ARCH COAL INC
Form 10-K
February 28, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

Form 10-K

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

For the fiscal year ended December 31, 2013

or

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

Commission file number: 1-13105

Arch Coal, Inc.

(Exact name of registrant as specified in its charter)

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

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 ý 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 ý 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.

Large accelerated filer ý	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 ý

The aggregate market value of the voting stock held by non-affiliates of the registrant (excluding outstanding shares beneficially owned by directors, officers, other affiliates and treasury shares) as of June 30, 2013 was approximately $791.1 million.

At February 13, 2014 there were 212,279,999 shares of the registrant's common stock outstanding.

Portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission in connection with the 2014 annual stockholders' meeting to be held on April 24, 2014 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, 2013, we sold approximately 140 million tons of coal, including approximately 2.8 million tons of coal we purchased from third parties, representing roughly 14% of the 2013 U.S. coal supply. We sell substantially all of our coal to power plants, steel mills and industrial facilities. At December 31, 2013, we operated, or contracted out the operation of, 22 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 million tons of coal reserves in Central Appalachia to Magnum Coal Company, which was subsequently acquired by Patriot Coal Corporation.

In October 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.

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

In August 2013, we sold the equity interests of Canyon Fuel Company, LLC ("Canyon Fuel"), which owned and operated the Sufco and Skyline longwall mines and the Dugout Canyon continuous miner operation, and controlled approximately 105 million tons of bituminous coal reserves, all located in Utah.

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.

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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 7.8 billion tonnes in 2012 according to The International Energy Agency (IEA) and the World Coal Association. Total hard coal production increased 3% to an estimated 6.9 billion tonnes in 2012 from 2011 levels, while global production of brown coal was relatively flat at 900 million tonnes. Also according to IEA estimates, China remained the largest producer of coal in the world, producing over 3.5 billion tonnes in 2012. The United States and India follow China with hard coal production of over 900 million tonnes and 590 million tonnes, respectively, in 2012.

Cross-border coal trade of hard coal was close to 1.2 billion tonnes in 2013 according to preliminary information. China remained the largest importer of globally traded coal in 2013, taking over 265 million tonnes of hard coal, having surpassed Japan in 2011. Japan imported more than 190 million tonnes in 2013, followed by South Korea with nearly 130 million tonnes, both exhibiting growth. OECD Europe was lower but still relatively strong at over 240 million tonnes.

Among the nations principally supplying coal to the global power and steel markets are Australia and Indonesia, as well as Russia, the United States, Colombia and South Africa. Australia has significant reserves, however 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 governmental attempts to limit exports, may result in a slowing of growth or even a decrease in exports over time. 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 remained challenged in 2013. Europe's weak economic growth resulted in only modest changes in import coal demand. Coal used for power generation fared reasonably well because of the difference in generation costs using coal over natural gas in that area. Additionally, economic uncertainty lowered demand for imported finished goods, which led to reduced steel consumption and therefore lower demand for metallurgical coal. In China, growing demand for electric power increased hard steam coal imports by an estimated 16 million tonnes in 2013. China continues to add coal-based power generation capacity at a rapid pace, but slower economic growth and new regulations on emissions around large urban centers could lead to more moderate growth in the future. Imports of metallurgical coal into China increased over 21 million tonnes in 2013 to a record high 75 million tonnes.

Despite near-term cyclical challenges, coal is expected to remain the dominant fuel for electric power generation. According to the IEA, coal is projected to retain and even modestly improve upon its 41% market share globally. Most of the growth in coal consumption is expected to occur in Asia, with China and India as the largest consumers going forward. In the metallurgical markets, we expect some supply rationalization to occur over the next 12 to 24 months; however, fundamental demand for metallurgical coal appears strong. Again, Asia is expected to be the center for most of the global demand growth for metallurgical coal. China, India, Japan and South Korea are all expected to increase steel production during the next five years.

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

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final data is not yet available, coal consumption in the United States is estimated to be approximately 924 million tons in 2013, according to the Energy Information Administration's (EIA) Short Term Energy Outlook. Coal consumption increased in 2013 following several years of declines on improved competitiveness with other fuels used for power generation, including natural gas.

According to the EIA, coal accounted for approximately 39% of U.S. electricity generation from January through November 2013. This is an increase of approximately 2 percentage points from full-year 2012, as higher natural gas prices allowed coal to recapture some lost market share from 2012. Overall, power generation was generally flat from 2012 to 2013, with the year-to-date total through November down less than 0.2%. Inventories of coal at power generation facilities ended the year close to 146 million tons, according to EIA's Short Term Energy Outlook. This is about 27 million tons or 18% lower than the end of 2012.

The following chart shows the breakdown of U.S. electricity generation by energy source for January through November 2013, according to the EIA:

Source: EIA Electricity Monthly Update (January 2014).

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 2008	Estimated 2013	2014	Forecast 2020	2040	Annual Growth 2012 - 2040
		(Tons, in millions)				
Electric power	1,041	859	887	892	909	0.3%
Other industrial	54	44	45	49	50	0.5%
Coke plants	22	21	23	23	18	(0.5)%
Residential/commercial	4	2	3	2	2	(0.1)%
*Total U.S. coal consumption	1,121	924	955	965	979	0.3%

Source: EIA Annual Energy Outlook 2014
EIA Short Term Energy Outlook (January 2014)
EIA Monthly Energy Review (January 2014)

* 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 of 2011/2012 resulted in record high supplies and inventories

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of natural gas throughout most of 2012. This oversupply altered the competitive balance for much of 2012 and allowed natural gas to gain market share in the power generation market compared to historical levels. The excess inventories of 2012 also affected 2013, but as natural gas demand improved in 2013, prices also moved higher. The higher prices for natural gas allowed coal to recapture some of the lost market share and coal demand has improved, especially in the power generation sector.

The average price of natural gas for the electric power sector in 2013 was $4.44 (EIA, Jan-Oct 2013) which compares to $5.01 and $3.41 in 2011 and 2012, respectively. The 2012 price represented the lowest annual price paid by power generators in over 10 years. Higher natural gas prices in 2013 resulted in increased market share for coal. Through the end of February 2014, natural gas prices have averaged above $4.50 per million Btu or 46% above this time last year. If these trends continue, coal should maintain or improve its competitiveness with natural gas in 2014.

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 and MSHA, U.S. coal production declined an estimated 33 million tons in 2013, to 984 million tons, despite increasing consumption. The decline in production reflects a drawdown of consumer stockpiles and lower coal exports in 2013.

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 543 million tons in 2012 to 533 million tons in 2013 as utilities reduced inventories. 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 divided into north, central and southern regions. According to the EIA, coal produced in the Appalachian region decreased from 294 million tons in 2012 to 285 million tons in 2013, on lower exports and some displacement by coal originating from other regions. Central Appalachia is further disadvantaged for power generation 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 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 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 increased from 180 million tons in 2012 to approximately 183 million tons in 2013. Coal from the Illinois Basin generally has a heat value ranging from 10,100 to 12,600 Btu and has a 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 emissions control devices, such as scrubbers.

