billion under a six-year secured term loan facility, issued at a 1% discount. The term loan contains no financial maintenance covenants, is prepayable and is secured by the same assets as borrowings under the revolving credit facility. The amendment reduced the quarterly dividend the Company may pay on its common stock to $0.03 per share. Quarterly principal payments of $3.5 million began in September 2012, plus interest at a rate of the greater of a LIBOR-based rate or 1.25%, plus 450 basis points. The proceeds of the term loan were used to retire all outstanding borrowings under the revolving credit facility and the outstanding $450.0 million principal amount of 6.75% Senior Notes due 2013 issued by Arch Western Finance, LLC ("Arch Western Finance"), the Company's indirect subsidiary.

On May 16, 2012, Arch Western Finance accepted for purchase an aggregate of approximately $304.0 million principal amount of its 6.75% Senior Notes due 2013 in an initial settlement pursuant to the terms of its tender offer and consent solicitation, which commenced on May 1, 2012, and called for redemption all of the remaining notes outstanding after the completion of the tender offer. The consideration for each $1,000 of principal purchased under the tender offer and consent solicitation was $1,002.50, for a total purchase consideration of $304.8 million. On May 30, 2012, the remaining notes with an outstanding principal amount of $146.0 million were redeemed at par value.

On November 21, 2012, the Company issued $375.0 million aggregate principal amount of 9.875% senior unsecured notes due 2019 (the "9.875% Notes") at an issue price of 95.934% of the face amount. Also on November 21, 2012, the Company borrowed an incremental $250.0 million on the term loan facility at a 1% discount at the same rate as the initial borrowing discussed previously. The principal payments on the loan increased to $4.125 million per quarter as a result of the incremental borrowing. Under the terms of the credit agreement, the incremental term loan reduced the size of Arch's revolving credit facility to $350 million from $600 million.

At the same time, the Company amended its senior secured revolving credit facility to relax financial maintenance covenants and eliminate the minimum EBITDA targets until December 31, 2015.

The Company wrote off $23.4 million of deferred financing costs relating to the reduction in capacity of the senior secured revolving credit facility and $1.1 million related to the redemption of the 6.75% Senior Notes due 2013, offset by $(0.8) million of unamortized issue premium on the notes. The write-off of deferred financing fees, along with other transaction fees associated with these transactions, is reflected in "Loss on extinguishment and refinancing of debt" in the consolidated statements of operations.

The Company paid financing costs of $50.6 million, $114.8 million and $12.8 million in conjunction with its financing activities during the years ended December 31, 2012, 2011 and 2010, respectively. The Company's financing fees are generally deferred, however, the Company incurred a fee of $49.5 million in 2011 in conjunction with the acquisition of ICG that was expensed, as the related bridge financing facility was not used.

Credit Facilities

Borrowings under the Company's senior secured revolving credit facility bear interest at a floating rate based on LIBOR determined by reference to the Company's leverage ratio, as calculated in accordance with the underlying credit agreement. The credit facility has a five-year term that expires on June 14, 2016 and is secured by substantially all of the Company's assets as well as its ownership interests in substantially all of its subsidiaries. Commitment fees of 0.50% to 0.75% per annum are payable on the average unused daily balance of the revolving credit facility.

The Company maintains an accounts receivable securitization program under which eligible trade receivables are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit. The entity through which these receivables are sold is consolidated into the Company's financial statements. The Company may borrow and draw letters of credit against the facility, and pays facility fees, program fees and letter of credit fees (based on amounts of outstanding letters of credit). The total aggregate borrowings and letters of credit are limited by eligible accounts

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

receivable, as defined under the terms of the agreement. The credit facility supporting the borrowings under the program is subject to renewal annually, and expires on December 10, 2013.

Financial covenant requirements may restrict the amount of unused capacity available to the Company for borrowings and letters of credit.

On June 14, 2011, the Company terminated its commercial paper placement program and the supporting credit facility.

Since May, when borrowings under the revolving credit facility were retired with the proceeds of the term loan, we have borrowed only under the accounts receivable securitization program. At December 31, 2012, the available borrowing capacity under our lines of credit with financial institutions was approximately $333 million.

2016 Senior Notes

The Company has outstanding $600.0 million in aggregate principal amount of 8.75% senior unsecured notes due 2016 ("2016 Notes"). The 2016 Notes were issued at an initial issue price of 97.464% of the face amount. Interest is payable on the notes on February 1 and August 1 of each year. At any time on or after August 1, 2013, the Company may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.375% for notes redeemed between August 1, 2013 and July 31, 2014; 102.188% for notes redeemed between August 1, 2014 and July 31, 2015; and 100% for notes redeemed on or after August 1, 2015.

2020 Senior Notes

On August 9, 2010, the Company issued $500.0 million in aggregate principal amount of 7.25% senior unsecured notes due in 2020 ("2020 Notes") at par. Interest is payable on the 2020 Notes on April 1 and October 1 of each year. At any time on or after October 1, 2015, the Company may redeem some or all of the notes. The redemption price reflected as a percentage of the principal amount is: 103.625% for notes redeemed between October 1, 2015 and September 30, 2016; 102.417% for notes redeemed between October 1, 2016 and September 30, 2017; 101.208% for notes redeemed between October 1, 2017 and September 30, 2018; and 100% for notes redeemed on or after October 1, 2018. In addition, at any time and on one or more occasions prior to October 1, 2013, the Company may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 107.250%.

2019 and 2021 Senior Notes

On June 14, 2011, the Company issued $1.0 billion of 7.00% unsecured senior notes due 2019 ("2019 Notes") and $1.0 billion of 7.25% unsecured senior notes due 2021 ("2021 Notes") at their face amount. These notes were used to finance, along with an issuance of common stock discussed in Note 15, "Capital Stock", the acquisition of ICG. Interest is payable on the 2019 Notes and 2021 Notes on June 15 and December 15 of each year.

At any time prior to June 15, 2014, the Company may redeem up to 35% of the original aggregate principal amount of each of the 2019 Notes and 2021 Notes, plus accrued and unpaid interest, with the net proceeds from certain equity offerings, at a redemption price, reflected as a percentage of the principal amount, equal to 107.0% and 107.25%, respectively. The Company may redeem the 2019 Notes prior to June 15, 2015 and the 2021 Notes prior to June 15, 2016 at the respective make-whole prices set forth in the indenture. On or after June 15, 2015, the Company may redeem the 2019 Notes at redemption prices, reflected as a percentage of the principal amount, of: 103.5% from June 15, 2015 through June 14, 2016; 101.75% from June 15, 2016 through June 14, 2017;

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and 100% beginning on June 15, 2017. On or after June 15, 2016, the Company may redeem the 2021 Notes at redemption prices, reflected as a percentage of the principal amount, of: 103.625% from June 15, 2016 through June 14, 2017; 102.417% from June 15, 2017 through June 14, 2018; 101.208% from June 15, 2018 through June 14, 2019 and 100% beginning on June 15, 2019. In each case, accrued and unpaid interest at the redemption date is due upon redemption.

9.875% Notes

Interest is payable on the 9.875% Notes annually on June 15 and December 15, beginning on June 15, 2013. At any time on or after December 15, 2016, the Company may redeem some or all of the notes. The redemption price, reflected as a percentage of the principal amount, is: 104.938% for notes redeemed between December 15, 2016 and December 14, 2017; 102.469% for notes redeemed between December 15, 2017 and December 14, 2018; and 100% for notes redeemed on or after December 15, 2018. In addition, at any time and on one or more occasions prior to December 15, 2015, the Company may redeem an aggregate principal amount of senior notes not to exceed 35% of the original aggregate principal amount of the senior notes outstanding with the proceeds of one or more public equity offerings, at a redemption price equal to 109.875%.

The unsecured senior notes are guaranteed by substantially all of the Company's subsidiaries, except for Arch Receivable Company, LLC, which is the conduit for the accounts receivable securitization program, and the Company's subsidiaries outside the U.S.

Debt Retirements

Upon the closing of the ICG acquisition, the Company gave a 30-day redemption notice to the Trustee of ICG's 9.125% senior notes and legally discharged its obligation under the 9.125% senior notes by depositing the required funds with the Trustee to redeem the debt. On July 14, 2011, all of the outstanding 9.125% senior notes were redeemed at an aggregate price of $251.4 million, including the required make-whole premium, plus accrued interest of $5.2 million.

At the acquisition date, ICG's 4.00% convertible senior notes with a fair value of $298.5 million and 9.00% convertible senior notes with a fair value of $1.7 million ("convertible notes") became convertible into cash, pursuant to the amended indentures governing the convertible notes, at a calculated conversion rate of $2,614.6848 for each $1,000 in principal amount surrendered for conversion for the 4.00% convertible notes and $2,392.73414 for the 9.00% convertible notes for conversions occurring prior to August 17, 2011.

At the acquisition date, other ICG debt had a fair value of approximately $54.0 million and consisted mainly of equipment notes and insurance notes payable.

The Company recognized a net loss of $2.0 million during the year ended December 31, 2011 on the early extinguishment of ICG's debt, including the conversions of the 4.00% and 9.00% convertible notes described above. Any remaining amounts outstanding under the convertible notes and other ICG debt is included in "other" in the debt table above.

The Company redeemed $500.0 million aggregate principal amount of the 6.75% Senior Notes due 2013 on September 8, 2010. The Company recognized a loss on the redemption of $6.8 million, including the payment of the $5.6 million redemption premium and the write-off of $3.3 million of unamortized debt financing costs, partially offset by the write-off of $2.1 million of the original issue premium.

Debt Maturities

Expected aggregate maturities of debt for the next five years are $34.7 million in 2013, $20.6 million in 2014, $20.8 million in 2015, $620.9 million in 2016 and $21.1 million in 2017.

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Terms of the Company's credit facilities and leases contain financial and other covenants that limit the ability of the Company to, among other things, acquire, dispose, merge or consolidate assets; incur additional debt; pay dividends and make distributions or repurchase stock; make investments; create liens; issue and sell capital stock of subsidiaries; enter into restrictions affecting the ability of restricted subsidiaries to make distributions, loans or advances to the Company; engage in transactions with affiliates and enter into sale and leaseback transactions. In addition, the covenants require the Company to pledge assets to collateralize the revolving credit and term loan facilities. The assets pledged include equity interests in wholly-owned subsidiaries, certain real property interests, accounts receivable and inventory of the Company. Failure by the Company to comply with such covenants could result in an event of default, which, if not cured or waived, could have a material adverse effect on the Company.

3. Mine Closure and Asset Impairment Costs

In response to decreasing demand for thermal coal, the Company made the decision in the second quarter of 2012 to close four thermal coal mining complexes and to temporarily idle a fifth complex, all acquired with ICG. The company also curtailed production at other Appalachia mines. These actions resulted in a total workforce reduction of approximately 750 positions. The Company will incur customary annual maintenance costs related to these properties in the future. The terms of customer contracts will be fulfilled by other operations.

The following costs are reflected in the line "Mine closure and asset impairment costs" on the consolidated statements of operations for the year ended December 31, 2012:

Parts and supplies inventory writedown	$ 2,598
Impairment of property, plant and equipment	95,641
Impairment of coal properties and deferred development costs	403,279
Royalty obligations	11,546
Employee termination benefits	12,274
Pension, postretirement and occupational disease curtailment gain, net (see notes 17 and 18)	(1,770)
	$ 523,568

The Company determined that assets of the closed operations with a net book value of $51 million could be redeployed to other operations. The remainder of the assets were determined to be completely impaired, based on an analysis of the marketability of thermal coal properties in the current market environment.

The majority of the employee termination benefits were paid in the third quarter of 2012. The royalty obligations represent minimum payments on various leases and will be paid over the remaining term of the leases, through 2016.

The $7.3 million in asset impairment costs for the year ended December 31, 2011 related to a preparation plant and loadout of an acquired ICG mining operation that would not be used in ongoing operations.

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Notes to Consolidated Financial Statements (Continued)

4. Acquired Sales Contracts

The acquired sales contracts reflected in the consolidated balance sheets are as follows:

	December 31, 2012		December 31, 2011	
	Assets	Liabilities	Assets	Liabilities
	(In thousands)		(In thousands)	
Acquired fair value	$ 131,819	$ 166,697	$ 149,457	$ 166,697
Accumulated amortization	(123,776)	(105,237)	(115,322)	(69,699)
Total	$ 8,043	$ 61,460	$ 34,135	$ 96,998
Net total		$ (53,417)		$ (62,863)
Balance Sheet classification:				
Other current	$ 5,651	$ 14,038	$ 18,929	$ 38,441
Other noncurrent	$ 2,392	$ 47,422	$ 15,206	$ 58,557

In 2012 the Company recognized an impairment loss of $15.7 million to write off a contract acquired with the ICG acquisition with an original acquired fair value of $17.5 million.

The Company anticipates amortization of acquired sales contracts, based upon expected shipments in the next five years, to be income of approximately $8.1 million in 2013, $11.6 million in 2014, $10.8 million in 2015, $9.3 million in 2016 and $3.2 million in 2017.

5. Accumulated Other Comprehensive Income (Loss)

Other comprehensive income (loss) includes transactions recorded in stockholders' equity during the year, excluding net income and transactions with stockholders. Following are the items included in accumulated other comprehensive income (loss):

	Derivative Instruments	Pension, Postretirement and Other Post-Employment Benefits	Available-for-Sale Securities	Accumulated Other Comprehensive Loss
	(In thousands)			
Balance at January 1, 2010	$ 1,186	$ (20,539)	$ (500)	$ (19,853)
2010 activity, before tax	2,711	15,406	2,877	20,994
2010 activity, tax effect	(976)	(5,546)	(1,036)	(7,558)
Balance at December 31, 2010	2,921	(10,679)	1,341	(6,417)
2011 activity, before tax	(11,951)	9,345	176	(2,430)
2011 activity, tax effect	4,301	(3,342)	(62)	897
Balance at December 31, 2011	(4,729)	(4,676)	1,455	(7,950)
2012 activity, before tax	10,895	(21,265)	(3,000)	(13,370)
2012 activity, tax effect	(3,922)	7,655	1,080	4,813
Balance at December 31, 2012	$ 2,244	$ (18,286)	$ (465)	$ (16,507)

6. Investments in Available-for-Sale Securities

The Company has invested in marketable debt securities, primarily highly liquid AA—rated corporate bonds, U.S. government and government agency securities. These investments are held in the custody of a major financial institution. These securities, along with the Company's investments in marketable equity securities, are classified as

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Notes to Consolidated Financial Statements (Continued)

available-for-sale securities and, accordingly, the unrealized gains and losses are recorded through other comprehensive income.

The Company's investments in available-for-sale marketable securities are as follows:

	December 31, 2012					
					Balance Sheet Classification	
	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Short-Term Investments	Other Assets
	(In thousands)					
Available-for-sale:						
U.S. government and agency securities	$ 146,993	$ 2	$ (412)	$ 146,583	$ 146,583	$ —
Corporate notes and bonds	88,118	—	(396)	87,722	87,722	—
Equity securities	5,271	2,704	(2,628)	5,347	—	5,347
Total Investments	$ 240,382	$ 2,706	$ (3,436)	$ 239,652	$ 234,305	$ 5,347

The aggregate fair value of investments with unrealized losses was $223.3 million at December 31, 2012.

	December 31, 2011					
					Balance Sheet Classification	
	Cost Basis	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Short-Term Investments	Other Assets
	(In thousands)					
Available-for-sale:						
Equity securities	$ 5,268	$ 4,394	$ (2,122)	$ 7,540	$ —	$ 7,540
Total Investments	$ 5,268	$ 4,394	$ (2,122)	$ 7,540	$ —	$ 7,540

The debt securities outstanding at December 31, 2012 have maturity dates ranging from the first quarter of 2013 through the second quarter of 2014. The Company classifies its investments as current based on the nature of the investments and their availability for use in current operations.

7. Goodwill

Changes in the carrying value of goodwill for the years ended December 31, 2012, 2011 and 2010 are as follows:

	(In thousands)
Balance at January 1, 2010	$ 113,701
Consideration paid related to prior business acquisitions	1,262
Balance at December 31, 2010	114,963
Consideration paid related to prior business acquisitions	829
Acquisition of ICG	480,311
Balance at December 31, 2011	596,103
Impairment	(330,680)
Balance at December 31, 2012	$ 265,423

During the second quarter of 2012, a significant drop in the Company's stock price, combined with continuing weak demand for thermal coal during the quarter and the Company's resulting production cuts, indicated that the fair value of the Company's goodwill could be less than its carrying value. Accordingly, the Company performed the

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Notes to Consolidated Financial Statements (Continued)

first step of the two-step goodwill impairment test as of June 30, 2012. The value of the Company's Black Thunder reporting unit in the Powder River Basin, where $115.8 million of goodwill had been allocated, is sensitive to market demand for thermal coal. The further weakening in thermal coal markets had significantly impacted the projected demand for and pricing of coal produced at Black Thunder. In step one of the goodwill impairment testing, the fair value of the Black Thunder reporting unit did not exceed its carrying value, primarily due to the impact of lower demand on near term sales volumes and pricing. Based on initial estimates of the fair values of the assets and liabilities and the deficit of the fair value when compared to the related book values, the Company recorded a preliminary impairment charge for the entire $115.8 million carrying value of Black Thunder's goodwill during the second quarter of 2012. We subsequently performed a valuation of Black Thunder's assets and liabilities to determine the fair value of the reporting unit's goodwill, which supported the estimation that the goodwill allocated to the Black Thunder reporting unit had no value.