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U.S. Coal Exports and Imports. Coal exports declined by approximately 8 million tons to 117 million in 2013, following record exports in 2012. The decline in 2013 was primarily caused by growing global coal supply which displaced some of the volume originating in the United States. Additionally, unfavorable foreign currency exchange and higher shipping rates disadvantaged some United States coal in certain markets. The seaborne market is cyclical, but third-party forecasters project the seaborne coal trade to grow to 1.7 billion tons by 2020, an increase of 350 million tons from 2013 levels. The United States is expected to continue its role as a major supplier to the global market. Interest in access to the coal markets overseas by domestic producers, along with increased international consumer interest in United States coal, continues to fuel considerable interest in developing new port capacity, particularly on the West Coast.

Historically, coal imported from abroad has represented a relatively small share of total domestic coal consumption, and this remained the case in 2013. Imports reached close to 36 million tons in 2007, but have fallen since then. According to the EIA, coal imports declined from 9.2 million tons in 2012 to 8.9 million in 2013. 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 Colombia. Coal imports into the United States have declined every year since 2007, and this trend may continue in 2014.

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.

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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

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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.

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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 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.

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Our Mining Operations

General. At December 31, 2013, we operated, or contracted out the operation of, 22 mines in the United States. Our reportable segments are based on the major coal producing basins in which we operate. Our reportable segments are the Powder River Basin segment, with operations in Wyoming and the Appalachia segment, with operations in West Virginia, Kentucky, Maryland and Virginia; we also sell coal from operations in Colorado and Illinois. Geology, coal transportation routes to consumers, regulatory environments and coal quality can vary from segment to segment. We incorporate by reference the information about the operating results of each of our segments for the years ended December 31, 2013, 2012 and 2011 contained in Note 26, Segment Information, beginning on page F-49.

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, 2013, including the total sales associated with these complexes for the years ended December 31, 2011, 2012 and 2013 and the total reserves associated with these complexes at December 31, 2013. The amount

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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.

Mining Complex	Captive Mines(1)	Contract Mines(1)	Mining Equipment	Railroad	Tons Sold(2)(3) 2011	2012	2013	Total Cost of Property, Plant and Equipment at December 31, 2013	Assigned Reserves (Million tons)
					(Million tons)			($ millions)	
Powder River Basin:									
Black Thunder	S		D, S	UP/BN	104.9	92.9	100.7	$ 1,154.5	1,363.5
Coal Creek	S		D, S	UP/BN	10.0	7.5	8.5	152.1	162.3
Other:									
West Elk	U		LW, CM	UP	5.8	6.7	6.1	471.0	84.2
Viper*	U		CM		1.1	2.1	2.2	85.4	21.5
Appalachia:									
Coal-Mac	S	U	L, E, CM	NS/CSX	3.3	3.3	3.1	209.4	21.8
Cumberland River	U(2)		CM	NS	2.2	1.5	1.0	175.7	19.6
Lone Mountain	U(3)		CM	NS/CSX	2.4	2.0	2.0	247.3	22.8
Mountain Laurel	U	S(2)	L, LW, CM	CSX	4.1	3.7	2.9	520.1	53.0
Hazard*	S(3)		L, S	CSX	1.6	2.1	1.7	5.6	20.9
Beckley*	U		CM	CSX	0.6	1.1	1.1	106.5	31
Vindex*	S		L, S	CSX	0.6	1.0	0.6	85.4	3.9
Sycamore No. 2*		U	CM	CSX	0.2	0.4	0.4	7.0	7.8
Sentinel*	U		CM	CSX	0.6	1.2	1.0	63.6	12.2
Leer*	U		CM, LW	CSX				405.4	33.4
Totals					137.4	125.5	131.3	$ 3,689.0	1,857.9

S = Surface mine	D = Dragline	UP = Union Pacific Railroad
U = Underground mine	L = Loader/truck	CSX = CSX Transportation
	S = Shovel/truck	BN = Burlington Northern-Santa Fe Railway
	E = Excavator/truck	NS = Norfolk Southern Railroad
	LW = Longwall	
	CM = Continuous miner	
	HW = Highwall miner	

*

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 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, 2013. 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) 2012 tons sold numbers do 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. 2013 tons sold numbers do not include tons of coal sold from the following mining complexes that were sold in the 2013 calendar year: Dugout Canyon, Skyline and Sufco. We sold 5.3 million tons of coal from these mining complexes in 2013.

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Powder River Basin

Black Thunder. Black Thunder is a surface mining complex located on approximately 35,800 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 1.4 billion tons of proven and probable reserves at December 31, 2013. 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 2020 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 162.3 million tons of proven and probable reserves at December 31, 2013. 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.

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.

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 21.8 million tons of proven and probable reserves at December 31, 2013. Without the addition of more coal reserves, the current reserves could sustain current production levels until 2019 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 33,300 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 19.6 million tons of proven and probable reserves at December 31, 2013. 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, 2013, the complex consisted of two underground mines operating four continuous miner sections, a preparation plant and a loadout facility. 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 22.8 million tons of proven and probable reserves at December 31, 2013. 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 three underground mines operating a total of seven 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.

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 53.0 million tons of proven and probable reserves at December 31, 2013. 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 five 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 three surface mines, a preparation plant, a unit train loadout and other support facilities located on approximately 119,200 acres in eastern Kentucky. The steam 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. 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.

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A majority of the coal reserves are owned; the remainder are held through private leases. The mining complex had approximately 20.9 million tons of proven and probable reserves at December 31, 2013, which could sustain current production levels until at least 2030.

Beckley. The Beckley mining complex is located on approximately 25,300 acres in Raleigh County, West Virginia. Beckley is extracting metallurgical coal in the Pocahontas No. 3 seam.

A significant portion of the coal reserves are controlled through private leases. As of December 31, 2013, we had approximately 31.0 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 a surface mine located on approximately 40,900 acres in Maryland and West Virginia. Mining operations extract steam and metallurgical 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, 2013, we had approximately 3.9 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 2020.

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 steam 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, 2013, the Sycamore No. 2 mining complex had approximately 7.8 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 steam and metallurgical 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, 2013, we had approximately 12.2 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 33.4 million tons of coal reserves as of December 31, 2013 and has both steam and metallurgical quality coal in the Lower Kittanning seam, and is part of approximately 72,300 acres that is considered our Tygart Valley area. Substantially all of the reserves at Leer are owned rather than leased from third parties.

Construction of the Leer Complex began in June 2010, initial coal production commenced in November 2011 and the longwall began operating in December 2013. 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 high volatile metallurgical and utility markets. 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.

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Other

West Elk. West Elk is an underground mining complex located on approximately 19,500 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 84.2 million tons of proven and probable reserves at December 31, 2013. 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.

Viper. The Viper mining complex consists of one underground coal mine and a preparation plant located on approximately 48,500 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, 2013, we had approximately 21.5 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 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. 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, Beijing 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, 2013, we derived approximately 15% of our total coal revenues from sales to our three largest customers Tennessee Valley Authority, U.S. Steel, and DBK-Donau Brennstoffkontor GmbH and approximately 35% of our total coal revenues from sales to our 10 largest customers.