The goodwill amounts allocated to certain reporting units in the Company's Appalachia segment acquired with the ICG acquisition are sensitive to volatility in the demand for metallurgical coal. During the 2012, metallurgical prices fell substantially from the peaks reached during 2011, when the reporting units were acquired with the Company's purchase of ICG. This caused the fair value of two of these reporting units to fall below their carrying value. The allocated goodwill of $214.9 million for those reporting units was determined to be fully impaired, based on the discounted cash flows used in the ICG acquisition valuation, adjusted for current market conditions and estimates of production levels. The Company recognized the impairment charge in the fourth quarter of 2012.

8. Equity Investments and Membership Interests in Joint Ventures

Below are the equity method investments reflected in the consolidated balance sheets:

	Knight Hawk	DKRW	DTA	Tenaska	Millennium	Tongue River	Total
				(In thousands)			
Balance at January 1, 2010	$ 49,603	$ 23,589	$ 14,076	$ —	$ —	$ —	$ 87,268
Investments in affiliates	77,637	—	—	9,768	—	—	87,405
Advances to (distributions from) affiliates, net	(12,639)	—	4,264	—	—	—	(8,375)
Equity in comprehensive income (loss)	16,649	(1,628)	(3,868)	—	—	—	11,153
Balance at December 31, 2010	$ 131,250	$ 21,961	$ 14,472	$ 9,768	$ —	$ —	$ 177,451
Investments in affiliates	—	—	—	5,500	25,000	12,989	43,489
Advances to (distributions from) affiliates, net	(16,621)	—	6,498	—	3,477	—	(6,646)
Equity in comprehensive income (loss)	20,596	(2,246)	(4,884)	(2)	(2,153)	—	11,311
Balance at December 31, 2011	$ 135,225	$ 19,715	$ 16,086	$ 15,266	$ 26,324	$ 12,989	$ 225,605
Investments in affiliates	—	—	—	—	—	—	—
Advances to (distributions from) affiliates, net	(7,151)	—	4,335	—	8,798	1,708	7,690
Equity in comprehensive income (loss)	20,989	(4,200)	(4,959)	(2)	(2,908)	—	8,920
Balance at December 31, 2012	$ 149,063	$ 15,515	$ 15,462	$ 15,264	$ 32,214	$ 14,697	$ 242,215
Notes receivable from investees:							
Balance at December 31, 2011	$ —	$ 30,751	$ —	$ 5,059	$ —	$ —	$ 35,810
Balance at December 31, 2012	$ —	$ 38,680	$ —	$ 5,148	$ —	$ —	$ 43,828

The Company holds an equity interest in Knight Hawk Holdings, LLC ("Knight Hawk"), a coal producer in the Illinois Basin. In June 2010, the Company exchanged 68.4 million tons of coal reserves in the Illinois Basin for an additional 9% ownership interest, increasing the Company's ownership in Knight Hawk to 42% from 33.33%. The Company recognized a gain of $41.6 million on the transaction, representing the difference between the fair value and the $12.1 million net book value of the coal reserves, adjusted for the Company's retained ownership interest in the reserves through its investment in Knight Hawk. In December 2010, the Company increased its ownership interest in Knight Hawk to 49% for $26.6 million in cash.

The Company holds a 24% equity interest in DKRW Advanced Fuels LLC ("DKRW"), a company engaged in developing coal-to-liquids facilities. DKRW may borrow funds from the Company under a convertible secured promissory note. Amounts borrowed are due and payable in cash or in additional equity interests on the earlier of June 30, 2013 or upon the closing of DKRW's next financing, bear interest at the rate of 15% per annum, and are secured by DKRW's equity interests in Medicine Bow Fuel & Power LLC. The note balances above are reflected in other receivables on the consolidated balance sheets.

The Company holds a general partnership interest of 21.875% in Dominion Terminal Associates ("DTA"), which is accounted for under the equity method. DTA operates a ground storage-to-vessel coal transloading facility in Newport News, Virginia for use by the partners. Under the terms of a throughput and handling agreement with DTA, each partner is charged its share of cash operating and debt-service costs in exchange for the right to use the facility's loading capacity and is required to make periodic cash advances to DTA to fund such costs.

The Company holds a 35% ownership interest in Tenaska Trailblazer Partners, LLC ("Tenaska"), the developer of the Trailblazer Energy Center, a fossil-fuel-based electric power plant near Sweetwater, Texas. The plant, fueled by low sulfur coal, will capture and store carbon dioxide for enhanced oil recovery applications. Additional future payments are due upon the achievement of project milestones to maintain the Company's interest. The Company made a milestone payment of $5.5 million in 2011. The Company will also pay 35% of the future development costs of the project, not to exceed $12.5 million without prior approval from the Company. The receivables for these development costs, shown above, are reflected in the consolidated balance sheets in other noncurrent assets, as the development costs will either be reimbursed when the project receives construction financing, or they will be considered an additional capital contribution, with ownership percentages adjusted accordingly.

In January 2011, the Company purchased a 38% ownership interest in Millennium Bulk Terminals-Longview, LLC ("Millennium"), the owner of a brownfield bulk commodity terminal on the Columbia River near Longview, Washington, for $25.0 million, plus additional future consideration upon the completion of certain project milestones. Millennium continues to work on obtaining the required approvals and necessary permits to complete dredging and other upgrades to enable coal, alumina and cementitious material shipments through the terminal. The Company will control 38% of the terminal's throughput and storage capacity, in order to facilitate export shipments of coal off the west coast of the United States.

In July 2011, the Company purchased a 35% membership interest in the Tongue River Holding Company, LLC ("Tongue River") joint venture. Tongue River will develop and construct a railway line near Miles City, Montana and the Company's Otter Creek reserves. The Company has the right, upon the receipt of permits and approval for construction or under other prescribed circumstances, to require the other investors to purchase all of the Company's units in the venture at an amount equal to the capital contributions made by the Company at that time, less any distributions received.

The Company may be required to make future contingent payments of up to $72.9 million related to development financing for certain of its equity investees. The Company's obligation to make these payments, as well as the timing of any payments required, is contingent upon a number of factors, including project development progress, receipt of permits and construction financing.

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Summarized financial information of the Company's equity method investees follows:

	December 31 2012	2011 (In thousands)	2010
Condensed combined income statement information:			
Revenues	$ 190,661	$ 184,358	$ 172,933
Gross profit	15,308	19,495	25,203
Income from operations	8,898	13,180	20,243
Net income	641	6,788	16,015
Condensed combined balance sheet information:			
Current assets	$ 78,961	$ 94,644	
Noncurrent assets	387,884	331,848	
Total assets	$ 466,845	$ 426,492	
Current liabilities	$ 57,403	$ 51,674	
Noncurrent liabilities	128,489	120,494	
Equity	280,690	254,163	
Noncontrolling interest	263	161	
Total liabilities and equity	$ 466,845	$ 426,492	

9. Derivatives

Diesel fuel price risk management

The Company is exposed to price risk with respect to diesel fuel purchased for use in its operations. The Company anticipates purchasing approximately 57 to 67 million gallons of diesel fuel for use in its operations during 2013. To protect the Company's cash flows from increases in the price of diesel fuel for its operations, the Company uses forward physical diesel purchase contracts and purchased heating oil call options, and in the past, heating oil swaps. At December 31, 2012, the Company had protected the price of substantially all of its 2013 purchases. At December 31, 2012, the Company had purchased heating oil call options for approximately 60 million gallons for the purpose of managing the price risk associated with future diesel purchases.

The Company also purchased heating oil call options to hedge the fuel surcharges on its barge and rail shipments that cover increases in diesel fuel prices. These positions reduce the Company's risk of cash flow fluctuations related to these surcharges but the positions are not accounted for as hedges. At December 31, 2012, the Company held purchased call options for approximately 15 million gallons for the purpose of managing the fluctuations in cash flows associated with fuel surcharges on future shipments.

Coal risk management positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market in order to manage its exposure to coal prices. The Company has exposure to the risk of fluctuating coal prices related to forecasted sales or purchases of coal or to the risk of changes in the fair value of a fixed price physical sales contract. Certain derivative contracts may be designated as hedges of these risks.

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Notes to Consolidated Financial Statements (Continued)

At December 31, 2012, the Company held derivatives for risk management purposes that are expected to settle in the following years:

(Tons in thousands)	2013	2014	2015	Total
Coal sales	6,704	4,260	780	11,744
Coal purchases	1,410	1,260	—	2,670

Coal trading positions

The Company may sell or purchase forward contracts, swaps and options in the over-the-counter coal market for trading purposes. The Company is exposed to the risk of changes in coal prices on the value of its coal trading portfolio. The estimated future realization of the value of the trading portfolio is $1.1 million of losses in 2013 and $1.5 million of gains in 2014.

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Notes to Consolidated Financial Statements (Continued)

Tabular derivatives disclosures

The Company's contracts with certain of its counterparties allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. Such netting arrangements reduce the Company's credit exposure related to these counterparties. For classification purposes, the Company records the net fair value of all the positions with a given counterparty as a net asset or liability in the consolidated balance sheets. The amounts shown in the table below represent the fair value position of individual contracts, and not the net position presented in the accompanying consolidated balance sheets. The fair value and location of derivatives reflected in the accompanying consolidated balance sheets are as follows:

Fair Value of Derivatives (In thousands)	December 31, 2012 Asset Derivative	December 31, 2012 Liability Derivative		December 31, 2011 Asset Derivative	December 31, 2011 Liability Derivative	
Derivatives Designated as Hedging Instruments						
Heating oil — diesel purchases	$ —	$ —		$ 8,997	$ —	
Coal	3,277	(10)		1,109	—	
Total	3,277	(10)		10,106	—	
Derivatives Not Designated as Hedging Instruments						
Heating oil — diesel purchases	7,379	—		—	—	
Heating oil — fuel surcharges	1,961	—		1,797	—	
Coal — held for trading purposes	17,403	(16,933)		15,505	(19,927)	
Coal — risk management	24,843	(7,342)		14,855	(6,035)	
Total	51,586	(24,275)		32,157	(25,962)	
Total derivatives	54,863	(24,285)		42,263	(25,962)	
Effect of counterparty netting	(22,548)	22,548		(18,134)	18,134	
Net derivatives as classified in the balance sheets	$ 32,315	$ (1,737)	$ 30,578	$ 24,129	$ (7,828)	$ 16,301

		December 31, 2012	December 31, 2011
Net derivatives as reflected on the balance sheets			
Heating oil	Other current assets	$ 9,340	$ 10,794
Coal	Coal derivative assets	22,975	13,335
	Coal derivative liabilities	(1,737)	(7,828)
		$ 30,578	$ 16,301

The Company had a current asset for the right to reclaim cash collateral of $16.2 million and $12.4 million at December 31, 2012 and December 31, 2011, respectively. These amounts are not included with the derivatives presented in the table above and are included in "other current assets" in the accompanying consolidated balance sheets.

During the first quarter of 2012, the Company determined the effectiveness of the heating oil options could not be established as of December 31, 2011 and on an ongoing basis. As a result, the amount remaining in

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Notes to Consolidated Financial Statements (Continued)

accumulated other comprehensive income of $8.2 million was recorded in the "other operating income, net" line on the consolidated statement of operations, or $5.2 million net of income taxes,.

The effects of derivatives on measures of financial performance are as follows:

Derivatives Used in Cash Flow Hedging Relationships (in thousands)

	Gain (Loss) Recognized in Other Comprehensive Income(Effective Portion)			Gains (Losses) Reclassified from Other Comprehensive Income into Income (Effective Portion)		
For the year ended December 31,	2012	2011	2010	2012	2011	2010
Heating oil — diesel purchases(2)	$ —	$ 1,294	$ (149)	$ —	$ 14,866	$ 437
Coal sales(1)	7,690	4,923	(4,714)	2,675	1,572	(1,602)
Coal purchases(2)	(2,440)	(2,009)	5,145	—	—	(1,202)
Totals	$ 5,250	$ 4,208	$ 282	$ 2,675	$ 16,438	$ (2,367)

No ineffectiveness or amounts excluded from effectiveness testing relating to the Company's cash flow hedging relationships were recognized in the results of operations in the twelve month periods ended December 31, 2012 and 2011.

Derivatives Not Designated as Hedging Instruments (in thousands)

	Gain (Loss) Recognized		
For the year ended December 31	2012	2011	2010
Coal — unrealized(3)	$ 8,272	$ 6,438	$ (10,991)
Coal — realized(4)	$ 43,990	$ (7)	$ 4,542
Heating oil — diesel purchases(4)	$ (22,281)	$ (2,906)	$ —
Heating oil — fuel surcharges(4)	$ (2,209)	$ —	$ —

Location in statement of operations:

(1) — Revenues

(2) — Cost of sales

(3) — Change in fair value of coal derivatives and coal trading activities, net

(4) — Other operating income, net

The Company recognized net unrealized and realized gains of $8.3 million, losses of $3.5 million, and gains of $2.1 million during the year ended December 31, 2012, 2011, and 2010, respectively, related to its trading portfolio, which are included in the caption "Change in fair value of coal derivatives and coal trading activities, net" in the accompanying consolidated statements of operations, and are not included in the previous tables reflecting the effects of derivatives on measures of financial performance.

Based on fair values at December 31, 2012, gains on derivative contracts designated as hedge instruments in cash flow hedges of approximately $2.2 million are expected to be reclassified from other comprehensive income into earnings during the next twelve months.

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Notes to Consolidated Financial Statements (Continued)

10. Inventories

Inventories consist of the following:

	December 31 2012	December 31 2011
	(In thousands)	
Coal	$ 180,917	$ 206,517
Repair parts and supplies	172,139	163,527
Work-in-process	12,368	7,446
	$ 365,424	$ 377,490

The repair parts and supplies are stated net of an allowance for slow-moving and obsolete inventories of $13.6 million at December 31, 2012, and $13.1 million at December 31, 2011.

11. Fair Value Measurements

The hierarchy of fair value measurements prioritizes the inputs to valuation techniques used to measure fair value. The levels of the hierarchy, as defined below, give the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs.

- Level 1 is defined as observable inputs such as quoted prices in active markets for identical assets. Level 1 assets include available-for-sale equity securities, U.S. Treasury securities, and coal futures that are submitted for clearing on the New York Mercantile Exchange.

- Level 2 is defined as observable inputs other than Level 1 prices. These include quoted prices for similar assets or liabilities in an active market, quoted prices for identical assets and liabilities in markets that are not active, or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities. The Company's level 2 assets and liabilities include U.S. government agency securities and commodity contracts (coal and heating oil) with fair values derived from quoted prices in over-the-counter markets or from prices received from direct broker quotes.

- Level 3 is defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. These include the Company's commodity option contracts (coal and heating oil) valued using modeling techniques, such as Black-Scholes, that require the use of inputs, particularly volatility, that are rarely observable. Changes in the unobservable inputs would not have a significant impact on the reported Level 3 fair values at December 31, 2012.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

The table below sets forth, by level, the Company's financial assets and liabilities that are recorded at fair value in the accompanying consolidated balance sheet:

	Fair Value at December 31, 2012			
	Total	Level 1	Level 2	Level 3
	(In thousands)			
Assets:				
Investments in marketable securities	$ 239,652	$ 103,439	$ 136,213	$ —
Derivatives	32,315	22,465	510	9,340
Total assets	$ 271,967	$ 125,904	$ 136,723	$ 9,340
Liabilities:				
Derivatives	$ 1,737	$ —	$ 571	$ 1,166

The Company's contracts with certain of its counterparties allow for the settlement of contracts in an asset position with contracts in a liability position in the event of default or termination. For classification purposes, the Company records the net fair value of all the positions with these counterparties as a net asset or liability. Each level in the table above displays the underlying contracts according to their classification in the accompanying consolidated balance sheet, based on this counterparty netting.

The following table summarizes the change in the fair values of financial instruments categorized as level 3.

	Year Ended December 31, 2012
Balance, beginning of period	$ 6,211
Realized and unrealized losses recognized in earnings, net	(13,399)
Realized and unrealized losses recognized in other comprehensive income, net	—
Purchases	17,312
Issuances	—
Settlements	(1,950)
Ending balance	$ 8,174

Net unrealized losses during the twelve month period ended December 31, 2012 related to level 3 financial instruments held on December 31, 2012 were $5.4 million.

Fair Value of Long-Term Debt

At December 31, 2012 and December 31, 2011, the fair value of the Company's debt, including amounts classified as current, was $5.0 billion and $4.2 billion, respectively. Fair values are based upon observed prices in an active market when available or from valuation models using market information, which fall into Level 2 in the fair value hierarchy.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

12. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	December 31	
	2012	2011
	(In thousands)	
Payroll and employee benefits	$ 72,405	$ 65,323
Taxes other than income taxes	121,029	133,331
Interest	42,413	55,266
Acquired sales contracts (See Note 4)	14,038	38,441
Workers' compensation (See Note 17)	10,371	11,666
Asset retirement obligations (See Note 14)	38,920	27,119
Other	18,842	17,061
	$ 318,018	$ 348,207

13. Taxes

The Company is subject to U.S. federal income tax as well as income tax in multiple state jurisdictions. The tax years 2006 through 2012 remain open to examination for U.S. federal income tax matters and 1998 through 2012 remain open to examination for various state income tax matters.