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In 2013, we sold coal to domestic customers located in 42 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 2013 we also exported coal to Europe, Asia, North America (outside the United States) and South America. Exports to foreign countries were $0.8 billion, $1.2 billion and $0.9 billion for the years ended December 31, 2013, 2012, and 2011, respectively. As of December 31, 2013 and 2012, trade receivables related to metallurgical-quality coal sales totaled $70.5 million and $86.6 million, respectively, or 36% and 35%, 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 shipment destination for the year ended December 31, 2013, were as follows:

(In thousands)		
Europe (includes Morocco)	$	371,363
Asia		160,404
North America		80,322
Central and South America		55,493
Brokered Sales		154,442
Total	$	822,024

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 2013, we sold approximately 59% 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 exceeding five years. At December 31, 2013, the average volume-weighted remaining term of our long-term contracts was approximately 2.84 years, with remaining terms ranging from one to 7 years. At December 31, 2013, remaining tons under long-term supply agreements, including those subject to price re-opener or extension provisions, were approximately 192 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 or changes in economic indices or both. 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

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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, 2013.

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.

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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. 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.

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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 of 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

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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. That rule, however, is subject to a pending challenge in federal court. In addition, on November 30, 2009, OSM announced that it would re-examine and reinterpret the regulations finalized eleven months earlier. Its efforts to reissue the rule are still pending. 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

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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 2013, we recorded $34.6 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, 2013, we have self-bonded an aggregate of approximately $417.6 million, posted an aggregate of approximately $247.3 million in surety bonds for reclamation purposes and secured $18.1 million in letters of credit for reclamation bonding obligations. In addition, we had approximately $49.4 million of surety bonds and letters of credit outstanding at December 31, 2013 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 2013, we recorded $70.1 million of expense related to this excise tax.

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 likely apply to new and existing 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

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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 were 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 2014. 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. The U.S. Supreme Court agreed to hear the EPA's appeal of the decision vacating CSAPR and could reinstate the requirements of CSAPR with a delayed compliance deadline. If so, some coal-fired power plants will be required to install costly pollution controls or shut down. A decision from the U.S. Supreme Court is expected by mid-2014 and may adversely affect the demand for coal.

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, the EPA announced an Electric Generating Unit (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

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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

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determined that it has the authority to regulate greenhouse gas emissions from power plants. In January 2014, EPA proposed performance standards for emissions of carbon dioxide from new fossil-fuel fired power plants. The draft rule proposes a separate standard of performance for coal-fired plants based on partial implementation of carbon capture and storage as the best system of emission reduction. The rule, if finalized and upheld in court, is expected to curtail the construction of new coal-fired power plants. In addition, once a standard for new plants is established, the EPA is required to propose rules imposing performance standards related to carbon dioxide emissions on existing power plants. These rules have not yet been proposed, but if finalized and upheld in court could further curtail the use of coal in power plants.

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

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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 permit holders 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

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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.

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Employees

At December 31, 2013, we employed approximately 5,350 full and part-time employees, approximately 177 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 28, 2014 and their positions and offices during the last five years:

Name	Age	Position
Kenneth D. Cochran	53	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	44	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 2005, Mr. Drexler held several other positions within our finance and accounting department.
John W. Eaves	56	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 a director of Arch Coal, Inc. and 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, and he was previously a director of Advanced Emissions Solutions, Inc.
Robert G. Jones	57	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	53	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. Effective February 2014 Mr. Lang became a director of Arch Coal, Inc. and has been a director of Advanced Emissions Solutions, Inc. since August 2013.

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Name	Age	Position
Deck S. Slone	50	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	51	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.
John A. Ziegler, Jr.	47	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.

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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.

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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;

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- 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 72% of the coal volume we sold in 2013, 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. Sustained periods of 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 2013. 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

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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.

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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, 2013, we derived approximately 15% of our total coal revenues from sales to our three largest customers and approximately 35% 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

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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.

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 China, 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, 2013, we had consolidated indebtedness of approximately $5.2 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

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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."

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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.

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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.

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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.

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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.

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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, 2013, we owned or controlled, primarily through long-term leases, approximately 32,135 acres of coal land in Ohio, 22,417 acres of coal land in Maryland, 46,532 acres of coal land in Virginia, 425,038 acres of coal land in West Virginia, 107,668 acres of coal land in Wyoming, 267,024 acres of coal land in Illinois, 242,773 acres of coal land in Kentucky, 19,428 acres of coal land in Montana, 21,802 acres of coal land in New Mexico, and 20,166 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, Utah and Texas. We lease approximately 88,045 acres of our coal land from the federal government and approximately 24,957 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 leased office 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 5.3 billion tons of proven and probable recoverable reserves at December 31, 2013. Our coal reserve estimates at December 31, 2013 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, 2013:

Total Assigned Reserves
(Tons in millions)

				Sulfur Content (lbs. per million Btus)				Reserve Control		Mining Method		Past Reserve Estimates	
	Total Assigned Recoverable Reserves	Proven	Probable	<1.2	1.2 - 2.5	>2.5	As Received Btus per lb.[1]	Leased	Owned	Surface	Under-ground	2011	2012
Wyoming	1,526	1,497	29	1,448	78		8,869	1,526		1,526		1,474	1,636
Montana													
Utah												79	74
Colorado	84	69	15	84			11,335	84			84	88	80
Central App.	169	155	14	49	120		12,920	163	6	78	91	308	213
Northern App.	58	47	11		41	17	12,928	23	35	4	54	238	231
Illinois	21	13	8			21	10,797	19	2		21	30	18
Total	1,858	1,781	77	1,581	239	38	9,497	1,815	43	1,608	250	2,217	2,252

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

Total Unassigned Reserves
(Tons in millions)

				Sulfur Content (lbs. per million Btus)				Reserve Control		Mining Method	
	Total Unassigned Recoverable Reserves	Proven	Probable	<1.2	1.2 - 2.5	>2.5	As Received Btus per lb.[1]	Leased	Owned	Surface	Under-ground
Wyoming	480	397	83	428	52		9,653	370	110	305	175
Montana	1,387	1,129	258	1,387			8,603	1,387		1,387	
Utah											
Colorado	26	18	8	26			11,024	26			26
Central App.	446	297	149	128	226	92	12,966	367	79	93	353
Northern App.	385	199	186	3	273	109	12,914	62	323	11	374
Illinois	696	345	351	1	51	644	10,971	82	614	2	694
Total	3,420	2,385	1,035	1,973	602	845	10,305	2,294	1,126	1,798	1,622

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

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 67% consist of compliance coal, or coal which emits 1.2 pounds or less of sulfur dioxide per million Btus upon combustion, while an additional approximately 6% 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, 2013 was $4.9 billion, consisting of $95.7 million of prepaid royalties and a net book value of coal lands and mineral rights of $4.8 billion.

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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

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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, 2013, approximately 22% 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 38,184 acres of property to other coal operators in 2013. We received royalty income of $9.5 million in 2013 from the mining of approximately 2.8 million tons, $10.0 million in 2012 from the mining of approximately 3.1 million tons and $8.2 million in 2011 from the mining of approximately 2.9 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

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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 (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" then pending in federal court in Washington, DC. In a Memorandum and Opinion and separate Order, each dated March 23, 2012, the federal court 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. As described more fully below, EPA appealed that order to the United States Court of Appeals for the DC circuit and by Opinion of the Court dated April 23, 2013, the court reversed the lower court's order and remanded the matter to the district court for further proceedings.

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 and the matter remains 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 court heard oral arguments on March 14, 2013. By opinion of the court filed on April 23, 2013, the court reversed the district court on the threshold issue and remanded the matter to the district court to address the merits of our APA challenge to the Final Determination. On June 6, 2013, Mingo Logan filed a Petition for Rehearing En Banc and by Order filed July 25, 2013, the court denied the petition.

On November 13, 2013, Mingo Logan filed a Petition for Writ of Certiorari with the Supreme Court of the United States seeking review of the DC Circuit's decision. The EPA has filed their response and Mingo Logan's reply is due on March 4, 2014 after which the Petition will be pending for consideration.

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, which consisted of $13.8 million for past damages, and $90.3 million for future damages. 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 affirmed the award of past damages, but ruled that the lower court should have calculated future damages as of the date of breach, and remanded the matter back to the lower court with instructions to recalculate that portion of 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. On July 2, 2013, the Supreme Court of Pennsylvania denied the Petition of Allowance. As this action finalized the past damage award, Wolf Run paid $15.6 million for the past damage amount, including interest, to Allegheny in July 2013. The future damage award is now back before the lower court, and a new trial has been scheduled to start May 13, 2014.

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. The court heard oral arguments from the parties on October 8, 2013 and the matter is pending a decision by the court.

Patriot Coal Corporation Bankruptcy

On December 31, 2005, we 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 accrued $58.3 million, representing the discounted value of the remaining monthly buyout amounts under the underlying coal sales agreement.

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On October 4, 2013, we entered into a term sheet that set forth the principle terms of a settlement with Patriot, and the U.S. Bankruptcy Court entered an order approving the settlement terms on November 7, 2013, resolving all pending and potential legal claims arising out of the December 31, 2005 sale of assets to Magnum. We agreed to pay $5.0 million to Patriot upon its exit from bankruptcy as part of the settlement agreement. Additionally, the settlement includes the release of a $16.7 million letter of credit posted by Patriot in the Company's favor for surety bonds related to the companies sold to Magnum. The Company also purchased Patriot's Guffey reserves (which are included in the unassigned reserves totals as of December 31, 2013) for $16.0 million in cash upon their exit from bankruptcy.

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, 2013.

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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 13, 2014, our common stock closed at $3.95 on the New York Stock Exchange. On that date, there were approximately 5,900 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 have historically been paid in mid-March, June, September and December. In 2014 we have announced a payment of an annual dividend in March. We paid dividends on our common stock totaling $25.5 million, or $0.12 per share, in 2013, and $42.4 million, or $0.20 per share, in 2012. 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 13, Debt and Financing Arrangements, beginning on Page F-27 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.

	2013			
	March 31	June 30	September 30	December 31
Dividends per common share	$ 0.03	$ 0.03	$ 0.03	$ 0.03
High	7.95	5.82	5.25	4.77
Low	4.89	3.47	3.6	3.75

	2012			
	March 31	June 30	September 30	December 31
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

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, 2008;
- all dividends were reinvested;
- annual reweighting of the peer groups; and
- you continued to hold your investment through December 31, 2013.

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

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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 12/31/08 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

	12/08	12/09	12/10	12/11	12/12	12/13
Arch Coal, Inc.	100.00	139.45	223.42	94.30	48.62	30.31
S&P Midcap 400	100.00	137.38	173.98	170.96	201.53	269.04
Industry Peer Group	100.00	196.45	248.94	139.00	107.54	101.49

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, 2013. As of December 31, 2013, 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 13, 2014, there is approximately $43.2 million of our common stock that may yet be purchased under this program.

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ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31				
(In thousands, except per share data)	2013(1)	2012(2)	2011(3)	2010(4)(5)	2009(6)
Statement of Operations Data:					
Revenues	$ 3,014,357	$ 3,768,126	$ 3,883,039	$ 2,817,441	$ 2,177,424
Mine closure and asset impairment costs	220,879	539,182	7,316		
Goodwill impairment	265,423	330,680			
Acquisition and transition costs			47,360		
Income (loss) from operations	(663,141)	(757,012)	343,061	291,782	78,291
Non-operating expenses	(42,921)	(23,668)	(51,448)	(6,776)	
Income (loss) from continuing operations	(745,228)	(738,915)	89,015	131,364	5,025
Diluted earnings (loss) from continuing operations per common share	$ (3.52)	$ (3.50)	$ 0.47	$ 0.62	$ 0.03
Net income (loss) attributable to Arch Coal	$ (641,832)	$ (683,955)	$ 141,683	$ 158,857	$ 42,169
Basic earnings (loss) per common share	$ (3.03)	$ (3.24)	$ 0.75	$ 0.98	$ 0.28
Diluted earnings (loss) per common share	$ (3.03)	$ (3.24)	$ 0.74	$ 0.97	$ 0.28
Balance Sheet Data:					
Total assets	$ 8,990,193	$ 10,006,777	$ 10,213,959	$ 4,880,769	$ 4,840,596
Working capital	1,293,849	1,337,035	162,106	207,568	55,055
Long-term debt, less current maturities	5,118,002	5,085,879	3,762,297	1,538,744	1,540,223
Other long-term obligations	717,174	825,080	864,667	566,728	544,578
Noncurrent deferred income tax liability	413,546	664,182	976,753		
Arch Coal stockholders' equity	2,253,249	2,854,567	3,578,040	2,237,507	2,115,106
Common Stock Data:					
Dividends per share	$ 0.12	$ 0.20	$ 0.43	$ 0.39	$ 0.36
Shares outstanding at year-end	212,280	212,247	211,671	162,605	162,441
Cash Flow Data:					
Cash provided by operating activities	55,742	332,804	642,242	697,147	382,980
Depreciation, depletion and amortization, including amortization of acquired sales contracts, net	438,247	500,319	444,518	400,672	321,231
Capital expenditures	296,984	395,225	540,936	314,657	323,150
Acquisitions of businesses, net of cash acquired			2,894,339		768,819
Net proceeds from the issuance of long term debt	618,525	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	629,172	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)
Dividend payments	25,475	42,440	80,748	63,373	54,969
Operating Data:					
Tons sold	139,607	140,820	156,897	162,763	126,116
Tons produced	136,613	135,934	151,829	156,282	119,568
Tons purchased from third parties	2,925	4,327	5,557	6,825	7,477

(1) As part of a strategy to divest non-core thermal coal assets, on August 16, 2013, we sold Canyon Fuel Company, LLC ("Canyon Fuel") to Bowie Resources, LLC for $423 million. Canyon Fuel operated the Sufco and Skyline longwall mining complexes and the Dugout Canyon continuous miner operation in Utah. We recognized a gain on the sale of Canyon Fuel, net of tax, of $77.0 million during the third quarter of 2013. See Note 3 to the consolidated financial statements, "Discontinued Operations," for further information.

(2)

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. We also recognized goodwill impairment charges due to the weak markets totaling $330.7 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.

(3)

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.

(4)

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.

(5)

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.

(6)

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.

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

Overview

The weakness in global coal markets continued throughout 2013, impacting our results primarily due to lower metallurgical coal pricing and lower metallurgical coal sales volumes in our Appalachian segment. Both metallurgical coal and international thermal coal markets remain oversupplied, which will continue to impact our operations in 2014. We exported 11.4 million tons in 2013, compared to approximately 13.6 million tons in 2012. We expect our export shipments to decline in 2014. We expect that international demand for metallurgical and thermal coal will continue to grow in 2014. As global coal growth projects cease and reserves deplete, we expect that excess supply will be absorbed by growing international demand for coal, ultimately leading to more balanced markets over time.