Significant components of the provision for (benefit from) income taxes are as follows:

	Year Ended December 31		
	2012	2011	2010
	(In thousands)		
Current:			
Federal	$ (20,022)	$ (20,164)	$ 34,304
State	575	1,212	2,283
Total current	(19,447)	(18,952)	36,587
Deferred:			
Federal	(322,104)	13,214	(18,506)
State	7,834	(1,851)	(367)
Total deferred	(314,270)	11,363	(18,873)
	$ (333,717)	$ (7,589)	$ 17,714

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

A reconciliation of the statutory federal income tax provision (benefit) at the statutory rate to the actual provision for (benefit from) income taxes follows:

	Year Ended December 31		
	2012	2011	2010
	(In thousands)		
Income tax provision (benefit) at statutory rate	$ (356,185)	$ 46,933	$ 61,800
Percentage depletion allowance	(40,698)	(61,971)	(49,152)
Goodwill	56,916	—	—
State taxes, net of effect of federal taxes	(23,423)	(3,055)	2,299
Change in valuation allowance	31,832	2,416	(383)
Other, net	(2,159)	8,088	3,150
	$ (333,717)	$ (7,589)	$ 17,714

In 2012, 2011 and 2010, compensatory stock options and other equity based compensation awards were exercised resulting in a tax expense (benefit) of $0.3 million, $(0.4) million and $(0.8) million, respectively. The tax benefit will be recorded in paid-in capital at such point in time when a cash tax benefit is recognized.

Significant components of the Company's deferred tax assets and liabilities that result from carryforwards and temporary differences between the financial statement basis and tax basis of assets and liabilities are summarized as follows:

	December 31	
	2012	2011
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 496,330	$ 324,393
Alternative minimum tax credit carryforwards	150,014	151,404
Reclamation and mine closure	104,570	93,914
Goodwill	43,839	—
Acquired sales contracts	38,735	44,717
Workers' compensation	32,241	26,266
Retiree benefit plans	32,087	24,456
Other, primarily accrued liabilities	113,777	120,993
Gross deferred tax assets	1,011,593	786,143
Valuation allowance	(34,663)	(2,831)
Total deferred tax assets	976,930	783,312
Deferred tax liabilities:		
Plant and equipment	1,411,446	1,566,769
Deferred development	77,013	67,728
Investment in tax partnerships	72,513	66,502
Other	12,780	17,015
Total deferred tax liabilities	1,573,752	1,718,014
Net deferred tax asset (liability)	(596,822)	(934,702)
Current asset (liability)	67,360	42,051
Non-current deferred tax asset (liability)	$ (664,182)	$ (976,753)

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

The Company has federal net operating loss carryforwards for regular income tax purposes of $1.3 billion at December 31, 2012 that will expire between 2024 and 2032. The Company has an alternative minimum tax credit carryforward of $150.0 million at December 31, 2012, which has no expiration date and can be used to offset future regular tax in excess of the alternative minimum tax.

During 2008, the Company reached a settlement with the IRS regarding the Company's treatment of the acquisition of the coal operations of Atlantic Richfield Company ("ARCO") and the simultaneous combination of the acquired ARCO operations and the Company's Wyoming operations into the Arch Western joint venture. The settlement did not result in a net change in deferred tax assets, but involved a re-characterization of deferred tax assets, including an increase in net operating loss carryforwards of $145.1 million and other amortizable assets which will provide additional tax deductions through 2013. A portion of these cash tax benefits accrued to ARCO pursuant to the original purchase agreement, including $0.8 million and $1.3 million paid in 2011 and 2010, respectively, that was recorded as goodwill.

The Company has recorded a valuation allowance for a portion of its deferred tax assets that management believes, more likely than not, will not be realized. Management reassesses the ability to realize its deferred tax assets annually in the fourth quarter or when circumstances indicate that the ability to realize deferred tax assets has changed. This review resulted in increases (decreases) in the valuation allowance of $31.8 million, $2.1 million and $(0.4) million in 2012, 2011 and 2010, respectively. The valuation allowance relates to certain state and foreign net operating loss benefits.

A reconciliation of the beginning and ending amounts of gross unrecognized tax benefits follows:

	(In thousands)
Balance at January 1, 2010	$ 6,670
Additions based on tax positions related to the current year	1,493
Additions for tax positions of prior years	85
Reductions for tax positions of prior years	(3,830)
Balance at December 31, 2010	4,418
Additions based on tax positions related to the current year	1,626
Additions for tax positions of prior years	2,754
Balance at December 31, 2011	8,798
Additions based on tax positions related to the current year	409
Additions for tax positions of prior years	21,943
Balance at December 31, 2012	$ 31,150

If recognized, the entire amount of the gross unrecognized tax benefits at December 31, 2012 would affect the effective tax rate.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company had accrued interest and penalties of $1.0 million and $0.8 million at December 31, 2012 and 2011, respectively, of which $0.2 million was recognized as expense during 2012 and 2011. No gross unrecognized tax benefits are expected to be reduced in the next 12 months due to the expiration of the statute of limitations.

14. Asset Retirement Obligations

The Company's asset retirement obligations arise from the Federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes, which require that mine property be restored in accordance with specified standards and an approved reclamation plan. The required reclamation activities to be performed are outlined in the

Company's mining permits. These activities include reclaiming the pit and support acreage at surface mines, sealing portals at underground mines, and reclaiming refuse areas and slurry ponds.

The following table describes the changes to the Company's asset retirement obligation liability:

	Year Ended December 31	
	2012	2011
	(In thousands)	
Balance at January 1 (including current portion)	$ 473,903	$ 343,119
Accretion expense	39,020	33,601
Obligations incurred or acquired	—	115,019
Adjustments to the liability from changes in estimates	4,400	11,176
Liabilities settled	(68,698)	(29,012)
Balance at December 31	$ 448,625	$ 473,903
Current portion included in accrued expenses	(38,920)	(27,119)
Noncurrent liability	$ 409,705	$ 446,784

The liabilities settled in 2012 were the result of the acceleration of reclamation activities, primarily at the Black Thunder mining complex, as employees and equipment impacted by mine production cutbacks in response to market conditions were redirected to reclamation activities. Liabilities settled of $29.0 million in 2011 related to reclamation activities at the Black Thunder mining complex related to a pit acquired with the Jacobs Ranch operations in 2009.

As of December 31, 2012, the Company had $262.9 million in surety bonds outstanding, $388.4 million in self-bonding, and $18.0 million in letters of credit to secure reclamation bonding obligations.

15. Capital Stock

On March 1, 2012, the Company filed a registration statement on Form S-3 with the SEC. The registration statement allows the Company to offer, from time to time, an unlimited amount of debt securities, preferred stock, depositary shares, purchase contracts, purchase units, common stock and related rights and warrants.

Common Stock

On June 8, 2011, the Company sold 48 million shares of its common stock at a public offering price of $27.00 per share. The $1.25 billion in net proceeds from the issuance were used to finance the acquisition of ICG. On July 8, 2011, the Company issued an additional 0.7 million shares of its common stock under the same terms and conditions to cover underwriters' over-allotments for net proceeds of $18.4 million.

Stock Repurchase Plan

The Company's share repurchase program allows for the purchase of up to 14,000,000 shares of the Company's common stock. At December 31, 2012, 10,925,800 shares of common stock were available for repurchase under the plan. There were no purchases made under the plan during 2012, 2011 or 2010. There is no expiration date on the program. Any future repurchases under the plan will be made at management's discretion and will depend on market conditions and other factors.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

16. Stock-Based Compensation and Other Incentive Plans

Under the Company's Stock Incentive Plan (the "Incentive Plan"), 18,000,000 shares of the Company's common stock are reserved for awards to officers and other selected key management employees of the Company. The Incentive Plan provides the Board of Directors with the flexibility to grant stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance stock or units, merit awards, phantom stock awards and rights to acquire stock through purchase under a stock purchase program ("Awards"). Awards the Board of Directors elects to pay out in cash do not count against the 18,000,000 shares authorized in the Incentive Plan. The Incentive Plan calls for the adjustment of shares awarded under the plan in the event of a split.

As of December 31, 2012, the Company had stock options, restricted stock and restricted stock units outstanding under the Incentive Plan.

Stock Options

Stock options are granted at a price equal to the closing market price of the Company's common stock on the date of grant and are generally subject to vesting provisions of at least one year from the date of grant. Information regarding stock option activity under the Incentive Plan follows for the year ended December 31, 2012:

	Common Shares (In thousands)	Weighted Average Exercise Price (In thousands)	Aggregate Intrinsic Value (In thousands)	Average Contract Life
Options outstanding at January 1	4,953	$ 26.72		
Granted	1,311	13.28		
Exercised	(527)	9.79		
Canceled	(73)	31.17		
Expired	(449)	13.89		
Options outstanding at December 31	5,215	25.99	$ 4	6.67
Options exercisable at December 31	2,847	32.26	—	5.40

The aggregate intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $1.8 million, $2.6 million and $3.0 million, respectively.

Information regarding changes in stock options outstanding and not yet vested and the related grant-date fair value under the Incentive Plan follows for the year ended December 31, 2012:

	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Unvested options at January 1	1,796	$ 10.96
Granted	1,311	5.27
Vested	(721)	11.13
Canceled	(17)	9.81
Unvested options at December 31	2,369	7.77

Compensation expense related to stock options for the years ended December 31, 2012, 2011 and 2010 was $8.0 million, $8.8 million and $10.6 million, respectively. As of December 31, 2012, there was $7.0 million of unrecognized compensation cost related to the unvested stock options. The total grant-date fair value of options vested during the years ended December 31, 2012, 2011 and 2010 was $8.0 million, $9.9 million and $10.6 million, respectively. The options provide for the continuation of vesting for retirement-eligible recipients that meet certain criteria. The expense for these options is recognized through the date that the employee first becomes eligible to retire and is no longer required to provide service to earn part or all of the award. The majority of the cost relating to the stock-based compensation plans is included primarily in selling, general and administrative expenses in the accompanying consolidated statements of income.

Weighted average assumptions used in the Black-Scholes option pricing model for granted options follow:

	Year Ended December 31		
	2012	2011	2010
Weighted average grant-date fair value per share of options granted	$ 5.27	$ 14.18	$ 9.43
Assumptions (weighted average):			
Risk-free interest rate	0.76%	1.92%	2.16%
Expected dividend yield	2.92%	1.25%	1.99%
Expected volatility	60.72%	57.4%	57.1%
Expected life (in years)	4.5	4.5	4.5

Expected volatilities are based on historical stock price movement and implied volatility from traded options on the Company's stock. The expected life of the option was determined based on historical exercise activity. Most options granted vest over a period of three to four years.

Restricted Stock and Restricted Stock Unit Awards

The Company may issue restricted stock and restricted stock units, which require no payment from the employee. Restricted stock cliff-vests at various dates and restricted stock units typically vest ratably over three years. Compensation expense is based on the fair value on the grant date and is recorded ratably over the vesting period. During the vesting period, the employee receives cash compensation equal to the amount of dividends that would have been paid on the underlying shares.

Information regarding restricted stock and restricted stock unit activity and weighted average grant-date fair value follows for the year ended December 31, 2012:

	Restricted Stock		Restricted Stock Units	
	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value	Common Shares (In thousands)	Weighted Average Grant-Date Fair Value
Outstanding at January 1	182	$ 26.68	27	$ 52.69
Granted	22	13.44	547	13.31
Vested	(10)	22.89	(27)	52.69
Canceled	(6)	32.49	(36)	13.93
Outstanding at December 31	188	25.14	511	13.26

The weighted average fair value of restricted stock granted during 2011 and 2010 was $30.42 and $22.03, respectively. There were no restricted stock units granted during 2011 or 2010. The total grant-date fair value of restricted stock that vested during 2012, 2011 and 2010 was $0.2 million, $1.1 million and $0.4 million, respectively. The total grant-date fair value of restricted stock units that vested during 2012 and 2011 was $1.4 million in each year. There were no restricted stock units that vested during 2010.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Unearned compensation of $6.9 million will be recognized over the remaining vesting period of the outstanding restricted stock and restricted stock units. The Company recognized expense of approximately $3.5 million, $2.1 million and $1.1 million related to restricted stock and restricted stock units for the years ended December 31, 2012, 2011 and 2010, respectively, primarily in selling, general and administrative expenses.

Long-Term Incentive Compensation

The Company has a long-term incentive program that allows for the award of performance units. The total number of units earned by a participant is based on financial and operational performance measures, and may be paid out in cash or in shares of the Company's common stock. The Company recognizes compensation expense over the three year term of the grant. The liabilities are remeasured quarterly. The Company recognized $8.1 million, $2.7 million and $3.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. The expense is included primarily in selling, general and administrative expenses in the accompanying consolidated statements of income. Amounts accrued under the plan were $13.1 million and $9.6 million at December 31, 2012 and 2011, respectively.

Deferred Compensation Plan

The Company maintains a deferred compensation plan that allows eligible employees to defer receipt of compensation until the dates elected by the participant. Participants in the plan may defer up to 85% of their base salaries and up to 100% of their annual incentive awards. The plan also allows participants to defer receipt of up to 100% of the shares under any restricted stock unit or performance-contingent stock awards. The amounts deferred are invested in accounts that mirror the gains and losses of a number of different investment funds, including a hypothetical investment in shares of the Company's common stock. Participants are always vested in their deferrals to the plan and any related earnings. The Company has established a grantor trust to fund the obligations under the plan. The trust has purchased corporate-owned life insurance to offset these obligations. The net cash surrender values of the policies of $35.4 million and $35.8 million at December 31, 2012 and 2011, respectively, are included in other noncurrent assets in the accompanying consolidated balance sheets. The participants have an unsecured contractual commitment by the Company to pay the amounts due under the plan. Any assets placed in trust by the Company to fund future obligations of the plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the company as to their deferred compensation in the plans.

Under the plan, the Company credits each participant's account with the number of units equal to the number of shares or units that the participant could purchase or receive with the amount of compensation deferred, based upon the fair market value of the underlying investment on that date. The amount the employee will receive from the plan will be based on the number of units credited to each participant's account, valued on the basis of the fair market value of an equivalent number of shares or units of the underlying investment on that date. The liability under the plan was $31.3 million at December 31, 2012 and $32.7 million at December 31, 2011.

The Company's net income (expense) related to the deferred compensation plan for the years ended December 31, 2012, 2011 and 2010 was $3.3 million, $6.2 million and $(2.8) million, respectively, most of which is included in selling, general and administrative expenses in the accompanying consolidated statements of income.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

17. Accrued Workers' Compensation

The Company is liable under the Federal Mine Safety and Health Act of 1969, as subsequently amended, to provide for pneumoconiosis (occupational disease) benefits to eligible employees, former employees, and dependents. The Company is also liable under various states' statutes for occupational disease benefits. The Company currently provides for federal and state claims principally through a self-insurance program. The occupational disease benefit obligation represents the present value of the actuarially computed present and future liabilities for such benefits over the employees' applicable years of service.

In addition, the Company is liable for workers' compensation benefits for traumatic injuries that are accrued as injuries are incurred. Traumatic claims are either covered through self-insured programs or through state-sponsored workers' compensation programs.

Workers' compensation expense consists of the following components:

	Year Ended December 31		
	2012	2011	2010
		(In thousands)	
Self-insured occupational disease benefits:			
Service cost	$ 1,993	$ 2,059	$ 727
Interest cost	2,400	1,799	675
Net amortization	(453)	(493)	(1,860)
Curtailments	3,022	—	—
Total occupational disease	6,962	3,365	(458)
Traumatic injury claims and assessments	26,565	16,979	9,263
Total workers' compensation expense	$ 33,527	$ 20,344	$ 8,805

The reconciliation of changes in the benefit obligation of the occupational disease liability is as follows:

	December 31	
	2012	2011
	(In thousands)	
Beginning of year obligation	$ 54,184	$ 17,412
Service cost	1,993	2,059
Interest cost	2,400	1,799
Actuarial loss (gain)	(5,373)	7,081
Benefit and administrative payments	(1,873)	(1,097)
Curtailments	7,100	—
Acquisition of ICG	—	26,930
Net obligation at end of year	$ 58,431	$ 54,184

At December 31, 2012 and 2011, accumulated losses of $4.7 million and $5.5 million, respectively, were not yet recognized in occupational disease cost and were recorded in accumulated other comprehensive income. The expected accumulated loss that will be amortized from accumulated other comprehensive income into occupational disease cost in 2013 is $0.9 million.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

The following table provides the assumptions used to determine the projected occupational disease obligation:

	Year Ended December 31		
	2012	2011	2010
Weighted average assumptions:			
Discount rate	4.54%	5.10%	5.96%
Cost escalation rate	3.00%	3.00%	3.00%

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for workers' compensation benefits:

	December 31	
	2012	2011
	(In thousands)	
Occupational disease costs	$ 58,431	$ 54,184
Traumatic and other workers' compensation claims	33,569	29,430
Total obligations	92,000	83,614
Less amount included in accrued expenses	10,371	11,666
Noncurrent obligations	$ 81,629	$ 71,948

As of December 31, 2012, the Company had $61.1 million in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

18. Employee Benefit Plans

Defined Benefit Pension and Other Postretirement Benefit Plans

The Company provides funded and unfunded non-contributory defined benefit pension plans covering certain of its salaried and hourly employees. Benefits are generally based on the employee's age and compensation. The Company funds the plans in an amount not less than the minimum statutory funding requirements or more than the maximum amount that can be deducted for U.S. federal income tax purposes.