At the same time, trends relating to the domestic thermal coal markets are improving. According to internal estimates, U.S. coal consumption for power generation rose by more than 35 million tons in 2013, while U.S. coal production of 984 million tons reached its lowest level since the early 1990's. As a result, U.S. power generator coal stockpiles built during 2012 fell meaningfully over the course of the year. The cold weather across much of the country in the winter of 2013/2014 should contribute further to the liquidation of these stockpiles. In addition, natural gas prices have increased compared with prior year, which we believe ensures that most domestic coal is competitively priced for power generation. Thermal coal market recovery has not been even amongst the coal basins, primarily due to a higher-cost Appalachian coal basin. We recorded fixed asset impairment charges related to certain mining and other operations in the Appalachia region of approximately $126.4 million and goodwill impairment charges of $265.4 million during 2013. See "Results of operations" for further discussion.

Management has continued to focus on capital spending reductions, cost containment and efficiency efforts and working capital and liquidity management to improve cash flows and prepare the company to capitalize on opportunities when coal markets recover.

As part of a strategy to divest non-core thermal coal assets, on August 16, 2013, we sold Canyon Fuel Company, LLC ("Canyon Fuel") to Bowie Resources, LLC for $422.7 million. Canyon Fuel operated the Sufco and Skyline longwall mining complexes and the Dugout Canyon continuous miner operation in Utah. We recognized a gain on the sale of Canyon Fuel, net of tax, of $77.0 million. See Note 3 to the consolidated financial statements, "Discontinued Operations," for further information.

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Operational Performance

The following table shows operating results of continuing coal operations for the years ended December 31, 2013, 2012, and 2011. The "other" category includes the results of our other bituminous thermal operations, our West Elk mining complex in Colorado and our Viper mining complex in Illinois.

	Year Ended December 31,		
	2013	2012	2011
Powder River Basin			
Tons sold (in thousands)	111,654	104,394	117,846
Coal sales realization per ton sold(1)	$ 12.44	$ 13.61	$ 13.62
Cost per ton sold	$ 12.16	$ 12.77	$ 12.11
Operating margin per ton sold(2)	$ 0.28	$ 0.84	$ 1.51
Adjusted EBITDA(3) (in thousands)	$ 209,211	$ 265,231	$ 370,423
Appalachia			
Tons sold (in thousands)	14,224	18,717	20,874
Coal sales realization per ton sold(1)	$ 73.07	$ 85.42	$ 84.52
Cost per ton sold	$ 80.54	$ 83.17	$ 70.88
Operating margin (loss) per ton sold(2)	$ (7.47)	$ 2.25	$ 13.64
Adjusted EBITDA(3) (in thousands)	$ 84,201	$ 395,806	$ 468,806
Other			
Tons sold (in thousands)	8,422	8,820	6,952
Coal sales realization per ton sold(1)	$ 32.63	$ 34.39	$ 36.11
Cost per ton sold	$ 27.49	$ 26.99	$ 28.98
Operating margin per ton sold(2)	$ 5.14	$ 7.40	$ 7.13
Adjusted EBITDA(3) (in thousands)	$ 97,489	$ 121,396	$ 89,844

(1) These per-ton measurements reflect classification adjustments to numbers reported under U.S. GAAP to reflect 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.

(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 or loss attributable to the segment 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.

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Segment Adjusted EBITDA is reconciled to net income (loss) at the end of this "Results of Operations" section.

Reconciliation to amounts reported in statement of operations	**Year Ended December 31, 2013**	**2012**	**2011**
Transportation costs netted against per-ton realizations to reflect netback price to the region			
Powder River Basin	$ 0.84	$ 1.00	$ 0.36
Appalachia	$ 8.22	$ 11.18	$ 7.22
Other	$ 14.13	$ 17.00	$ 9.30
API-2 risk management position settlements included in per-ton realizations not classified as coal sales revenues in statement of operations			
Appalachia	$ 0.74	$ 0.78	$
Other	$ 2.61	$ 2.64	$
Diesel risk management position settlements not classified as cost of coal sales in statement of operations			
Powder River Basin	$ 0.10	$ 0.09	$
Appalachia	$ 0.25	$ 0.10	$

Powder River Basin Segment Adjusted EBITDA decreased in 2013 when compared to 2012 due to continued weak coal market conditions, which resulted in lower per-ton realizations. The increase in coal consumption by electric generation facilities contributed to an increase of 7% in sales volumes. Per-ton costs decreased 5% in 2013 when compared with 2012 as a result of cost control efforts and the increase in sales volumes, as well as a decrease in production taxes and royalties that fluctuate with selling prices ($0.24 per ton).

Segment Adjusted EBITDA decreased in 2012 when compared to 2011, due to the lower sales volumes from the production curtailments in response to market conditions, and the resulting higher per-ton cash costs.

Appalachia Segment Adjusted EBITDA decreased significantly in 2013 when compared to 2012 due to the weaker coal market conditions, which resulted in lower coal sales volumes and also lower average coal pricing. The decrease in pricing was particularly pronounced on metallurgical coal shipments. We sold 6.8 million tons of metallurgical-quality coal in 2013 compared to 7.5 million tons in 2012. Part of the volume differential in Appalachia was due to geologic issues at the Mountain Laurel mine, which we expect to continue through the first quarter of 2014. Per-ton costs have decreased, despite the significant decrease in sales volumes, as we closed higher-cost coal operations in 2012 in response to the challenging market conditions, which contributed approximately $5 to cost per ton in 2012. In addition, our cost containment and efficiency efforts contributed to lower costs in 2013, as did a decrease in production taxes and royalties that fluctuate with selling prices, which decreased $1.07 per ton in 2013 when compared with 2012.

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 the current 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 from the $79.5 million decrease in a legal contingent liability acquired with ICG.

Other EBITDA and margins were higher in 2012 as a result of lower production costs stemming from improved cost control, higher sales volumes from lower costs mines and and reductions to accruals for sales-sensitive costs. In 2013, margins and EBITDA were impacted by lower price realizations due to the weak thermal coal markets.

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Results of Operations

The following tables reflect the amounts as presented in our consolidated statements of operations. Individual line items exclude the results of Canyon Fuel, including the gain on the sale, as those amounts are presented as one line item, "Income from discontinued operations, including gain on sale net of tax", in the consolidated statements of operations.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Summary. Our results during the year ended December 31, 2013, when compared to the year ended December 31, 2012, were impacted by weak market conditions and related impairment charges in both 2013 and 2012, in part offset by the gain on the sale of Canyon Fuel in 2013.

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

Coal sales. The following table compares information about coal sales during the year ended December 31, 2013 with the information for the year ended December 31, 2012:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Increase (Decrease)
		(In thousands)	
Coal sales	$ 3,000,476	$ 3,747,971	$ (747,495)
Tons sold	134,300	131,931	2,369

Coal sales decreased approximately 20% in 2013 compared with 2012 due to lower realized prices. Lower average realizations per ton sold, the result of the weak coal markets, including a decrease in export sales, and a lower percentage of higher-priced coal sales out of Appalachia, resulted in a decrease in coal sales revenues of approximately $456 million. The increase in sales volumes in our Powder River Basin segment ($99 million) was offset by the impact of lower volumes from Appalachia and other segments ($390 million).