The Company also currently provides certain postretirement medical and life insurance coverage for eligible employees. Generally, covered employees who terminate employment after meeting eligibility requirements are eligible for postretirement coverage for themselves and their dependents. The salaried employee postretirement benefit plans are contributory, with retiree contributions adjusted annually, and contain other cost-sharing features such as deductibles and coinsurance. The Company's current funding policy is to fund the cost of all postretirement benefits as they are paid.

Employees acquired with the ICG acquisition were brought over in their existing plan. Subsequently, the terms of the plan were amended to change vesting periods, coverage caps, and eligible ages, resulting in a reduction of the benefit obligation of $55.5 million.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Obligations and Funded Status.

Summaries of the changes in the benefit obligations, plan assets and funded status of the plans are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(In thousands)			
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligations at January 1	$ 333,951	$ 297,707	$ 45,129	$ 39,633
Service cost	27,466	16,490	2,142	3,917
Interest cost	15,668	16,253	2,020	3,279
Plan amendments	—	(3,235)	2,183	(55,542)
Benefits paid	(23,624)	(18,848)	(4,244)	(1,669)
Curtailments	(687)	—	(708)	—
Acquisition of ICG	—	—	—	48,441
Other-primarily actuarial loss (gain)	38,120	25,584	2,804	7,070
Benefit obligations at December 31	$ 390,894	$ 333,951	$ 49,326	$ 45,129
CHANGE IN PLAN ASSETS				
Value of plan assets at January 1	$ 285,074	$ 247,713	$ —	$ —
Actual return on plan assets	42,396	9,443	—	—
Employer contributions	19,028	46,766	4,244	1,669
Benefits paid	(23,624)	(18,848)	(4,244)	(1,669)
Value of plan assets at December 31	$ 322,874	$ 285,074	$ —	$ —
Accrued benefit cost	(68,020)	(48,877)	(49,326)	(45,129)
ITEMS NOT YET RECOGNIZED AS A COMPONENT OF NET PERIODIC BENEFIT COST				
Prior service credit (cost)	$ 1,890	$ 1,736	$ 45,938	$ 62,920
Accumulated gain (loss)	(68,915)	(68,302)	(1,531)	1,795
	$ (67,025)	$ (66,566)	$ 44,407	$ 64,715
BALANCE SHEET AMOUNTS				
Current liability	$ (390)	$ (633)	$ (4,240)	$ (2,820)
Noncurrent liability	$ (67,630)	$ (48,244)	$ (45,086)	$ (42,309)
	$ (68,020)	$ (48,877)	$ (49,326)	$ (45,129)

Pension Benefits

The accumulated benefit obligation for all pension plans was $366.1 million and $314.7 million at December 31, 2012 and 2011, respectively. The accumulated benefit obligation differs from the benefit obligation in that it includes no assumption about future compensation levels.

The benefit obligation and the accumulated benefit obligation for the Company's unfunded pension plan were $10.6 million and $9.4 million, respectively, at December 31, 2012.

The prior service credit and net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2013 are $0.2 million and $16.2 million, respectively.

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Other Postretirement Benefits

The prior service credit and net gain that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2013 is $11.0 million and $0.3 million, respectively.

Components of Net Periodic Benefit Cost. The following table details the components of pension benefit costs:

Year Ended December 31,	Pension Benefits 2012	Pension Benefits 2011	Pension Benefits 2010	Other Postretirement Benefits 2012	Other Postretirement Benefits 2011	Other Postretirement Benefits 2010
	(In thousands)					
Service cost	$ 27,466	$ 16,490	$ 15,870	$ 2,142	$ 3,917	$ 1,509
Interest cost	15,668	16,253	15,822	2,020	3,279	2,083
Curtailments	324	—	—	(4,049)	—	—
Expected return on plan assets*	(22,030)	(21,812)	(19,392)	—	—	—
Amortization of prior service cost (credit)	259	(189)	173	(11,458)	(2,364)	(2,364)
Amortization of other actuarial losses (gains)	14,666	8,748	7,130	(522)	(3,100)	(2,918)
Net benefit cost	$ 36,353	$ 19,490	$ 19,603	$ (11,867)	$ 1,732	$ (1,690)

* The Company does not fund its other postretirement benefit obligations.

The differences generated from changes in assumed discount rates and returns on plan assets are amortized into earnings over a five-year period.

Assumptions. The following table provides the assumptions used to determine the actuarial present value of projected benefit obligations at December 31.

	Pension Benefits 2012	Pension Benefits 2011	Other Postretirement Benefits 2012	Other Postretirement Benefits 2011
Weighted average assumptions:				
Discount rate	4.13%	4.91%	3.64%	4.52%
Rate of compensation increase	3.39%	3.39%	N/A	N/A

The following table provides the assumptions used to determine net periodic benefit cost for years ended December 31.

	Pension Benefits 2012	Pension Benefits 2011	Pension Benefits 2010	Other Postretirement Benefits 2012	Other Postretirement Benefits 2011	Other Postretirement Benefits 2010
Weighted average assumptions:						
Discount rate	4.91%	5.71%	5.97%	4.52%	5.23%	5.67%
Rate of compensation increase	3.39%	3.39%	3.39%	N/A	N/A	N/A
Expected return on plan assets	7.75%	8.50%	8.50%	N/A	N/A	N/A

The Company establishes the expected long-term rate of return at the beginning of each fiscal year based upon historical returns and projected returns on the underlying mix of invested assets. The Company utilizes modern portfolio theory modeling techniques in the development of its return assumptions. This technique projects rates of return that can be generated through various asset allocations that lie within the risk tolerance set forth by members of the Company's pension committee (the "Pension Committee"). The risk assessment provides a link between a pension's risk capacity, management's willingness to accept investment risk and the asset allocation process, which ultimately leads to the return generated by the invested assets.

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The health care cost trend rate assumed for 2013 is 7.5% and is expected to reach an ultimate trend rate of 4.5% by 2028. A one-percentage-point increase in the health care cost trend rate would have increased the postretirement benefit obligation at December 31, 2012 by $1.0 million. A one-percentage-point decrease in the health care cost trend rate would have decreased the postretirement benefit obligation at December 31, 2012 by $0.8 million. The effect of these changes would have had an insignificant impact on the net periodic postretirement benefit costs.

Plan Assets

The Pension Committee is responsible for overseeing the investment of pension plan assets. The Pension Committee is responsible for determining and monitoring appropriate asset allocations and for selecting or replacing investment managers, trustees and custodians. The pension plan's current investment targets are 65% equity, 30% fixed income securities and 5% cash. The Pension Committee reviews the actual asset allocation in light of these targets on a periodic basis and rebalances among investments as necessary. The Pension Committee evaluates the performance of investment managers as compared to the performance of specified benchmarks and peers and monitors the investment managers to ensure adherence to their stated investment style and to the plan's investment guidelines.

The Company's pension plan assets at December 31, 2012 and 2011, respectively, are categorized below according to the fair value hierarchy as defined in Note 11, "Fair Value Measurements":

	Total		Level 1		Level 2		Level 3	
	2012	2011	2012	2011	2012	2011	2012	2011
	(In thousands)							
Equity Securities:(A)								
U.S. small-cap	$ 13,099	$ 11,178	$ 13,099	$ 11,178	$ —	$ —	$ —	$ —
U.S. mid-cap	43,946	50,264	12,717	23,474	31,229	26,790	—	—
U.S. large-cap	102,922	91,561	48,536	44,820	54,386	46,741	—	—
Non-U.S.	27,251	22,509	—	—	27,251	22,509	—	—
Fixed income securities:								
U.S. government securities(B)	24,202	13,454	23,483	12,738	719	716	—	—
Non-U.S. government securities(C)	3,681	2,968	—	—	3,681	2,968	—	—
U.S. government asset and mortgage backed securities(D)	781	800	—	—	781	800	—	—
Corporate fixed income(E)	14,016	14,004	—	—	14,016	14,004	—	—
State and local government securities(F)	9,903	18,416	—	—	9,903	18,416	—	—
Other fixed income(G)	61,765	51,470	—	—	61,765	51,470	—	—
Short-term investments(H)	20,894	8,029	—	—	20,894	8,029	—	—
Other investments(I)	414	421	—	—	414	421	—	—
Total	$ 322,874	$ 285,074	$ 97,835	$ 92,210	$ 225,039	$ 192,864	$ —	$ —

(A) Equity securities includes investments in 1) common stock, 2) preferred stock and 3) mutual funds. Investments in common and preferred stocks are valued using quoted market prices multiplied by the number of shares owned. Investments in mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date and are traded on listed exchanges.

(B) U.S. government securities includes agency and treasury debt. These investments are valued using dealer quotes in an active market.

(C) Non-U.S. government securities includes debt securities issued by foreign governments and are valued utilizing a price spread basis valuation technique with observable sources from investment dealers and research vendors.

(D) U.S. government asset and mortgage backed securities includes government-backed mortgage funds which are valued utilizing an income approach that includes various valuation techniques and sources such as discounted cash flows models, benchmark yields and securities, reported trades, issuer trades and/or other applicable data.

(E) Corporate fixed income is primarily comprised of corporate bonds and certain corporate asset-backed securities that are denominated in the U.S. dollar and are investment-grade securities. These investments are valued using dealer quotes.

(F) State and local government securities include different U.S. state and local municipal bonds and asset backed securities, these investments are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes, benchmark yields and securities, reported trades, issuer trades and/or other applicable data.

(G) Other fixed income investments are actively managed fixed income vehicles that are valued at the net asset value per share multiplied by the number of shares held as of the measurement date.

(H) Short-term investments include governmental agency funds, government repurchase agreements, commingled funds, and pooled funds and mutual funds. Governmental agency funds are valued utilizing an option adjusted spread valuation technique and sources such as interest rate generation processes, benchmark yields and broker quotes. Investments in governmental repurchase agreements, commingled funds and pooled funds and mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date.

(I) Other investments includes cash, forward contracts, derivative instruments, credit default swaps, interest rate swaps and mutual funds. Investments in interest rate swaps are valued utilizing a market approach that includes various valuation techniques and sources such as value generation models, broker quotes in active and non-active markets, benchmark yields and securities, reported trades, issuer trades and/or other applicable data. Forward contracts and derivative instruments are valued at their exchange listed price or broker quote in an active market. The mutual funds are valued at the net asset value per share multiplied by the number of shares held as of the measurement date and are traded on listed exchanges.

Cash Flows. The Company expects to make contributions of $0.9 million to the pension plans in 2013, which is impacted by the Moving Ahead for Progress in the 21st Century Act (MAP-21) enacted July 6, 2012. MAP-21 does not reduce the Company's obligations under the plan, but redistributes the timing of required payments by providing near term funding relief for sponsors under the Pension Protection Act.

The following represents expected future benefit payments from the plan, which reflect expected future service, as appropriate:

	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2013	$ 21,275	$ 3,987
2014	23,674	4,204
2015	24,210	4,430
2016	28,464	4,720
2017	32,124	4,893
Years 2018-2022	190,016	24,895
	$ 319,763	$ 47,129

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Other Plans

The Company sponsors savings plans which were established to assist eligible employees provide for their future retirement needs. The Company's expense, representing its contributions to the plans, was $27.2 million, $25.9 million and $18.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

19. Risk Concentrations

Credit Risk and Major Customers

The Company has a formal written credit policy that establishes procedures to determine creditworthiness and credit limits for trade customers and counterparties in the over-the-counter coal market. Generally, credit is extended based on an evaluation of the customer's financial condition. Collateral is not generally required, unless credit cannot be established. Credit losses are provided for in the financial statements and historically have been minimal.

The Company markets its steam coal principally to domestic and foreign electric utilities and its metallurgical coal to domestic and foreign steel producers. Revenues from export sales were $1.2 billion, $920.0 million and $471.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012 and 2011, accounts receivable from electric utilities totaled $159.5 million and $261.2 million, respectively, or 65% and 69% of total trade receivables, respectively. As of December 31, 2012 and 2011, accounts receivable from sales of metallurgical-quality coal totaled $86.6 million and $117.4 million, respectively, or 35% and 31%, of total trade receivables, respectively.

The Company uses shipping destination as the basis for attributing revenue to individual countries. The Company's foreign revenues by geographical location for the year ended December 31, 2012, follows:

	December 31, 2012 (In thousands)
Europe (including Morocco and Turkey)	$ 674,754
Asia	203,193
North America	72,542
South America	57,184
Brokered sales	145,438
Total	$ 1,153,111

The Company is committed under long-term contracts to supply steam coal that meets certain quality requirements at specified prices. These prices are generally adjusted based on indices. Quantities sold under some of these contracts may vary from year to year within certain limits at the option of the customer. The Company sold approximately 140.8 million tons of coal in 2012. Approximately 70% of this tonnage (representing approximately 50% of the Company's revenue) was sold under long-term contracts (contracts having a term of greater than one year). Long-term contracts range in remaining life from one to eight years.

Third-party sources of coal

The Company uses independent contractors to mine coal at certain mining complexes. The Company also purchases coal from third parties that it sells to customers. Factors beyond the Company's control could affect the availability of coal produced for or purchased by the Company. Disruptions in the quantities of coal produced for or purchased by the Company could impair its ability to fill customer orders or require it to purchase coal from other sources at prevailing market prices in order to satisfy those orders.

Transportation

The Company depends upon barge, rail, truck and belt transportation systems to deliver coal to its customers. Disruption of these transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks, and other events could temporarily impair the Company's ability to supply coal to its customers, resulting in decreased shipments. In the past, disruptions in rail service have resulted in missed shipments and production interruptions.

20. Earnings (Loss) Per Common Share

The following table provides the basis for earnings (loss) per share calculations by reconciling basic and diluted weighted average shares outstanding:

	Year Ended December 31		
	2012	2011	2010
	(In thousands)		
Weighted average shares outstanding:			
Basic weighted average shares outstanding	211,381	190,086	162,398
Effect of common stock equivalents under incentive plans	—	819	812
Diluted weighted average shares outstanding	211,381	190,905	163,210

The effect of options to purchase 4.9 million, 2.6 million and 2.5 million shares of common stock were excluded from the calculation of diluted weighted average shares outstanding for the years ended December 31, 2012, 2011 and 2010, respectively, because the exercise price of these options exceeded the average market price of the Company's common stock for this period. The weighted average share impact of options, restricted stock and restricted stock units that were excluded from the calculation of weighted average shares for the year ended December 31, 2012 due to the Company's net loss were not significant.

21. Leases

The Company leases equipment, land and various other properties under non-cancelable long-term leases, expiring at various dates. Certain leases contain options that would allow the Company to extend the lease or purchase the leased asset at the end of the base lease term. In addition, the Company enters into various non-cancelable royalty lease agreements under which future minimum payments are due.

Minimum payments due in future years under these agreements in effect at December 31, 2012 are as follows:

	Operating Leases	Royalties
	(In thousands)	
2013	$ 26,837	$ 26,303
2014	25,109	35,954
2015	17,748	37,725
2016	9,708	33,833
2017	7,306	32,690
Thereafter	5,334	147,103
	$ 92,042	$ 313,608

Rental expense, including amounts related to these operating leases and other shorter-term arrangements, amounted to $41.2 million in 2012, $43.9 million in 2011 and $41.6 million in 2010.

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Royalties are paid to lessors either as a fixed price per ton or as a percentage of the gross selling price of the mined coal. Royalties under the majority of the Company's significant leases are paid on the percentage of gross selling price basis. Royalty expense, including production royalties, was $302.0 million in 2012, $349.0 million in 2011 and $286.8 million in 2010.

As of December 31, 2012, certain of the Company's lease obligations were secured by outstanding surety bonds totaling $60.7 million.

22. Transactions with Patriot Coal Corporation

On December 31, 2005, Arch entered into a purchase and sale agreement to sell mining complexes to Magnum Coal Company ("Magnum"). On July 23, 2008, Patriot Coal Corporation acquired Magnum from Arc Light Capital Partners. On July 9, 2012, Patriot Coal Corporation and certain of its wholly owned subsidiaries, including Magnum, (collectively, "Patriot") filed voluntary petitions for reorganization under Chapter 11 of the U.S. Code in the U.S. Bankruptcy Court for the Southern District of New York ("Bankruptcy Court").

The Company has agreed to continue to provide surety bonds and letters of credit for certain Magnum obligations, primarily reclamation. The surety bonding amounts are mandated by the state and are not directly related to the estimated cost to reclaim the properties. At December 31, 2012, the Company had $34.4 million of surety bonds remaining related to Magnum properties, however Patriot Coal has posted letters of credit of $16.7 million in the Company's favor.

On September 20, 2012, Patriot filed a motion with the Bankruptcy Court to reject a master coal sales agreement entered into on December 31, 2005 between the Company and Magnum, which was established in order to meet obligations under a coal sales agreement with a customer who did not consent to the assignment of their contract to Magnum. On December 18, 2012, the court accepted Patriot's motion to reject the master coal sales agreement. As a result of the court's decision, the Company accrued $58.3 million, which represents the discounted cash flows of the remaining monthly buyout amounts under the underlying coal sales agreement. The current liability for this obligation was $7.6 million at December 31, 2012.