Costs, expenses and other. The following table compares costs, expenses and other components of operating income for the year ended December 31, 2013 with the information for the year ended December 31, 2012:

	Year Ended December 31, 2013	Year Ended December 31, 2012	(Increase) Decrease in Net Loss
		(Amounts in thousands)	
Cost of sales (exclusive of items shown separately below)	$ 2,663,136	$ 3,155,099	$ 491,963
Depreciation, depletion and amortization	426,442	492,211	65,769
Amortization of acquired sales contracts, net	(9,457)	(25,189)	(15,732)
Change in fair value of coal derivatives and coal trading activities, net	7,845	(16,590)	(24,435)
Coal derivative settlements, non-hedging	(32,534)	(43,990)	(11,456)
Asset impairment and mine closure costs	220,879	539,182	318,303
Goodwill impairment	265,423	330,680	65,257
Contract settlement resulting from Patriot Coal bankruptcy		58,335	58,335
Reduction in accrual related to acquired litigation		(79,532)	(79,532)
Selling, general and administrative expenses	133,448	134,299	851
Other operating expense (income), net	2,316	(19,367)	(21,683)
Total costs, expenses and other	$ 3,677,498	$ 4,525,138	$ 847,640

Cost of sales. Our cost of sales decreased in 2013 from 2012 primarily due to lower average per-ton production costs ($409 million) , the result of a change in regional mix that reflects lower sales volumes from the Appalachia segment. In addition, transportation costs decreased $133 million in 2013 from 2012 due to a decrease

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in export shipments. The increase in sales volumes resulted in an increase of $42 million in cost of sales. These factors are discussed in detail in the "Operational performance" section.

Depreciation, depletion and amortization. When compared with 2012, depreciation, depletion and amortization costs decreased in 2013 due to asset impairments and the decreases in production in the Appalachia and other segments for the respective periods, including the impact of mine closures in 2012.

Change in fair value of coal derivatives and coal trading activities, net. The gains reflected in 2012 relate primarily to positions taken in 2012 in the API-2 market, the derivatives market for coal delivered into Europe. We entered into these positions taken in 2012 to manage price risk on physical export sales into Europe. As these positions are not accounted for as hedges, changes in the positions' fair value prior to settlement are recognized in this line on the consolidated statement of operations. When the positions settle, the realized gains and losses are reclassified to "Coal derivative settlements, non-hedging". The decrease from gains in 2012 to losses in 2013 is the result of a decrease in positions outstanding, due to settlements during the year.

Coal derivative settlements, non-hedging. These gains reflect the realized settlement income reclassified from the line "Change in fair value of coal derivatives and coal trading activities, net", and consist primarily of the realized gains on API-2 positions.

Asset impairment and mine closure costs. In response to market conditions, we recorded impairment charges in 2013 related to a Kentucky coal operation and our highwall mining equipment subsidiary. In addition, we recorded other-than-temporary impairment charges related to equity method investees. In 2012, we closed or idled five mining operations in response to market conditions. See further discussion in Note 5 ,"Impairment Charges and Mine Closure Costs", and Note 9, "Equity Method Investments and Membership Interests in Joint Ventures", to the consolidated financial statements.

Goodwill impairment. In 2012, we recognized an impairment charge of $115.8 million, the entire balance of goodwill allocated to our Black Thunder mining complex, due to expectations of lower thermal coal demand and its impact on near-term sales volumes and pricing, and $214.9 million related to two of four operating units that were allocated goodwill in the acquisition of ICG, due to a drop in near-term metallurgical coal prices. The remaining $265.4 million of goodwill from the ICG acquisition was impaired in the fourth quarter of 2013, as a result of continuing weakness in the metallurgical coal markets. See further discussion in "Critical Accounting Policies".

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.

Reduction in accrual related to acquired litigation. As a result of a 2012 legal ruling in a lawsuit against former ICG subsidiaries, we changed our assessment of the probable loss related to the lawsuit. The suit is discussed in detail in Note 25 to the consolidated financial statements.

Selling, general and administrative expenses. Selling, general and administrative expenses in 2013 decreased slightly when compared with 2012, due to lower discretionary spending levels in 2013, which were partially offset by the impact of lower bonus and incentive plan costs in 2012 as certain performance targets were not achieved in 2012. Cost reductions in 2013 were achieved primarily through a decrease in industry group dues and fees of $6.4 million, and decreases in legal and other professional fees.

Other operating expense (income), net. When compared with 2012, liquidated damages on throughput commitments increased $9.4 million in 2013, commercial-related income decreased by $17.9 million, and gains on asset sales decreased from $11.8 million in 2012 to $4.6 million in 2013. These items were partially offset by a decrease in 2013 in unrealized losses relating to our diesel purchase and fuel surcharge risk management programs of $11.3 million.

Net interest expense. The following table summarizes our net interest expense for the year ended December 31, 2013 and compares it with the information for the year ended December 31, 2012:

	Year Ended December 31,		(Increase) Decrease
	2013	2012	in Net Loss
	(In thousands)		
Interest expense	$ (381,267)	$ (317,615)	$ (63,652)
Interest and investment income	6,603	5,473	1,130
	$ (374,664)	$ (312,142)	$ (62,522)

The increase in interest expense is due to an increase in our outstanding debt in 2013 when compared with 2012, primarily as a result of financing transactions completed during 2012, which resulted in a net increase in debt outstanding of over $1 billion.

Non-operating expense. The following table summarizes non-operating expense for the year ended December 31, 2013 and compares it with the information for the year ended December 31, 2012:

	Year Ended December 31,		Increase
	2013	2012	$
	(Amounts in thousands)		
Net loss resulting from early retirement and refinancing of debt	$ (42,921)	$ (23,668)	$ (19,253)

Amounts reported as nonoperating consist of expenses resulting from financing activities, other than interest costs. In the fourth quarter of 2013, we retired our 8.75% senior notes due in 2016 and reduced the capacity of our revolving credit facility, in conjunction with a refinancing discussed in the "Liquidity" section. As a result, we paid a tender premium and wrote off unamortized discount and fees. During 2012, nonoperating expense consists primarily of the write-off of financing fees relating to decreases in our revolving credit facility capacity.

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion.

	Year Ended December 31,		
	2013	2012	Decrease
	(In thousands)		
Benefit from income taxes	(335,498)	(353,907)	(18,409)

In 2013 and 2012, our benefit was impacted by $70.3 million and $56.9 million, respectively, of non-deductible goodwill adjustments and $8.7 million and $31.8 million, respectively, to increase our valuation allowance against state and foreign tax carryforwards.

Income from discontinued operations, net of tax. Canyon Fuel's results and the $77.0 million gain from its sale in 2013, net of the related income tax impacts, are segregated from continuing operations.

	Year Ended December 31,		
	2013	2012	Increase
	(In thousands)		
Income from discontinued operations, net of tax	103,396	55,228	48,168

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See Note 3 "Discontinued Operations", to the consolidated financial statements for further information.

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,		
	2012	**2011**	**Increase (Decrease)**
	(Amounts in thousands)		
Coal sales	$ 3,747,971	3,877,749	(129,778)
Tons sold	131,931	145,672	(13,741)

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 (a decrease in coal sales of $342 million) was partially offset by higher coal sales realizations per ton (an increase of $212 million), as increased export activity resulted in higher selling prices. 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 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**	**in Net Income**
	(Amounts in thousands)		
Cost of sales (exclusive of items shown separately below)	$ 3,155,099	$ 2,980,354	$ (174,745)
Depreciation, depletion and amortization	492,211	420,980	(71,231)
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
Asset impairment and mine closure costs	539,182	7,316	(531,866)
Goodwill impairment	330,680		(330,680)
Contract settlement resulting from Patriot Coal bankruptcy	58,335		(58,335)
Reduction in accrual related to acquired litigation	(79,532)		79,532
Acquisition and transition costs		47,360	47,360
Selling, general and administrative expenses	134,299	119,056	(15,243)
Other operating income, net	(19,367)	(10,119)	9,248
Total costs, expenses and other	$ 4,525,138	$ 3,539,978	$ (985,160)

Cost of coal sales. Our cost of sales increased in 2012 from 2011 primarily from the impact of the acquisition of the ICG operations ($237.8 million) and an increase in transportation costs as a result of the increase in export shipments ($206.0 million). 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 ($269.0 million).