23. Commitments and Contingencies

Allegheny Energy Supply ("Allegheny"), the sole customer of coal produced at the Company's subsidiary Wolf Run Mining Company's ("Wolf Run") Sycamore No. 2 mine, filed a lawsuit against Wolf Run, Hunter Ridge Holdings, Inc. ("Hunter Ridge"), and ICG in state court in Allegheny County, Pennsylvania on December 28, 2006, and amended its complaint on April 23, 2007. Allegheny claimed that Wolf Run breached a coal supply contract when it declared force majeure under the contract upon idling the Sycamore No. 2 mine in the third quarter of 2006, and that Wolf Run continued to breach the contract by failing to ship in volumes referenced in the contract. The Sycamore No. 2 mine was idled after encountering adverse geologic conditions and abandoned gas wells that were previously unidentified and unmapped. After extensive searching for gas wells and rehabilitation of the mine, it was re-opened in 2007, but with notice to Allegheny that it would necessarily operate at reduced volumes in order to safely and effectively avoid the many gas wells within the reserve. The amended complaint also alleged that the production stoppages constitute a breach of the guarantee agreement by Hunter Ridge and breach of certain representations made upon entering into the contract in early 2005. Allegheny voluntarily dropped the breach of representation claims later. Allegheny claimed that it would incur costs in excess of $100 million to purchase replacement coal over the life of the contract. ICG, Wolf Run and Hunter Ridge answered the amended complaint on August 13, 2007, disputing all of the remaining claims.

On November 3, 2008, ICG, Wolf Run and Hunter Ridge filed an amended answer and counterclaim against the plaintiffs seeking to void the coal supply agreement due to, among other things, fraudulent inducement and

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Notes to Consolidated Financial Statements (Continued)

conspiracy. On September 23, 2009, Allegheny filed a second amended complaint alleging several alternative theories of liability in its effort to extend contractual liability to ICG, which was not a party to the original contract and did not exist at the time Wolf Run and Allegheny entered into the contract. No new substantive claims were asserted. ICG answered the second amended complaint on October 13, 2009, denying all of the new claims. ICG's counterclaim was dismissed on motion for summary judgment entered on May 11, 2010. Allegheny's claims against ICG were also dismissed by summary judgment, but the claims against Wolf Run and Hunter Ridge were not. The court conducted a non-jury trial of this matter beginning on January 10, 2011 and concluding on February 1, 2011. At the trial, Allegheny presented its evidence for breach of contract and claimed that it is entitled to past and future damages in the aggregate of between $228.0 million and $377.0 million. Wolf Run and Hunter Ridge presented their defense of the claims, including evidence with respect to the existence of force majeure conditions and excuse under the contract and applicable law. Wolf Run and Hunter Ridge presented evidence that Allegheny's damage calculations were significantly inflated because they were not determined as of the time of the breach and, in some instances, artificially assumed future non-delivery or did not take into account the apparent requirement to supply coal in the future. On May 2, 2011, the trial court entered a Memorandum and Verdict determining that Wolf Run had breached the coal supply contract and that the performance shortfall was not excused by force majeure. ICG and Allegheny filed post-verdict motions in the trial court and on August 23, 2011, the court denied the parties' motions. The court entered a final judgment on August 25, 2011, in the amount of $104.1 million, which included pre-judgment interest. The parties appealed the lower court's decision to the Superior Court of Pennsylvania. Wolf Run and Hunter Ridge have filed an appeal bond in the amount of $124.9 million. On August 13, 2012, the Superior Court of Pennsylvania ruled that the lower court should have calculated damages as of the date of breach, and remanded the matter back to the lower court with instructions to recalculate the award. This ruling resulted in a reduction of the Company's best estimate of the probable loss related to this lawsuit. On November 19, 2012, Allegheny filed a Petition for Allowance of Appeal with the Supreme Court of Pennsylvania and Wolf Run and Hunter Ridge filed an Answer. This Petition is pending.

In addition, the Company is a party to numerous claims and lawsuits with respect to various matters. The Company provides for costs related to contingencies when a loss is probable and the amount is reasonably determinable. As of December 31, 2012 and December 31, 2011, the Company had accrued $32.8 million and $117.2 million, respectively, for all legal matters, including $4.4 million and $6.3 million classified as current. The ultimate resolution of any such legal matter could result in outcomes which may be materially different from amounts the Company has accrued for such matters.

The Company has unconditional purchase obligations relating to purchases of coal, materials and supplies and capital commitments, other than reserve acquisitions, and is also a party to transportation capacity commitments. The future commitments under these agreements total $216.2 million in 2013, $135.3 million in 2014, $135.1 million in 2015, $102.5 million in 2016, $98.6 million in 2017 and $445.6 million thereafter. During the years ended December 31, 2012, 2011 and 2010, the Company fulfilled its commitments under agreements containing unconditional obligations.

24. Segment Information

The Company has three reportable business segments, which are based on the major coal producing basins in which the Company operates. Each of these reportable business segments includes a number of mine complexes. The Company manages its coal sales by coal basin, not by individual mine complex. Geology, coal transportation routes to customers, regulatory environments and coal quality are characteristic to a basin. Accordingly, market and contract pricing have developed by coal basin. Mine operations are evaluated based on their per-ton operating costs (defined as including all mining costs but excluding pass-through transportation expenses), as well as on other non-financial measures, such as safety and environmental performance. The Company's reportable segments are the

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Powder River Basin (PRB) segment, with operations in Wyoming; the Western Bituminous (WBIT) segment, with operations in Utah, Colorado and southern Wyoming; the Appalachia (APP) segment, with operations in West Virginia, Kentucky, Maryland and Virginia. The "Other" operating segment represents primarily the Company's Illinois operations and ADDCAR subsidiary, which manufactures and sells its patented highwall mining system.

Operating segment results for the years ended December 31, 2012, 2011 and 2010 are presented below. Results for the reportable segments include all direct costs of mining, including all depreciation, depletion and amortization related to the mining operations, even if the assets are not recorded at the operating segment level. These reportable segments results do not reflect mine closure or impairment costs, since those are not reflected in the operating income reviewed by management. Corporate, Other and Eliminations includes these charges, as well as the change in fair value of coal derivatives and coal trading activities, net; corporate overhead; land management; other support functions; and the elimination of intercompany transactions.

The asset amounts below represent an allocation of assets consistent with the basis used for the Company's incentive compensation plans. The amounts in Corporate, Other and Eliminations represent primarily corporate assets (cash, receivables, investments, plant, property and equipment) as well as unassigned coal reserves, above-market acquired sales contracts and other unassigned assets. Goodwill is allocated to the respective reporting units, even though it may not be reflected in the subsidiaries' financial statements.

	PRB	APP	WBIT	Other Operating Segments	Corporate, Other and Eliminations	Consolidated
			(in thousands)			
December 31, 2012						
Revenues	$ 1,524,537	$ 1,793,575	$ 728,089	$ 112,837	$ —	$ 4,159,038
Income (loss) from operations	100,679	(606,235)	144,421	5,145	(325,598)	(681,588)
Depreciation, depletion and amortization	166,539	271,220	71,696	11,512	4,541	525,508
Amortization of acquired sales contracts, net	(1,987)	(23,925)	—	723	—	(25,189)
Total assets	1,972,522	3,875,105	658,255	176,032	3,324,863	10,006,777
Capital expenditures	23,410	275,476	58,465	9,928	27,946	395,225
December 31, 2011						
Revenues	$ 1,646,947	$ 1,915,090	$ 672,766	$ 51,092	$ —	$ 4,285,895
Income (loss) from operations	180,730	283,404	119,665	(4,685)	(165,538)	413,576
Depreciation, depletion and amortization	171,693	203,759	81,235	7,876	2,024	466,587
Amortization of acquired sales contracts, net	19,458	(39,988)	—	(1,539)	—	(22,069)
Total assets	2,307,783	4,740,723	681,393	581,040	1,903,020	10,213,959
Capital expenditures	110,999	217,435	66,356	28,243	117,903	540,936
December 31, 2010						
Revenues	$ 1,606,236	$ 1,042,490	$ 537,542	$ —	$ —	$ 3,186,268
Income (loss) from operations	146,555	193,943	58,082	—	(74,596)	323,984
Depreciation, depletion and amortization	185,218	97,764	80,497	—	1,587	365,066
Amortization of acquired sales contracts, net	35,606	—	—	—	—	35,606
Total assets	2,295,786	706,624	677,611	—	1,200,748	4,880,769
Capital expenditures	38,142	70,839	65,470	—	140,206	314,657

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Notes to Consolidated Financial Statements (Continued)

A reconciliation of segment income from operations to consolidated income before income taxes follows:

	December 31 2012	December 31 2011	December 31 2010
	(In thousands)		
Income (loss) from operations	$ (681,588)	$ 413,576	$ 323,984
Interest expense	(317,626)	(230,186)	(142,549)
Interest income	5,478	3,309	2,449
Other nonoperating expense	(23,668)	(51,448)	(6,776)
Income (loss) before income taxes	$ (1,017,404)	$ 135,251	$ 177,108

25. Quarterly Financial Information (Unaudited)

Quarterly financial data for the years ended December 31, 2012 and 2011 is summarized below:

	March 31	June 30 (a)(b)	September 30 (a)	December 31 (b)
	(In thousands, except per share data)			
2012:				
Revenues	1,039,651	1,063,538	1,087,618	968,231
Gross profit	63,704	54,984	69,249	37,176
Mine closure and asset impairment costs	—	525,762	(2,194)	—
Goodwill and other intangible asset impairment	—	115,791	—	230,632
Income from operations	54,081	(588,984)	135,960	(282,645)
Net income (loss)	1,409	(435,424)	45,751	(295,423)
Basic earnings (loss) per common share	$ 0.01	$ (2.05)	$ 0.22	$ (1.39)
Diluted earnings (loss) per common share	$ 0.01	$ (2.05)	$ 0.22	$ (1.39)

	March 31	June 30 (c)	September 30 (c)	December 31 (c)
	(In thousands, except per share data)			
2011:				
Revenues	$ 872,938	$ 985,528	$ 1,198,673	$ 1,228,756
Gross profit	130,523	172,234	120,085	154,388
Income from operations	102,238	95,354	76,256	139,728
Net income	55,874	6,630	9,121	71,215
Basic earnings per common share	$ 0.34	$ 0.04	$ 0.04	$ 0.34
Diluted earnings per common share	$ 0.34	$ 0.04	$ 0.04	$ 0.33

(a) The Company's results in 2012 were impacted by challenging market conditions. In response to these conditions, the Company made the decision to close or idle 10 mines in Appalachia and curtailed production at other thermal mines. See Note 3, "Mine Closure and Asset Impairment Costs".

(b) Challenging markets also resulted in impairment charges to goodwill relating to the Black Thunder mining complex in the second quarter of 2012 and two mines in Appalachia in the fourth quarter of 2012. See Note 7, "Goodwill".

(c) The Company expensed costs related to the June 2011 acquisition of ICG $98.2 million, $4.7 million and $1.3 million in the second, third and fourth quarters of 2011, respectively.

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Notes to Consolidated Financial Statements (Continued)

26. Supplemental Condensed Consolidating Financial Information

Pursuant to the indentures governing Arch Coal, Inc.'s senior notes, certain wholly-owned subsidiaries of the Company have fully and unconditionally guaranteed the senior notes on a joint and several basis. The following tables present condensed consolidating financial information for (i) the Company, (ii) the issuer of the senior notes, (iii) the guarantors under the senior notes, and (iv) the entities which are not guarantors under the senior notes (Arch Receivable Company, LLC and the Company's subsidiaries outside the U.S.):

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Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Operations
Year Ended December 31, 2012

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Revenues	$ —	$ 4,159,038	$ —	$ —	$ 4,159,038
Costs, expenses and other					
Cost of sales	10,918	3,427,095	—	—	3,438,013
Depreciation, depletion and amortization	5,392	520,083	33	—	525,508
Amortization of acquired sales contracts, net	—	(25,189)	—	—	(25,189)
Change in fair value of coal derivatives and coal trading activities, net	—	(16,590)	—	—	(16,590)
Coal derivative settlements, non-hedging	—	(43,990)	—	—	(43,990)
Selling, general and administrative expenses	84,198	41,316	8,785	—	134,299
Contract settlement resulting from Patriot Coal bankruptcy	—	58,335	—	—	58,335
Legal contingencies	—	(79,532)	—	—	(79,532)
Mine closure and asset impairment costs	—	523,568	—	—	523,568
Goodwill and other intangible asset impairment	—	346,423	—	—	346,423
Other operating income, net	(13,391)	9,559	(16,387)	—	(20,219)
	87,117	4,761,078	(7,569)	—	4,840,626
Income from investment in subsidiaries	(569,795)	—	—	569,795	—
Income (loss) from operations	(656,912)	(602,040)	7,569	569,795	(681,588)
Interest expense, net:					
Interest expense	(366,614)	(35,207)	(3,221)	87,416	(317,626)
Interest income	28,097	57,303	7,494	(87,416)	5,478
	(338,517)	22,096	4,273	—	(312,148)
Other nonoperating expense					
Net loss resulting from early retirement and refinancing of debt	(21,975)	(1,693)	—	—	(23,668)
Bridge financing costs related to ICG	—	—	—	—	—
	(21,975)	(1,693)	—	—	(23,668)
Income (loss) before income taxes	(1,017,404)	(581,637)	11,842	569,795	(1,017,404)
Provision for (benefit from) income taxes	(333,717)	—	—	—	(333,717)
Net income (loss)	(683,687)	(581,637)	11,842	569,795	(683,687)
Less: Net income attributable to noncontrolling interest	(268)	—	—	—	(268)
Net income (loss) attributable to Arch Coal, Inc.	$ (683,955)	$ (581,637)	$ 11,842	$ 569,795	$ (683,955)
Total comprehensive income (loss)	$ (692,239)	$ (585,033)	$ 9,259	$ 575,774	$ (692,239)

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Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Operations
Year Ended December 31, 2011

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Revenues	$ —	$ 4,285,895	$ —	$ —	$ 4,285,895
Costs, expenses and other					
Cost of sales	22,926	3,244,984	—	—	3,267,910
Depreciation, depletion and amortization	2,876	463,711	—	—	466,587
Amortization of acquired sales contracts, net	—	(22,069)	—	—	(22,069)
Change in fair value of coal derivatives and coal trading activities, net	—	(2,907)	—	—	(2,907)
Coal derivative settlements, non-hedging	—	7	—	—	7
Selling, general and administrative expenses	74,589	40,940	3,527	—	119,056
Mine closure and asset impairment costs	7,316	—	—	—	7,316
Acquisition and transition costs	47,360	—	—	—	47,360
Other operating income, net	(23,306)	12,615	(250)	—	(10,941)
	131,761	3,737,281	3,277	—	3,872,319
Income from investment in subsidiaries	556,442	—	—	(556,442)	—
Income (loss) from operations	424,681	548,614	(3,277)	(556,442)	413,576
Interest expense, net:					
Interest expense	(256,221)	(46,565)	(2,224)	74,824	(230,186)
Interest income	16,281	55,072	6,780	(74,824)	3,309
	(239,940)	8,507	4,556	—	(226,877)
Other nonoperating expense					
Net loss resulting from early retirement and refinancing of debt	—	(1,958)	—	—	(1,958)
Bridge financing costs related to ICG	(49,490)	—	—	—	(49,490)
	(49,490)	(1,958)	—	—	(51,448)
Income (loss) before income taxes	135,251	555,163	1,279	(556,442)	135,251
Provision for (benefit from) income taxes	(7,589)	—	—	—	(7,589)
Net income (loss)	142,840	555,163	1,279	(556,442)	142,840
Less: Net income attributable to noncontrolling interest	(1,157)	—	—	—	(1,157)
Net income (loss) attributable to Arch Coal, Inc.	$ 141,683	$ 555,163	$ 1,279	$ (556,442)	$ 141,683
Total comprehensive income (loss)	$ 141,240	$ 552,663	$ 1,279	$ (553,942)	$ 141,240

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Operations
Year Ended December 31, 2010

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Revenues	$ —	$ 3,186,268	$ —	$ —	$ 3,186,268
Costs, expenses and other					
Cost of sales	11,523	2,384,289	—	—	2,395,812
Depreciation, depletion and amortization	2,933	362,133	—	—	365,066
Amortization of acquired sales contracts, net	—	35,606	—	—	35,606
Change in fair value of coal derivatives and coal trading activities, net	—	8,924	—	—	8,924
Coal derivative settlements, non-hedging	—	(4,542)	—	—	(4,542)
Selling, general and administrative expenses	79,580	36,091	2,506	—	118,177
Gain on Knight Hawk transaction	—	(41,577)	—	—	(41,577)
Other operating income, net	(10,258)	(4,924)	—	—	(15,182)
	83,778	2,776,000	2,506	—	2,862,284
Income from investment in subsidiaries	393,363	—	—	(393,363)	—
Income (loss) from operations	309,585	410,268	(2,506)	(393,363)	323,984
Interest expense, net:					
Interest expense	(143,606)	(64,377)	(2,849)	68,283	(142,549)
Interest income	11,129	52,899	6,704	(68,283)	2,449
	(132,477)	(11,478)	3,855	—	(140,100)
Other nonoperating expense					
Net loss resulting from early retirement and refinancing of debt	—	(6,776)	—	—	(6,776)
Bridge financing costs related to ICG	—	—	—	—	—
	—	(6,776)	—	—	(6,776)
Income (loss) before income taxes	177,108	392,014	1,349	(393,363)	177,108
Provision for (benefit from) income taxes	17,714	—	—	—	17,714
Net income (loss)	159,394	392,014	1,349	(393,363)	159,394
Less: Net income attributable to noncontrolling interest	(537)	—	—	—	(537)
Net income (loss) attributable to Arch Coal, Inc.	$ 158,857	$ 392,014	$ 1,349	$ (393,363)	$ 158,857
Total comprehensive income (loss)	$ 172,885	$ 400,664	$ 1,349	$ (402,013)	$ 172,885