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

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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. See the explanation in the comparison of 2013 to 2012 results.

Coal derivative settlements, non-hedging. See the explanation in the comparison of 2013 to 2012 results.

Asset impairment and mine closure costs. In 2012, we closed or idled five of our mining operations, in addition to curtailing production at other locations, in response to market conditions. As a result, we recognized impairment charges to write down property, plant, and equipment, and incurred other costs, primary labor and contract termination, related to the closures. See further detail in Note 5 to the consolidated financial statements, "Impairment Charges and Mine Closure Costs."

Goodwill impairment. See the explanation in the comparison of 2013 to 2012 results.

Contract settlement resulting from Patriot Coal bankruptcy. See the explanation in the comparison of 2013 to 2012 results.

Reduction in accrual related to acquired litigation. See the explanation in the comparison of 2013 to 2012 results.

Acquisition and transition costs. These costs relate to the acquisition of ICG.

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.

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)		
Interest expense	$ (317,615)	$ (230,186)	$ (87,429)
Interest income	5,473	3,309	2,164
	$ (312,142)	$ (226,877)	$ (85,265)

The increase in interest expense is due to an increase in our outstanding debt in 2012 when compared with 2011, primarily as a result of financing transactions completed during 2012, which resulted in a net increase in debt outstanding of over $1 billion.

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Non-operating expense. The following table summarizes non-operating 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, 2012	Year Ended December 31, 2011	Increase (Decrease) in Net Income $
	(Amounts in thousands)		
Net loss resulting from early retirement and refinancing of debt	$ (23,668)	$ (1,958)	$ (21,710)
Acquisition bridge financing costs		(49,490)	49,490
	$ (23,668)	$ (51,448)	$ 27,780

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.

Income taxes. Our effective income tax rate is sensitive to changes in and the relationship between annual profitability and the deduction for percentage depletion.

	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase
	(In thousands)		
Benefit from income taxes	(353,907)	(24,279)	329,628

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.

Income from discontinued operations, net of tax. Canyon Fuel's results and the gain from its sale, net of the related income tax impacts, are segregated from continuing operations. See Note 3 to the consolidated financial statements, "Discontinued Operations" for further information.

	Year Ended December 31, 2012	Year Ended December 31, 2011	Increase
	(In thousands)		
Income from discontinued operations, net of tax	55,228	53,825	1,403

Reconciliation of Segment Adjusted EBITDA to Net Income

The discussion in "Results of Operations" includes references to our Adjusted EBITDA. 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

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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,		
	2013	2012	2011
Reported Segment Adjusted EBITDA	$ 390,901	$ 782,433	$ 929,073
EBITDA from discontinued operations	173,776	108,850	116,122
Corporate and other[(1)]	(138,755)	(202,829)	(124,057)
Adjusted EBITDA	425,922	688,454	921,138
Income tax benefit	335,498	353,907	24,279
Interest expense, net	(374,664)	(312,142)	(226,877)
Depreciation, depletion and amortization	(426,442)	(492,211)	(420,980)
Amortization of acquired sales contracts, net	9,457	25,189	22,069
Asset impairment and mine closure costs	(220,879)	(539,182)	(7,316)
Goodwill impairment	(265,423)	(330,680)	
Settlement of UMWA legal claims	(12,000)		
Acquisition and transition costs			(56,885)
Other nonoperating expenses	(42,921)	(23,668)	(51,448)
Interest, taxes, and depreciation, depletion and amortization classified as discontinued operations	(70,380)	(53,622)	(62,297)
Net income (loss) attributable to Arch Coal	$ (641,832)	$ (683,955)	$ 141,683

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

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 or refinancing activity. 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, cash on hand or borrowings under our lines of credit. Such plans are subject to change based on our cash needs.

As described below, we took actions during the fourth quarter of 2013 to further bolster our liquidity and extend debt maturities. These proactive steps will help us navigate the current market cycle by providing us greater flexibility. We now have more than $1.4 billion of liquidity, with $1.2 billion of that in cash or highly liquid investments. We have no meaningful maturities of debt until 2018, after successfully refinancing our 2016 notes without increasing our interest costs; and significantly relaxed financial maintenance covenants. We have suspended or eliminated most financial maintenance covenants that pertain to our $250 million revolver until June of 2015, when a relaxed, senior secured leverage ratio covenant steps back in. Until then, only a minimum liquidity covenant remains in place. With these transactions, we have implemented a flexible capital structure, with a high levels of pre-payable debt, which should allow us to de-lever our balance sheet, should markets and our cash flows improve.

We will maintain our focus on capital spending and cost reductions, operating efficiencies, and divestiture of non-core assets until coal markets improve to help preserve our liquidity.

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Financing activities

On December 17, 2013, we entered into an amendment of the credit agreement governing our term loan and revolving credit facility whereby our term loan facility was increased to accommodate an incremental $300.0 million aggregate principal loan at 98% of the face amount and commitments under the revolving credit facility were reduced to $250.0 million from $350.0 million. Also on December 17, 2013, we issued $350.0 million aggregate principal amount of 8.00% senior secured second lien notes due 2019 (the "2019 Secured Notes") at par. The 2019 Secured Notes are secured by the same assets that secure indebtedness under the senior secured credit facility, but on a second priority basis, subject to certain exceptions and permitted liens. With the proceeds from these transactions, we retired the remaining $600 million in aggregate principal amount of 8.75% senior unsecured notes due 2016 ("2016 Notes") for $628.7 million.

Long-Term Debt

Our indebtedness consisted of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Term loan due 2018 ($1.93 billion and $1.65 billion face value, respectively)	$ 1,906,975	$ 1,627,384
8.75% senior notes ($600.0 million face value) due 2016		590,999
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	362,358	360,042
8.00% senior secured notes due 2019 at par	350,000	
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	32,162	40,350
	5,151,495	5,118,775
Less current maturities of debt	33,493	32,896
Long-term debt	$ 5,118,002	$ 5,085,879

There were no borrowings under lines of credit during the year ended December 31, 2013. Our average borrowing level under lines of credit was approximately $200.0 million for the year ended December 31, 2012.

The following is a summary of cash provided by or used in each of the indicated types of activities during the year ended December 31, 2013, 2012, and 2011:

	Year Ended December 31, 2013	2012	2011
	(In thousands)		
Cash provided by (used in):			
Operating activities	$ 55,742	$ 332,804	$ 642,242
Investing activities	125,445	(649,166)	(3,496,916)
Financing activities	(54,710)	962,835	2,899,230

Cash provided by operating activities decreased in 2013 compared to 2012, and in 2012 compared to 2011, driven by the impacts on our operating profitability of weak coal market conditions.