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Balance Sheets
December 31, 2012

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (In thousands)	Eliminations	Consolidated
Assets					
Cash and cash equivalents	$ 671,313	$ 100,468	$ 12,841	$ —	$ 784,622
Restricted cash	3,453	—	—	—	3,453
Short term investments	234,305	—	—	—	234,305
Receivables	49,281	40,452	247,171	(4,824)	332,080
Inventories	—	365,424	—	—	365,424
Other	106,786	86,877	557	—	194,220
Total current assets	1,065,138	593,221	260,569	(4,824)	1,914,104
Property, plant and equipment, net	27,476	7,309,550	72	—	7,337,098
Investment in subsidiaries	8,254,508	—	—	(8,254,508)	—
Intercompany receivables	(1,367,739)	1,600,311	(232,572)	—	—
Note receivable from Arch Western	675,000	—	—	(675,000)	—
Other	187,171	568,314	90	—	755,575
Total other assets	7,748,940	2,168,625	(232,482)	(8,929,508)	755,575
Total assets	$ 8,841,554	$ 10,071,396	$ 28,159	$ (8,934,332)	$ 10,006,777
Liabilities and Stockholders' Equity					
Accounts payable	$ 19,859	$ 204,370	$ 189	$ —	$ 224,418
Accrued expenses and other current liabilities	65,293	259,162	124	(4,824)	319,755
Current maturities of debt and short-term borrowings	32,054	842	—	—	32,896
Total current liabilities	117,206	464,374	313	(4,824)	577,069
Long-term debt	5,061,925	23,954	—	—	5,085,879
Note payable to Arch Coal	—	675,000	—	(675,000)	—
Asset retirement obligations	1,646	408,059	—	—	409,705
Accrued pension benefits	33,456	34,174	—	—	67,630
Accrued postretirement benefits other than pension	13,953	31,133	—	—	45,086
Accrued workers' compensation	25,323	56,306	—	—	81,629
Deferred income taxes	664,182	—	—	—	664,182
Other noncurrent liabilities	69,296	151,360	374	—	221,030
Total liabilities	5,986,987	1,844,360	687	(679,824)	7,152,210
Stockholders' equity	2,854,567	8,227,036	27,472	(8,254,508)	2,854,567
Total liabilities and stockholders' equity	$ 8,841,554	$ 10,071,396	$ 28,159	$ (8,934,332)	$ 10,006,777

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Balance Sheets
December 31, 2011

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Assets					
Cash and cash equivalents	$ 61,375	$ 75,425	$ 1,349	$ —	$ 138,149
Restricted cash	10,322	—	—	—	10,322
Short term investments	—	—	—	—	—
Receivables	65,187	27,001	378,608	(1,617)	469,179
Inventories	—	377,490	—	—	377,490
Other	81,732	105,282	620	—	187,634
Total current assets	218,616	585,198	380,577	(1,617)	1,182,774
Property, plant and equipment, net	21,241	7,918,816	9,093	—	7,949,150
Investment in subsidiaries	8,813,080	—	—	(8,813,080)	—
Intercompany receivables	(1,190,342)	1,448,902	(258,560)	—	—
Note receivable from Arch Western	225,000	—	—	(225,000)	—
Other	(85,668)	1,167,501	202	—	1,082,035
Total other assets	7,762,070	2,616,403	(258,358)	(9,038,080)	1,082,035
Total assets	$ 8,001,927	$ 11,120,417	$ 131,312	$ (9,039,697)	$ 10,213,959
Liabilities and Stockholders' Equity					
Accounts payable	$ 30,576	$ 353,180	$ 26	$ —	$ 383,782
Accrued expenses and other current liabilities	75,121	282,446	85	(1,617)	356,035
Current maturities of debt and short-term borrowings	172,564	1,987	106,300	—	280,851
Total current liabilities	278,261	637,613	106,411	(1,617)	1,020,668
Long-term debt	3,308,674	453,623	—	—	3,762,297
Note payable to Arch Coal	—	225,000	—	(225,000)	—
Asset retirement obligations	877	445,907	—	—	446,784
Accrued pension benefits	19,198	29,046	—	—	48,244
Accrued postretirement benefits other than pension	13,843	28,466	—	—	42,309
Accrued workers' compensation	17,272	54,676	—	—	71,948
Deferred income taxes	621,483	355,270	—	—	976,753
Other noncurrent liabilities	152,745	102,553	84	—	255,382
Total liabilities	4,412,353	2,332,154	106,495	(226,617)	6,624,385
Redeemable noncontrolling interest	11,534	—	—	—	11,534
Stockholders' equity	3,578,040	8,788,263	24,817	(8,813,080)	3,578,040
Total liabilities and stockholders' equity	$ 8,001,927	$ 11,120,417	$ 131,312	$ (9,039,697)	$ 10,213,959

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2012

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$ (571,576)	$ 781,551	$ 122,829	$ —	$ 332,804
Investing Activities					
Change in restricted cash	6,869	—	—	—	6,869
Capital expenditures	(4,424)	(390,801)	—	—	(395,225)
Proceeds from dispositions of property, plant and equipment	—	1,328	21,497	—	22,825
Investments in and advances to affiliates	(6,287)	(13,134)	—	1,663	(17,758)
Purchases of short term investments	(236,862)	—	—	—	(236,862)
Proceeds from sales of short term investments	1,754	—	—	—	1,754
Purchase of noncontrolling interest	(17,500)	—	—	—	(17,500)
Additions to prepaid royalties	—	(13,269)	—	—	(13,269)
Cash provided by (used in) investing activities	(256,450)	(415,876)	21,497	1,663	(649,166)
Financing Activities					
Contributions from parent	—	1,663	—	(1,663)	—
Proceeds from the issuance of senior notes	359,753	—	—	—	359,753
Proceeds from term note issuance	1,633,500	—	—	—	1,633,500
Payments to retire debt	—	(452,934)	—	—	(452,934)
Net decrease in borrowings under lines of credit and commercial paper program	(375,000)	—	(106,300)	—	(481,300)
Payments on term note	(7,625)	—	—	—	(7,625)
Net payments on other debt	(682)	—	—	—	(682)
Debt financing costs	(50,022)	—	(546)	—	(50,568)
Dividends paid	(42,440)	—	—	—	(42,440)
Issuance of common stock under incentive plans	5,131	—	—	—	5,131
Transactions with affiliates, net	(84,651)	110,639	(25,988)	—	—
Cash provided by (used in) financing activities	1,437,964	(340,632)	(132,834)	(1,663)	962,835
Increase in cash and cash equivalents	609,938	25,043	11,492	—	646,473
Cash and cash equivalents, beginning of period	61,375	75,425	1,349	—	138,149
Cash and cash equivalents, end of period	$ 671,313	$ 100,468	$ 12,841	$ —	$ 784,622

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2011

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$ (187,039)	$ 998,082	$ (168,801)	$ —	$ 642,242
Investing Activities					
Acquisition of ICG, net of cash acquired	(2,894,339)	—	—	—	(2,894,339)
Change in restricted cash	5,167	—	—	—	5,167
Capital expenditures	(12,809)	(528,021)	(106)	—	(540,936)
Proceeds from dispositions of property, plant and equipment	—	25,887	—	—	25,887
Investments in and advances to affiliates	(633,534)	(33,553)	—	605,178	(61,909)
Additions to prepaid royalties	—	(29,957)	—	—	(29,957)
Consideration paid related to prior business acquisition	(829)	—	—	—	(829)
Cash provided by (used in) investing activities	(3,536,344)	(565,644)	(106)	605,178	(3,496,916)
Financing Activities					
Contributions from parent	—	605,178	—	(605,178)	—
Proceeds from the issuance of senior notes	2,000,000	—	—	—	2,000,000
Proceeds from the issuance of common stock, net	1,267,933	—	—	—	1,267,933
Payments to retire debt	—	(605,178)	—	—	(605,178)
Net decrease in borrowings under lines of credit and commercial paper program	375,000	(56,904)	106,300	—	424,396
Net proceeds from other debt	5,334	—	—	—	5,334
Debt financing costs	(114,799)	(16)	(8)	—	(114,823)
Dividends paid	(80,748)	—	—	—	(80,748)
Issuance of common stock under incentive plans	2,316	—	—	—	2,316
Transactions with affiliates, net	316,009	(379,973)	63,964	—	—
Cash provided by (used in) financing activities	3,771,045	(436,893)	170,256	(605,178)	2,899,230
Increase (decrease) in cash and cash equivalents	47,662	(4,455)	1,349	—	44,556
Cash and cash equivalents, beginning of period	13,713	79,880	—	—	93,593
Cash and cash equivalents, end of period	$ 61,375	$ 75,425	$ 1,349	$ —	$ 138,149

Arch Coal, Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Statements of Cash Flows
Year Ended December 31, 2010

	Parent/Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Cash provided by (used in) operating activities	$ (230,966)	$ 943,361	$ (15,248)	$ —	$ 697,147
Investing Activities					
Capital expenditures	(4,814)	(309,843)	—	—	(314,657)
Proceeds from dispositions of property, plant and equipment	—	330	—	—	330
Investments in and advances to affiliates	(13,821)	(32,364)	—	—	(46,185)
Additions to prepaid royalties	—	(27,355)	—	—	(27,355)
Consideration paid related to prior business acquisition	(1,262)	—	—	—	(1,262)
Cash used in investing activities	(19,897)	(369,232)	—	—	(389,129)
Financing Activities					
Proceeds from the issuance of senior notes	500,000	—	—	—	500,000
Payments to retire debt	—	(505,627)	—	—	(505,627)
Net decrease in borrowings under lines of credit and commercial paper program	(120,000)	7,451	(84,000)	—	(196,549)
Net proceeds from other debt	82	—	—	—	82
Debt financing costs	(12,022)	(390)	(339)	—	(12,751)
Dividends paid	(63,373)	—	—	—	(63,373)
Issuance of common stock under incentive plans	1,764	—	—	—	1,764
Contribution from non-controlling interest	891	—	—	—	891
Transactions with affiliates, net	(97,021)	(2,566)	99,587	—	—
Cash provided by (used in) financing activities	210,321	(501,132)	15,248	—	(275,563)
Increase (decrease) in cash and cash equivalents	(40,542)	72,997	—	—	32,455
Cash and cash equivalents, beginning of period	54,255	6,883	—	—	61,138
Cash and cash equivalents, end of period	$ 13,713	$ 79,880	$ —	$ —	$ 93,593

Schedule II

Arch Coal, Inc. and Subsidiaries
Valuation and Qualifying Accounts

	Balance at Beginning of Year	Additions (Reductions) Charged to Costs and Expenses	Charged to Other Accounts	Deductions[(a)]	Balance at End of Year
			(In thousands)		
Year ended December 31, 2012					
Reserves deducted from asset accounts:					
Other assets — other notes and accounts receivable	$ 17	$ 1,039	$ —	$ 13	$ 1,043
Current assets — supplies and inventory	13,107	1,961	—	2,479	12,589
Deferred income taxes	2,831	31,832	—	—	34,663
Year ended December 31, 2011					
Reserves deducted from asset accounts:					
Other assets — other notes and accounts receivable	$ —	$ 17	$ —	$ —	$ 17
Current assets — supplies and inventory	12,701	1,755	—	1,349	13,107
Deferred income taxes	737	2,416	—	322	2,831
Year ended December 31, 2010					
Reserves deducted from asset accounts:					
Other assets — other notes and accounts receivable	$ 109	$ —	$ —	$ 109	$ —
Current assets — supplies and inventory	13,406	1,962	—	2,667	12,701
Deferred income taxes	1,120	(383)	—	—	737

(a) Reserves utilized, unless otherwise indicated.

Exhibit 10.45

EXECUTION COPY

[ARCH COAL]

FIFTH AMENDMENT TO AMENDED AND
RESTATED RECEIVABLES PURCHASE AGREEMENT

THIS FIFTH AMENDMENT TO AMENDED AND RESTATED RECEIVABLES PURCHASE AGREEMENT (this "Amendment"), dated as of December 11, 2012, is entered into among ARCH RECEIVABLE COMPANY, LLC (the "Seller"), ARCH COAL SALES COMPANY, INC. (the "Servicer"), the various financial institutions party to the Agreement (as defined below) as Conduit Purchasers (the "Conduit Purchasers"), as Related Committed Purchasers (the "Related Committed Purchasers"), as LC Participants (the "LC Participants"), and as Purchaser Agents (the "Purchaser Agents"), and PNC BANK, NATIONAL ASSOCIATION ("PNC"), as Administrator (the "Administrator") and as LC Bank (the "LC Bank"; together with the Conduit Purchasers, the Related Committed Purchasers and the LC Participants, the "Purchasers").

RECITALS

1. The parties hereto are parties to the Amended and Restated Receivables Purchase Agreement, dated as of February 24, 2010 (as amended, restated, supplemented or otherwise modified through the date hereof, the "Agreement").

2. Concurrently herewith, the Seller, the Servicer, ACI, the Administrator, Market Street and PNC are entering into that certain Fourth Amended and Restated Purchaser Group Fee Letter (the "Market Street Fee Letter"), dated as of the date hereof.

3. Concurrently herewith, the Seller, the Servicer, ACI, Atlantic and Credit Agricole are entering into that certain Third Amended and Restated Purchaser Group Fee Letter (the "Atlantic Fee Letter"; together with the Market Street Fee Letter, collectively, the "Fee Letters"), dated as of the date hereof.

4. The parties hereto are parties to that certain Fourth Amendment to Amended and Restated Receivables Purchase Agreement, dated as of December 13, 2011 (the "Fourth Amendment").

5. The parties hereto desire to amend the Agreement as hereinafter set forth.

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

SECTION 1. *Certain Defined Terms*. Capitalized terms that are used but not defined herein shall have the meanings set forth in the Agreement.

SECTION 2. *Amendments to the Agreement*. The Agreement is hereby amended as follows:

(a) Each of (i) the defined terms added to the Agreement pursuant to Section 1 of the Fourth Amendment and (ii) the amendments to the Agreement set forth in Section 3 of the Fourth Amendment, in each case, are hereby deleted from the Agreement and shall be of no further force or effect.

(b) Subclause (i) of Section 3.1 of the Agreement is hereby amended by adding the phrase "or any Interim Report" immediately following the term "Information Package" where it appears therein.

(c) Subclause (ii) of Section 3.1 of the Agreement is hereby amended by adding the phrase ", any Interim Report" immediately following the term "Information Package" where it appears therein.

(d) Section 3.2 of the Agreement is hereby amended by adding the phrase "or any Interim Report" immediately following the term "Information Package" where it appears therein.

(e) The following new defined terms are hereby added to Exhibit I to the Agreement in appropriate alphabetical order:

"Daily Report" has the meaning set forth in Section 1(a)(ii) of Exhibit IV to the Agreement.

"Interim Report" means each Daily Report and Weekly Report.

"Liquidity" has the meaning set forth in the Credit Agreement.

"Weekly Report" has the meaning set forth in Section 1(a)(ii) of Exhibit IV to the Agreement.

(f) The definition of "Credit Agreement" set forth in Exhibit I to the Agreement is hereby replaced in its entirety with the following:

"Credit Agreement" means that certain Amended and Restated Credit Agreement, dated as of June 14, 2011, by and among ACI, the lenders party thereto, PNC, as administrative agent, Bank of America, N.A., The Royal Bank of Scotland PLC and Citibank, N.A., as co-documentation agents, and PNC Capital Markets LLC and Morgan Stanley & Co., Inc., as joint lead arrangers and joint bookrunners, as amended through December 11, 2012 and without giving effect to any termination thereof or any further amendments, supplements or other modifications thereto.

(g) The definition of "Dilution Reserve Percentage" set forth in Exhibit I to the Agreement is hereby amended by replacing the number "2.25" where it appears therein with the number "2.5".

(h) Clause (c) of the definition of "Eligible Receivable" set forth in Exhibit I to the Agreement is hereby amended by replacing the number "60" where it appears therein with the number "90".

(i) Clause (a) of the definition of "Facility Termination Date" set forth in Exhibit I to the Agreement is hereby amended by replacing the date "May 22, 2013" where it appears therein with the date "December 10, 2015".

(j) The definition of "Loss Reserve Percentage" set forth in Exhibit I to the Agreement is hereby amended by replacing the number "2.25" where it appears therein with the number "2.5".

(k) The definition of "Scheduled Commitment Termination Date" set forth in Exhibit I to the Agreement is amended by replacing the date "December 11, 2012" where it appears therein with the date "December 10, 2013".

(l) The definition of "Transaction Documents" set forth in Exhibit I to the Agreement is hereby amended by adding the phrase "Information Packages, Interim Reports," immediately prior to the phrase "other certificates" where it appears therein.

(m) Section 5 of Exhibit III to the Agreement is hereby amended by adding the phrase ", Interim Report" immediately following the term "Information Package" where it appears therein.

(n) Section 1(a)(ii) of Exhibit IV to the Agreement is hereby replaced in its entirety with the following:

(ii) Reports. (A) As soon as available and in any event not later than two Business Days prior to the Monthly Settlement Date, an Information Package as of the most recently completed calendar month, (B) if at any time the Purchased Interest is greater than 50.00%, if requested by the Agent or any Purchaser Agent, a report substantially in the form of Annex H (each, a "Weekly Report") no later than the second Business Day of each calendar week as of the most recently completed calendar week, and (C) if at any time both (I) the Purchased Interest is greater than 50.00% and (II) Liquidity is less than $450,000,000, if requested by the Agent or any Purchaser Agent, a report substantially in the form of Annex I (each, a "Daily Report") on each Business Day as of date that is one Business Day prior to such date.