We generated cash from investing activities of $125.4 million in 2013, including $422.7 million from the sale of Canyon Fuel, compared to cash used in investing activities of $649.2 million in 2012. In order to preserve

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liquidity, we reduced capital expenditures by $98 million in 2013 when compared with 2012. We focused our spending on expanding our metallurgical coal production capacity, and in 2013, 2012 and 2011 we spent approximately $109 million, net of proceeds from the sale and leaseback of longwall shields, $195 million and $73 million on the development of the Leer mining complex. With the Leer mining complex reaching its production stage in January 2014, we expect capital expenditures to be lower in 2014. With the proceeds from our 2012 financing activities discussed below, we purchased short term investments, and gross purchases totaled $213.7 million and $236.9 million in 2013 and 2012, respectively, and we received proceeds from the sales of short term investments of $194.5 million in 2013. In 2012, we purchased the noncontrolling interest in Arch Western for $17.5 million. Cash used in investing activities in 2011 reflects the ICG acquisition ($2.9 billion) and also higher royalty payments and investments in equity method subsidiaries.

Cash used in financing activities was approximately $54.7 million in 2013, compared to cash provided by financing activities of approximately $962.8 million in 2012 and $2.9 billion in 2011. In 2012, the proceeds from the $1.4 billion term loan in conjunction with the refinancing of our revolving credit facility were used, in part, to retire the remaining outstanding senior secured notes due in 2013 and the outstanding borrowings under our lines of credit. In 2011, the proceeds from the issuance of $2.0 billion in senior notes and shares issued in 2011 were used to finance the ICG acquisition.We paid dividends of $25.5 million, $42.4 million, and $80.7 million during 2013, 2012, and 2011, reflecting a decrease in the dividend rate in the second quarter of 2012 from $0.11 to $0.03. Financial covenants associated with our term loan facility restrict the payment of dividends to $0.01 per year, and our board of directors has approved such dividend, payable in March.

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,				
	2013	2012	2011	2010	2009
Ratio of earnings to fixed charges[(1)]	N/A[(2)]	N/A[(2)]	1.25x	1.92x	0.75x

(1) Earnings consist of income from continuing 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 the ratio calculation were $638.3 million and total fixed charges were $450.7 million for the year ended December 31, 2013. Total losses for the ratio calculation were $711.2 million and total fixed charges were $367.2 million for the year ended December 31, 2012.

Contractual Obligations

	Payments Due by Period				
	2014	2015 - 2016	2017 - 2018	After 2018	Total
	(Dollars in thousands)				
Long-term debt, including related interest	$ 387,029	$ 774,322	$ 2,518,731	$ 3,564,945	$ 7,245,027
Operating leases	31,532	41,317	18,248	1,195	92,292
Coal lease rights	77,831	176,474	43,497	83,708	381,510
Coal purchase obligations	24,548	30,381	10,686		65,615
Unconditional purchase obligations	268,427	226,740	175,802	407,737	1,078,706
Total contractual obligations	$ 789,367	$ 1,249,234	$ 2,766,964	$ 4,057,585	$ 8,863,150

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The related interest on long-term debt was calculated using rates in effect at December 31, 2013 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 $427.7 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 $4.0 million to our pension plans in 2014, 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 $58.5 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.

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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, 2013:

	Reclamation Obligations	Lease Obligations	Workers' Compensation Obligations	Other	Total
	(Dollars in thousands)				
Self bonding	$ 417,618	$	$	$	$ 417,618
Surety bonds	247,284	55,437	28,784	9,047	340,552
Letters of credit	18,141		70,041	10,620	98,802

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, 2013, we had $33.9 million of surety bonds remaining related to Magnum properties.

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, 2013, 2012 and 2011.

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.

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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, 2013, our balance sheet reflected asset retirement obligation liabilities of $427.7 million, including amounts classified as a current liability. As of December 31, 2013, 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 Note 15 to the consolidated financial statements, "Asset Retirement Obligations".

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 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.

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We performed our annual impairment testing as of October 1, 2013 on the two Appalachia reporting units with remaining goodwill balances, the Leer mining complex and an undeveloped property adjacent to it. The fair values of these two reporting units are sensitive to the volatility in metallurgical coal demand. Continuing weakness in the metallurgical coal markets caused the Company to reassess key marketing and operating assumptions during the Company's annual budgeting process, which is the source of the projected cash flows for the goodwill impairment review. First, weakness in the metallurgical coal markets has continued longer than previously expected. After a slight improvement in the third quarter of 2013, metallurgical coal oversupply expectations weakened prices further in the fourth quarter of 2013, a situation expected to continue through 2014. Our long-term projections of market prices are based on internal estimates, which consider the trend expectations of third party sources, but are adjusted to reflect the assumptions of actual marketplace participants. Secondly, our expected product mix out of the Leer mine in the near term has changed compared to our previous assumptions to reflect more thermal coal commitments, due to the continuing oversupply in the metallurgical coal markets. Thirdly, the timing of development on the remaining property has been delayed, such that no development is expected to begin for five years. In addition to these changes resulting from the annual budgeting process, the fair values of the of the reporting units were also impacted by a higher base discount rates, due to higher costs of capital. The base rate was adjusted for each unit to reflect the risks inherent in the cash flow forecasts (other than coal pricing), like timing, production volumes and quality, and cost inflation.

As a result, the book values of the reporting units exceeded their fair values after the first step of the goodwill impairment tests. It was also determined that the fair value of goodwill had no value, and we recognized an impairment loss for the remaining reporting units totaling $265.4 million.

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 and 35% fixed income securities. 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% for 2013 and 2012, 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 2013 would have been an increase in expense of approximately $1.5 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

3.64%/4.58% (before/after Canyon Fuel sale) for 2013 and 4.91% for 2012. The impact of lowering the discount rate 0.5% for 2013 would have been an increase in expense of approximately $5.1 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 2013 year-end pension obligation and pension expense for 2014, we used a discount rate of 5.08%.

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 3.64%/4.58% (before/after Canyon Fuel sale) for 2013 and 4.52% for 2012, respectively. A change of 0.5% in these assumptions would not have a significant impact on the benefit costs in 2013.

For the measurement of our 2013 year-end other postretirement benefits obligation and postretirement expense for 2014, we used a discount rate of 4.58%.

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 fluctuations market pricing.

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Our sales commitments are as follows:

	2014		2015	
	Tons (in millions)	$ per ton	Tons (in millions)	$ per ton
Powder River Basin				
Committed, Priced	91.2	$ 13.18	52.4	$ 13.78
Committed, Unpriced	8.0		8.6	
Appalachia				
Committed, Priced Thermal	5.0	$ 57.07	1.9	$ 57.75
Committed, Unpriced Thermal	0.3			
Committed, Priced Metallurgical	3.5	$ 84.84	1.4	$ 87.01
Committed, Unpriced Metallurgical	0.7		0.2	
Other Bituminous				
Committed, Priced	3.9	$ 36.20	2.5	$ 38.95
Committed, Unpriced	0.6			

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, 2013. The estimated future realization of the value of the trading portfolio is $9.6 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, 2013, 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 $0.3 million. The final VaR at December 31, 2013 was $0.1 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, 2013 VaR for our risk management positions that are recorded at fair value through earnings ranged from $0.3 million to

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$1.9 million. The linear mean of each daily VaR was $1.0 million. The final VaR at December 31, 2013 was $0.3 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 pur