(o) Section 2(a)(ii) of Exhibit IV to the Agreement is hereby replaced in its entirety with the following:

(ii) Reports. (A) As soon as available and in any event not later than two Business Days prior to the Monthly Settlement Date, an Information Package as of the most recently completed calendar month, (B) if at any time the Purchased Interest is greater than 50.00%, if requested by the Agent or any Purchaser Agent, a Weekly Report no later

than the second Business Day of each calendar week as of the most recently completed calendar week and (C) if at any time both (I) the Purchased Interest is greater than 50.00% and (II) Liquidity is less than $450,000,000, if requested by the Agent or any Purchaser Agent, a Daily Report on each Business Day as of date that is one Business Day prior to such date.

(p) Clause (d) of Exhibit V to the Agreement is hereby replaced in its entirety with the following:

(d) the Seller or the Servicer shall fail to deliver any Information Package or Interim Report pursuant to the Agreement, and such failure shall remain unremedied for two Business Days;

(q) Schedule IV to the Agreement is hereby replaced in its entirety with Exhibit A attached hereto.

(r) New Annex H is hereby added to the Agreement in the form of Exhibit B attached hereto.

(s) New Annex I is hereby added to the Agreement in the form of Exhibit C attached hereto.

SECTION 3. *Commitments; LC Participation Amount*. Each of the parties hereto hereby acknowledges and agrees that after giving effect to the amendments set forth in Section 2 above:

(a) the Commitment of each Purchaser as of the date hereof shall be the applicable amount set forth on Exhibit A attached hereto with respect to such Purchaser;

(b) the LC Participation Amount shall be $80,420,083 as of the date hereof;

(c) Credit Agricole's Pro Rata Share of the LC Participation Amount as of the date hereof shall be $32,168,033.20; and

(d) PNC's Pro Rata Share of the LC Participation Amount as of the date hereof shall be $48,252,049.80.

SECTION 4. *Representations and Warranties*. Each of the Seller and the Servicer hereby represents and warrants to the Administrator, the Purchaser Agents and the Purchasers as follows:

(a) Representations and Warranties. The representations and warranties made by such Person in the Agreement and each of the other Transaction Documents are true and correct as of the date hereof (unless stated to relate solely to an earlier date, in which case such representations or warranties were true and correct as of such earlier date).

(b) Enforceability. The execution and delivery by such Person of this Amendment, and the performance of each of its obligations under this Amendment and

the Agreement, as amended hereby, are within each of its organizational powers and have been duly authorized by all necessary action on its part. This Amendment and the Agreement, as amended hereby, are such Person's valid and legally binding obligations, enforceable in accordance with their respective terms.

(c) No Default. Both before and immediately after giving effect to this Amendment and the transactions contemplated hereby, no Termination Event or Unmatured Termination Event exists or shall exist.

SECTION 5. *Effect of Amendment; Ratification*. All provisions of the Agreement, as expressly amended and modified by this Amendment, shall remain in full force and effect. After this Amendment becomes effective, all references in the Agreement (or in any other Transaction Document) to "the Receivables Purchase Agreement", "this Agreement", "hereof", "herein" or words of similar effect, in each case referring to the Agreement shall be deemed to be references to the Agreement as amended by this Amendment. This Amendment shall not be deemed, either expressly or impliedly, to waive, amend or supplement any provision of the Agreement other than as specifically set forth herein. The Agreement, as amended by this Amendment, is hereby ratified and confirmed in all respects.

SECTION 6. *Effectiveness*. This Amendment shall become effective as of the date hereof, upon (I) receipt by the Administrator of duly executed counterparts of each of (a) this Amendment, (b) the Market Street Fee Letter and (c) the Atlantic Fee Letter and (II) payment by Seller of all fees payable on the date hereof under (and in accordance with) each of the Fee Letters.

SECTION 7. *Counterparts*. This Amendment may be executed in any number of counterparts and by different parties on separate counterparts, each of which when so executed shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by facsimile or electronic transmission shall be effective as delivery of a manually executed counterpart hereof.

SECTION 8. *Governing Law*. This Amendment shall be governed by, and construed in accordance with, the internal laws of the State of New York (including for such purposes Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York).

SECTION 9. *Section Headings*. The various headings of this Amendment are included for convenience only and shall not affect the meaning or interpretation of this Amendment, the Agreement or any provision hereof or thereof.

SECTION 10. Successors and Assigns. This Amendment shall be binding upon and shall inure to the benefit of the parties hereto and their respective successors and permitted assigns.

SECTION 11. Ratification. After giving effect to this Amendment and the transactions contemplated by this Amendment, all of the provisions of the Performance Guaranty shall remain in full force and effect and the Performance Guarantor hereby ratifies and affirms the Performance Guaranty and acknowledges that the Performance Guaranty has continued and shall continue in full force and effect in accordance with its terms.

[SIGNATURES BEGIN ON NEXT PAGE]

IN WITNESS WHEREOF, the parties have executed this Amendment as of the date first written above.

ARCH RECEIVABLE COMPANY, LLC, as Seller

By: /s/ James E. Florczak
Name: James E. Florczak
Title: Vice President & Treasurer

ARCH COAL SALES COMPANY, INC., as Servicer

By: /s/ James E. Florczak
Name: James E. Florczak
Title: Vice President & Treasurer

PNC BANK, NATIONAL ASSOCIATION,
as Administrator

By: /s/ William P. Falcon
Name: William P. Falcon
Title: Vice President

PNC BANK, NATIONAL ASSOCIATION,
as a Purchaser Agent

By: /s/ William P. Falcon
Name: William P. Falcon
Title: Vice President

PNC BANK, NATIONAL ASSOCIATION,
as the LC Bank and as an LC Participant

By: /s/ Mark S. Falcione
Name: Mark S. Falcione
Title: Vice President

MARKET STREET FUNDING LLC,
as a Conduit Purchaser and as a Related Committed Purchaser

By: /s/ Doris J. Hearn
Name: Doris J. Hearn
Title: Vice President

ATLANTIC ASSET SECURITIZATION LLC,
as a Conduit Purchaser

By: /s/ Kostantina Kourmpetis
Name: Kostantina Kourmpetis
Title: Managing Director

By: /s/ Jorge Fries
Name: Jorge Fries

Title: Managing Director

Fifth Amendment to A&R RPA
(Arch Coal)

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK,
as a Related Committed Purchaser and as a Purchaser Agent

By: /s/ Kostantina Kourmpetis
Name: Kostantina Kourmpetis
Title: Managing Director

By: /s/ Jorge Fries
Name: Jorge Fries
Title: Managing Director

Fifth Amendment to A&R RPA
(Arch Coal)

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK,
as an LC Participant

By: /s/ Kostantina Kourmpetis
Name: Kostantina Kourmpetis
Title: Managing Director

By: /s/ Jorge Fries
Name: Jorge Fries
Title: Managing Director

Fifth Amendment to A&R RPA
(Arch Coal)

ACKNOWLEDGED AND AGREED:

ARCH COAL, INC.

By: /s/ James E. Florczak
Name: James E. Florczak
Title: Treasurer

Fifth Amendment to A&R RPA
(Arch Coal)

EXHIBIT A

SCHEDULE IV

GROUP COMMITMENTS

Purchaser Group

Name	Capacity	Commitment	Group Commitment

Market Street Purchaser Group	Purchaser Group		N/A	$	150,000,000
Market Street	Conduit Purchaser		N/A		
Market Street	Related Committed Purchaser	$	150,000,000		
PNC	LC Participant/ LC Bank	$	150,000,000		
PNC	Purchaser Agent		N/A		
Atlantic Purchaser Group	Purchaser Group		N/A	$	100,000,000
Atlantic	Conduit Purchaser		N/A		
Credit Agricole	Related Committed Purchaser	$	100,000,000		
Credit Agricole	LC Participant	$	100,000,000		
Credit Agricole	Purchaser Agent		N/A		

Exhibit 12.1

Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Earnings:					
Pretax income excluding income or loss from equity investments	$ (1,027,419)	$ 123,339	$ 165,534	$ 23,020	$ 395,977
Adjustments:					
Fixed charges	344,042	293,106	153,467	118,075	99,562
Distributed income from equity investments	5,342	19,360	9,917	5,164	2,167
Capitalized interest, net of amortization	19,163	2,113	4,417	3,143	(8,351)
Arch Western Resources, LLC dividends on preferred membership interest	(72)	(91)	(107)	(58)	(107)
Total earnings (loss)	$ (658,944)	$ 437,827	$ 333,228	$ 149,344	$ 489,248
Fixed charges:					
Interest expense	$ 317,626	$ 230,186	$ 142,549	$ 105,932	$ 76,139
Capitalized interest	15,625	1,937	—	824	11,703
Bridge financing costs related to ICG	—	49,490	—	—	—
Arch Western Resources, LLC dividends on preferred membership interest	72	91	107	58	107
Portions of rent which represent an interest factor	10,719	11,402	10,811	11,261	11,613
Total fixed charges	$ 344,042	$ 293,106	$ 153,467	$ 118,075	$ 99,562
Preferred stock dividends	$ —	$ —	$ —	$ —	$ 12
Total fixed charges and preferred stock dividends	$ 344,042	$ 293,106	$ 153,467	$ 118,075	$ 99,574
Ratio of earnings to combined fixed charges and preference dividends	N/A	1.49x	2.17x	1.26x	4.91x

Earnings consist of income from operations before income taxes and are adjusted to include only distributed income from affiliates accounted for on the equity method and fixed charges (excluding capitalized interest). Fixed charges consist of interest incurred on indebtedness, the portion of operating lease rentals deemed representative of the interest factor and the amortization of debt expense.

Exhibit 21.1

Subsidiaries of the Company

The following is a complete list of the direct and indirect subsidiaries of Arch Coal, Inc., a Delaware corporation, including their respective states of incorporation or organization, as of February 28, 2013:

Arch Coal Asia-Pacific PTE. LTD. (Singapore)	**100%**
Arch of Australia PTY LTD (Australia)	**100%**
Arch Coal Australia PTY LTD (Australia)	**100%**
Arch Coal Australia Holdings PTY LTD (Australia)	**100%**
Arch Coal Europe Limited (United Kingdom)	**100%**
Arch Reclamation Services, Inc. (Delaware)	**100%**
Arch Western Acquisition Corporation (Delaware)	**100%**
Arch Western Acquisition, LLC (Delaware)	**100%**
Arch Western Resources, LLC (Delaware)	**0.5%**
Arch Western Resources, LLC (Delaware)	**99.5%**
Arch of Wyoming, LLC (Delaware)	**100%**
Arch Western Finance, LLC (Delaware)	**100%**
Arch Western Bituminous Group, LLC (Delaware)	**100%**
Canyon Fuel Company, LLC (Delaware)	**65%**
Mountain Coal Company, L.L.C. (Delaware)	**100%**
Thunder Basin Coal Company, L.L.C. (Delaware)	**100%**
Triton Coal Company, LLC (Delaware)	**100%**
Ark Land Company (Delaware)	**100%**
Western Energy Resources, Inc. (Delaware)	**100%**
Ark Land KH, Inc. (Delaware)	**100%**
Ark Land LT, Inc. (Delaware)	**100%**
Ark Land WR, Inc. (Delaware)	**100%**
Allegheny Land Company (Delaware)	**100%**
Apogee Holdco, Inc. (Delaware)	**100%**
Arch Coal Sales Company, Inc. (Delaware)	**100%**
Arch Energy Resources, LLC (Delaware)	**100%**
Arch Coal Terminal, Inc. (Delaware)	**100%**
Arch Coal West, LLC (Delaware)	**100%**
Arch Development, LLC (Delaware)	**100%**
Arch Receivable Company, LLC (Delaware)	**100%**
Ashland Terminal, Inc. (Delaware)	**100%**
Canyon Fuel Company, LLC (Delaware)	**35%**
Catenary Coal Holdings, Inc. (Delaware)	**100%**
Cumberland River Coal Company (Delaware)	**100%**
Lone Mountain Processing, Inc. (Delaware)	**100%**
Powell Mountain Energy, LLC (Delaware)	**100%**

Catenary Holdco, Inc. (Delaware)	**100%**
Coal-Mac, Inc. (Kentucky)	**100%**
Energy Development Co. (Iowa)	**100%**
Hobet Holdco, Inc. (Delaware)	**100%**
International Coal Group, Inc. (Delaware)	**100%**
ICG, LLC (Delaware)	**100%**
ICG, Inc. (Delaware)	**100%**
ICG Beckley, LLC (Delaware)	**100%**
ICG Natural Resources, LLC (Delaware)	**100%**
ICG ADDCAR Systems, LLC (Delaware)	**100%**
ICG East Kentucky, LLC (Delaware)	**100%**

ICG Illinois, LLC (Delaware)	100%
ICG Knott County, LLC (Delaware)	100%
ICG Tygart Valley, LLC (Delaware)	100%
Shelby Run Mining Company, LLC (Delaware)	100%
ICG Eastern, LLC (Delaware)	100%
ICG Eastern Land, LLC (Delaware)	100%
ICG Hazard, LLC (Delaware)	100%
ICG Hazard Land, LLC (Delaware)	100%
CoalQuest Development LLC (Delaware)	100%
Hunter Ridge Holdings, Inc. (Delaware)	100%
Hunter Ridge, Inc. (Delaware)	100%
Hunter Ridge Coal Company (Delaware)	100%
White Wolf Energy, Inc. (Virginia)	100%
Bronco Mining Company, Inc. (West Virginia)	100%
Juliana Mining Company, Inc. (West Virginia)	100%
Hawthorne Coal Company, Inc. (West Virginia)	100%
Marine Coal Sales Company (Delaware)	100%
Upshur Property, Inc. (Delaware)	100%
King Knob Coal Co., Inc. (West Virginia)	100%
Vindex Energy Corporation (West Virginia)	100%
Patriot Mining Company, Inc. (West Virginia)	100%
Melrose Coal Company, Inc. (West Virginia)	100%
Wolf Run Mining Company (West Virginia)	100%
The Sycamore Group, LLC (West Virginia)	50%
Simba Group, Inc. (Delaware)	100%
Jacobs Ranch Holdings I LLC (Delaware)	100%
Jacobs Ranch Holdings II LLC (Delaware)	100%
Jacobs Ranch Coal LLC (Delaware)	100%
Mingo Logan Coal Company (Delaware)	100%
Mountain Gem Land, Inc. (West Virginia)	100%
Mountain Mining, Inc. (Delaware)	100%
Mountaineer Land Company (Delaware)	100%
Otter Creek Coal, LLC (Delaware)	100%

P.C. Holding, Inc. (Delaware)	100%
Prairie Holdings, Inc. (Delaware)	100%
Prairie Coal Company, LLC (Delaware)	100%
Saddleback Hills Coal Company (Delaware)	100%

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statements (Form S-3 Nos. 333-157880 and 333-179841) of Arch Coal, Inc. and in the related Prospectus,

(2) Registration Statements (Form S-8 Nos. 333-30565 and 333-112536) pertaining to the Arch Coal, Inc. 1997 Stock Incentive Plan and in the related Prospectus,

(3) Registration Statement (Form S-8 Nos. 333-32777 and 333-156593) pertaining to the Arch Coal, Inc. and Subsidiaries Employee Thrift Plan and in the related Prospectus,

(4) Registration Statements (Form S-8 Nos. 333-68131 and 333-147459) pertaining to the Arch Coal, Inc. Deferred Compensation Plan and in the related Prospectus, and

(5) Registration Statements (Form S-8 Nos. 333-112537 and 333-127548) pertaining to the Arch Coal, Inc. Retirement Account Plan,

of our reports dated March 1, 2013, with respect to the consolidated financial statements and schedule of Arch Coal, Inc. and the effectiveness of internal control over financial reporting of Arch Coal, Inc. included in this Annual Report (Form 10-K) of Arch Coal, Inc. for the year ended December 31, 2012.

/s/ Ernst & Young LLP
St. Louis, Missouri
March 1, 2013

Exhibit 23.2

CONSENT OF WEIR INTERNATIONAL, INC.

We hereby consent to the reference to Weir International, Inc. in the Annual Report on Form 10-K of Arch Coal, Inc. for the year ended December 31, 2012.

We further wish to advise that Weir International, Inc. was not employed on a contingent basis and that at the time of preparation of our report, as well as at present, neither Weir International, Inc. nor any of its employees had, or now has, a substantial interest in Arch Coal, Inc. or any of its affiliates or subsidiaries.

Respectfully submitted,

By: /s/ John W. Sabo

Name: John W. Sabo
Title: Executive Vice President and Managing Director
Date: February, 25, 2013

Exhibit 24.1

Power Of Attorney

KNOW ALL PERSONS BY THESE PRESENTS: That each of the undersigned directors and/or officers of Arch Coal, Inc., a Delaware corporation (“Arch Coal”), hereby constitutes and appoints John W. Eaves, John T. Drexler and Robert G. Jones, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power to act without the other, to sign Arch Coal’s Annual Report on Form 10-K for the year ended December 31, 2012, to be filed with the Securities and Exchange Commission under the provisions of the Securities Exchange Act of 1934, as amended; to file such report and the exhibits thereto and any and all other documents in connection therewith, including without limitation, amendments thereto, with the Securities and Exchange Commission; and to do and perform any and all other acts and things requisite and necessary to be done in connection with the foregoing as fully as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

DATED: March 1, 2013

John W. Eaves	President, Chief Executive Officer
David Freudenthal	Director
Patricia F. Godley	Director
Paul T. Hanrahan	Director
Douglas H. Hunt	Director
J. Thomas Jones	Director
Steven F. Leer	Chairman
George C. Morris, III	Director
A. Michael Perry	Director
Theodore D. Sands	Director
Wesley M. Taylor	Director
Peter I. Wold	Director

Exhibit 31.1

Certification

I, John W. Eaves, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ John W. Eaves
John W. Eaves
President and Chief Executive Officer

Date: March 1, 2013

Exhibit 31.2

Certification

I, John T. Drexler, certify that:

1. I have reviewed this annual report on Form 10-K of Arch Coal, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ John T. Drexler
John T. Drexler
Senior Vice President and Chief Financial Officer

Date: March 1, 2013

Exhibit 32.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
OF ARCH COAL, INC. PURSUANT TO 18. U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, John W. Eaves, President and Chief Executive Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2012 (the "Periodic Report") which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ John W. Eaves
John W. Eaves
President and Chief Executive Officer

Date: March 1, 2013

Exhibit 32.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
OF ARCH COAL, INC. PURSUANT TO 18. U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, John T. Drexler, Senior Vice President and Chief Financial Officer of Arch Coal, Inc., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K for the year ended December 31, 2012 (the "Periodic Report") which this statement accompanies fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) information contained in the Periodic Report fairly presents, in all material respects, the financial condition and results of operations of Arch Coal, Inc.

/s/ John T. Drexler
John T. Drexler
Senior Vice President and Chief Financial Officer

Date: March 1, 2013

EXHIBIT 95

Mine Safety and Health Administration Safety Data

We believe that Arch Coal, Inc. ("Arch Coal") is one of the safest coal mining companies in the world. Safety is a core value at Arch Coal and at our subsidiary operations. We have in place a comprehensive safety program that includes extensive health & safety training for all employees, site inspections, emergency response preparedness, crisis communications training, incident investigation, regulatory compliance training and process auditing, as well as an open dialogue between all levels of employees. The goals of our processes are to eliminate exposure to hazards in the workplace, ensure that we comply with all mine safety regulations, and support regulatory and industry efforts to improve the health and safety of our employees along with the industry as a whole.

The operation of our mines is subject to regulation by the Federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act). MSHA inspects our mines on a regular basis and issues various citations, orders and violations when it believes a violation has occurred under the Mine Act. We present information below regarding certain mining safety and health violations, orders and citations, issued by MSHA and related assessments and legal actions and mine-related fatalities with respect to our coal mining operations. In evaluating the above information regarding mine safety and health, investors should take into account factors such as: (i) the number of citations and orders will vary depending on the size of a coal mine, (ii) the number of citations issued will vary from inspector to inspector and mine to mine, and (iii) citations and orders can be contested and appealed, and in that process are often reduced in severity and amount, and are sometimes dismissed or vacated.

The table below sets forth for the twelve months ended December 31, 2012 for each active MSHA identification number of Arch Coal and its subsidiaries, the total number of: (i) violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard under section 104 of the Mine Act for which the operator received a citation from MSHA; (ii) orders issued under section 104(b) of the Mine Act; (iii) citations and orders for unwarrantable failure of the mine operator to comply with mandatory health or safety standards under section 104(d) of the Mine Act; (iv) flagrant violations under section 110(b)(2) of the Mine Act; (v) imminent danger orders issued under section 107(a) of the Mine Act; (vi) proposed assessments from MHSA (regardless of whether Arch Coal has challenged or appealed the assessment); (vii) mining-related fatalities; (viii) notices from MSHA of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under section 104(e) of the Mine Act; (ix) notices from MSHA regarding the potential to have a pattern of violations as referenced in (viii) above; and (x) pending legal actions before the Federal Mine Safety and Health Review Commission (as of December 31, 2012) involving such coal or other mine, as well as the aggregate number of legal actions instituted and the aggregate number of legal actions resolved during the reporting period.

Mine or Operating Name / MSHA Identification Number	**Section 104 S&S Citations (#)**	**Section 104(b) Orders (#)**	**Section 104(d) Citations and Orders (#)**	**Section 110(b)(2) Violations (#)**	**Section 107(a) Orders (#)**	**Total Dollar Value of MSHA Assessments Proposed (in thousands) ($)**	**Total Number of Mining Related Fatalities (#)**	**Received Notice of Pattern of Violations Under Section 104(e) (yes/no)**	**Received Notice of Potential to Have Pattern of Violations Under Section 104(e) (yes/no)**	**Legal Actions Initiated During Period (#)**	**Legal Actions Resolved During Period (#)**	**Legal Actions Pending as of Last Day of Period(1) (#)**
Active Operations												
Arch Coal Terminal / 15-10358	—	—	—	—	—	0.8	—	No	No	—	—	—
ADDCAR 20 HWM / 12-02416	—	—	—	—	—	—	—	No	No	—	1	—
ADDCAR 11 HWM / 46-08799	—	—	—	—	—	—	—	No	No	—	—	1
ADDCAR 18 HWM / 48-01645	—	—	—	—	—	—	—	No	No	—	—	—
Lone Mountain Darby Fork / 15-02263	13	—	—	—	—	40.3	—	No	No	—	—	—
Lone Mountain Clover Fork / 15-18647	39	—	1	—	—	133.3	—	No	No	—	—	5
Lone Mountain Huff Creek / 15-17234	14	—	—	—	—	43.1	—	No	No	—	—	—
Lone Mountain 6C Mine / 44-06782	3	—	—	—	—	1.9	—	No	No	—	—	—
Lone Mountain Processing / 44-05898	7	—	—	—	1	5.5	—	No	No	—	—	—
Flint Ridge Prep Plant / 15-11991	2	—	—	—	—	0.6	—	No	No	—	—	—
Flint Ridge Mine #2 / 15-18991	39	—	—	—	—	90.1	—	No	No	14	13	24
Hazard South Fork Mine / 15-19391	—	—	—	—	—	—	—	No	No	—	—	—
Hazard Kentucky River Loading / 15-13495	—	—	—	—	—	0.6	—	No	No	—	—	1
Hazard Rowdy Gap Mine / 15-18048	4	—	—	—	—	6.5	—	No	No	2	4	2
Hazard Tip Top Mine / 15-18613	—	—	—	—	—	—	—	No	No	—	—	—
Hazard East Mac & Nellie / 15-18966	16	—	—	—	—	16.3	—	No	No	1	—	1
Hazard Bearville / 15-19416	1	—	—	—	—	2.0	—	No	No	2	2	—

Hazard Thunder Ridge / 15-17746	3	—	—	—	—	2.8	—	No	No	1	1	1
East Kentucky Sandlick Loadout / 15-16290	—	—	—	—	—	0.1	—	No	No	—	—	—
East Kentucky Mt. Sterling Branch / 15-19070	10	—	—	—	—	20.6	—	No	No	3	—	3
East Kentucky Blackberry Creek / 15-	—	—	—	—	—	—	—	No	No	—	—	—

17960												
Powell Mt. Mayflower Plant / 44-05605	1	—	—	—	—	0.7	—	No	No	—	1	—
Powell Mt. Mine #1 / 15-18734	22	—	1	—	—	64.5	—	No	No	5	5	20
Powell Mt. Middle Splint / 44-07207	—	—	—	—	—	—	—	No	No	—	—	1
Knott County Raven #1 / 15-18949	22	—	—	—	—	42.4	—	No	No	10	8	6
Knott County Slone Branch / 15-19323	6	—	—	—	—	8.8	—	No	No	3	—	3
Knott County Raven Prep Plant / 15-17724	5	—	—	—	—	2.4	—	No	No	—	—	—
Knott County Lige Hollow / 15-19497	10	—	—	—	—	18.0	—	No	No	4	5	—
Knott County Kathleen / 15-19447	3	—	—	—	—	6.7	—	No	No	5	1	8
Knott County Supreme Energy Prep Plant / 15-16567	—	—	—	—	—	0.3	—	No	No	—	—	—
Knott County Classic Mine / 15-18522	7	—	—	—	—	21.2	—	No	No	10	8	15
Vindex Cabin Run / 18-00133	2	—	—	—	—	0.4	—	No	No	—	—	—
Vindex Frostburg Blend Yard / 18-00709	—	—	—	—	—	—	—	No	No	—	—	—
Vindex Douglas / 18-00749	2	—	—	—	—	0.7	—	No	No	1	—	1
Vindex Carlos Surface / 18-00769	1	—	—	—	—	0.2	—	No	No	1	1	1
Vindex Bismarck / 46-09369	19	—	1	—	—	14.8	—	No	No	3	3	3
Vindex Dobbin Ridge Prep Plant / 46-07837	5	—	—	—	—	2.9	—	No	No	2	1	2
Vindex Energy / 46-02151	—	—	—	—	—	—	—	No	No	—	2	—
Vindex Jackson Mt. / 18-00170	2	—	—	—	—	0.7	—	No	No	—	—	—
Vindex Wolf Den Run / 18-00790	2	—	—	—	—	0.6	—	No	No	—	—	—
Skyline Mine #3 / 42-01566	22	—	—	—	—	39.4	—	No	No	—	—	1

Sufco / 42-00089	17	1	1	—	—	22.3	—	No	No	1	3	2
Dugout Canyon Mine / 42-01890	16	—	—	—	—	14.8	—	No	No	—	9	1
Dugout Castle Valley Prep Plant / 42-02455	—	—	—	—	—	0.2	—	No	No	—	—	—
Cumberland River Pardee Plant / 44-05014	14	—	—	—	—	6.9	—	No	No	—	—	—
Cumberland River Band Mill Mine / 44-06816	21	—	—	—	—	17.9	—	No	No	—	3	—
Cumberland River Pine Branch #1 / 44-07224	67	—	1	—	—	198.1	—	No	No	2	—	2
Cumberland River Blue Ridge Surface / 15-18769	3	—	—	—	—	4.1	—	No	No	1	2	—
Cumberland River Band Mill #2 / 15-18705	18	1	—	—	—	23.4	—	No	No	2	4	2
Cumberland River Trace Fork #1 / 15-19533	37	1	2	—	1	56.9	—	No	No	3	—	3
Cumberland River Blue Ridge #1 / 15-19228	—	—	—	—	—	—	—	No	No	—	2	1
Beckley Eccles Refuse Area / 46-09023	—	—	—	—	—	—	—	No	No	—	—	—
Beckley Pocahontas Mine / 46-05252	177	3	—	—	—	681.4	1	No	No	13	17	17
Beckley Pocahontas Plant / 46-09216	—	—	—	—	—	0.2	—	No	No	—	1	—
Wolf Run Sawmill Run Prep Plant / 46-05544	5	—	—	—	—	4.1	—	No	No	1	2	1
Wolf Run Imperial Mine / 46-09115	28	—	—	—	—	86.8	—	No	No	9	12	10
Upshur Complex / 46-05823	4	—	—	—	—	13.5	—	No	No	1	—	1
Patriot Mining Company / 46-07654	2	—	—	—	—	0.9	—	No	No	—	—	—
Patriot Rail & River Terminal / 46-07555	—	—	—	—	—	0.1	—	No	No	—	—	—
Eastern Birch River Mine / 46-07945	—	—	—	—	1	0.3	—	No	No	—	—	—
Eastern Bearpen Surface Mine / 46-09220	—	—	—	—	—	—	—	No	No	—	—	—
Eastern Left Fork #1 / 46-09373	—	—	—	—	—	4.0	—	No	No	—	—	—
Eastern Birch River Plant / 46-08390	—	—	—	—	—	0.2	—	No	No	—	—	—
Coal Mac Holden #22 Prep Plant / 46-05909	1	—	—	—	—	0.6	—	No	No	—	—	—
Coal Mac Ragland Loadout / 46-08563	—	—	—	—	—	—	—	No	No	—	—	—

Coal Mac Holden #22 Surface / 46-08984	6	—	—	—	—	12.8	—	No	No	—	—	—
Sentinel Mine / 46-04168	122	—	2	—	—	283.5	—	No	No	14	10	20
Sentinel Prep Plant / 46-08777	6	—	—	—	—	3.4	—	No	No	2	—	3
Mingo Logan Mountaineer II / 46-09029	150	1	4	—	—	119.6	—	No	No	16	8	43
Mingo Logan Cardinal Prep Plant / 46-09046	1	—	—	—	—	0.7	—	No	No	1	—	1
Tygart #1 Mine / 46-09192	16	—	—	—	—	11.9	—	No	No	4	2	2

Arch of Wyoming Seminoe II / 48-00828	—	—	—	—	—	0.2	—	No	No	—	—	—
Arch of Wyoming Elk Mountain / 48-01694	—	—	—	—	—	—	—	No	No	—	—	—
Black Thunder / 48-00977	17	—	4	—	1	29.4	—	No	No	5	1	7
Coal Creek / 48-01215	2	—	—	—	—	1.1	—	No	No	—	—	—
West Elk Mine / 05-03672	46	—	1	—	1	193.7	—	No	No	11	22	18
Viper Mine / 11-02664	83	—	—	—	—	439.4	—	No	No	10	19	14
Lone Mountain Days Creek / 15-17971	—	—	—	—	—	0.1	—	No	No	—	—	—
Leer #1 Prep Plant / 46-09191	—	2	1	—	—	0.1	—	No	No	—	—	—
Inactive Operations												
Flint Ridge Mine #1 / 15-18850	—	—	—	—	—	—	—	No	No	—	2	—
Hazard First Creek / 15-19281	—	—	—	—	—	—	—	No	No	—	2	—
Knott County Calvary / 15-17110	—	—	—	—	—	—	—	No	No	—	1	—
Knott County Clean Energy / 15-18393	—	—	—	—	—	—	—	No	No	—	—	1
Knott County Apollo / 15-19240	—	—	—	—	—	—	—	No	No	—	—	1
Wolf Run Sago / 46-08071	—	—	—	—	—	—	—	No	No	—	—	1
ADDCAR 16 HWM / 12-02356	—	—	—	—	—	—	—	No	No	—	2	—

(1) See table below for additional details regarding Legal Actions Pending as of December 31, 2012.

Mine or Operating Name/MSHA Identification Number	Contests of Citations, Orders (as of December 31, 2012)	Contests of Proposed Penalties (as of December 31, 2012)	Complaints for Compensation (as of December 31, 2012)	Complaints of Discharge, Discrimination or Interference (as of December 31, 2012)	Applications for Temporary Relief (as of December 31, 2012)	Appeals of Judges' Decisions or Orders (as of December 31 2012)
ADDCAR 11 HWM / 46-08799	—	1	—	—	—	—
Lone Mountain Clover Fork / 15-18647	2	3	—	—	—	3
Flint Ridge Mine #2 / 15-18991	—	24	—	—	—	—
Knott County Kathleen / 15-19447	—	8	—	—	—	—
Hazard Kentucky River Loading / 15-13495	—	1	—	—	—	—
Hazard Thunder Ridge / 15-17746	—	1	—	—	—	—
Cumberland River / Trace Fork 15-19533	1	2	—	—	—	—
Hazard East Mac & Nellie / 15-18966	—	1	—	—	—	—
Hazard Rowdy Gap Mine / 15-18048	—	2	—	—	—	—
Powell Mt. Mine #1 / 15-18734	—	20	—	—	—	—
Knott County Raven #1 / 15-18949	—	6	—	—	—	—
Knott County Classic Mine / 15-18522	—	15	—	—	—	—
Knott County Slone's Branch / 15-19323	—	3	—	—	—	—
Knott County Clean Energy / 15-18393	—	1	—	—	—	—
Knott County Apollo / 15-19240	—	1	—	—	—	—
Vindex Bismarck / 46-09369	—	3	—	—	—	—
Vindex Douglas / 18-00749	—	1	—	—	—	—
Skyline Mine #3 / 42-01566	—	1	—	—	—	—
Sufco / 42-00089	—	2	—	—	—	—
Dugout Canyon Mine / 42-01890	—	1	—	—	—	—
Cumberland River Band Mill #2 / 15-18705	—	1	—	2	—	—
Cumberland River Blue Ridge #1 / 15-19228	—	1	—	—	—	—
Beckley Pocahontas Mine / 46-05252	1	15	—	1	—	—
Wolf Run Sawmill Run Prep Plant / 46-05544	—	1	—	—	—	—
Wolf Run Imperial Mine / 46-09115	—	10	—	—	—	—
Sentinel Mine / 46-04168	—	20	—	—	—	1
Sentinel Prep Plant / 46-08777	—	3	—	—	—	—
Wolf Run Sago / 46-08071	—	1	—	—	—	1

Mingo Logan Mountaineer II / 46-09029	2	41	—	—	—	—
Mingo Logan Cardinal Prep Plant / 46-09046	—	1	—	—	—	—
Black Thunder / 48-00977	2	5	—	—	—	—
West Elk Mine / 05-03672	—	18	—	—	—	—
Viper Mine / 11-02664	—	14	—	—	—	—
East Kentucky Mt. Sterling / 15-19070	—	3	—	—	—	—
Vindex Carlos Surface / 18-00769	—	1	—	—	—	—
Vindex Dobbin Ridge Prep / 46-07837	—	2	—	—	—	—
Powell Mountain Middle Splint / 44-07207	—	1	—	—	—	—
Cumberland River Pine Branch #1 / 44-07224	—	2	—	—	—	—
Tygart Valley / 46-09192	—	2	—	—	—	—
Upshur Complex / 46-05823	—	1	—	—	—	—