PEABODY ENERGY CORP
Form 10-K
February 27, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Fiscal Year Ended December 31, 2008
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 1-16463

Peabody Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware	**13-4004153**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
701 Market Street, St. Louis, Missouri	**63101**
(Address of principal executive offices)	*(Zip Code)*

(314) 342-3400
Registrant s telephone number, including area code

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	New York Stock Exchange
Preferred Share Purchase Rights	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 þ 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 þ

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 þ No o

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

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

Large accelerated filer þ	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 þ

Aggregate market value of the voting stock held by non-affiliates (shareholders who are not directors or executive officers) of the Registrant, calculated using the closing price on June 30, 2008: Common Stock, par value $0.01 per share, $23.9 billion.

Number of shares outstanding of each of the Registrant s classes of Common Stock, as of February 13, 2009: Common Stock, par value $0.01 per share, 267,362,965 shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company s Proxy Statement to be filed with the Securities and Exchange Commission in connection with the Company s 2009 Annual Meeting of Stockholders (the Company s 2009 Proxy Statement) are incorporated by reference into Part III hereof. Other documents incorporated by reference in this report are listed in the Exhibit Index of this Form 10-K.

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CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This report includes statements of our expectations, intentions, plans and beliefs that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 and are intended to come within the safe harbor protection provided by those sections. These statements relate to future events or our future financial performance, including, without limitation, the section captioned Outlook. We use words such as anticipate, believe, expect, may, project, should, estimate, or similar words to identify forward-looking statements.

Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings, and sources of funding are forward-looking statements and speak only as of the date of this report. These forward-looking statements are based on numerous assumptions that we believe are reasonable, but are subject to a wide range of uncertainties and business risks and actual results may differ materially from those discussed in these statements. Among the factors that could cause actual results to differ materially are:

- the duration and severity of the global economic downturn and disruptions in the financial markets;
- ability to renew sales contracts;
- reductions of purchases by major customers;
- credit and performance risks associated with customers, suppliers, trading and banks and other financial counterparties;
- transportation availability, performance and costs, including demurrage;
- availability, timing of delivery and costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires;
- geologic, equipment and operational risks inherent to mining;
- impact of weather on demand, production and transportation;
- legislation, regulations and court decisions or other government actions;
- new environmental requirements affecting the use of coal, including mercury and carbon dioxide related limitations;
- replacement of coal reserves;
- price volatility and demand, particularly in higher-margin products and in our trading and brokerage businesses;
- performance of contractors, third-party coal suppliers or major suppliers of mining equipment or supplies;
- negotiation of labor contracts, employee relations and workforce availability;
- availability and costs of credit, surety bonds, letters of credit, and insurance;

changes in postretirement benefit and pension obligations and funding requirements;

availability and access to capital markets on reasonable terms to fund growth and acquisitions;

the effects of acquisitions or divestitures;

economic strength and political stability of countries in which we have operations or serve customers;

risks associated with our Btu Conversion or generation development initiatives;

growth of United States and international coal and power markets;

coal s market share of electricity generation;

the availability and cost of competing energy resources;

successful implementation of business strategies;

the effects of changes in currency exchange rates, primarily the Australian dollar;

inflationary trends, including those impacting materials used in our business;

interest rate changes;

litigation, including claims not yet asserted;

terrorist attacks or threats;

impacts of pandemic illnesses; 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.

When considering these forward-looking statements, you should keep in mind the cautionary statements in this document and in our other Securities and Exchange Commission (SEC) filings. These forward-looking statements speak only as of the date on which such statements were made, and we undertake no obligation to update these statements except as required by federal securities laws.

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Note: The words we, our, Peabody or the Company as used in this report, refer to Peabody Energy Corporation or its applicable subsidiary or subsidiaries. Unless otherwise noted herein, disclosures in this Annual Report on Form 10-K relate only to our continuing operations. In 2008 we renamed our Eastern U.S. Mining segment to Midwestern U.S. Mining segment to better reflect the geography of the continuing operations of that region.

PART I

Item 1. *Business.*

Overview

We are the largest private-sector coal company in the world. During the year ended December 31, 2008, we sold 255.5 million tons of coal including 224.3 million tons from our United States (U.S.) and Australian mining operations and 31.2 million tons through our brokerage activities. During this period, we sold coal to 329 electricity generating and industrial plants in 21 countries. Our coal products fuel 10% of all U.S. electricity generation and 2% of worldwide electricity generation. At December 31, 2008, we had 9.2 billion tons of proven and probable coal reserves.

We own majority interests in 30 coal mining operations located in the U.S. and Australia. Additionally, we own a minority interest in one Venezuelan operating mine through a joint venture arrangement. We shipped 200.4 million tons from our 20 U.S. mining operations and 23.9 million tons from our 10 Australia operations in 2008. We shipped 85% of our U.S. mining operations coal sales volume from the western U.S. during the year ended December 31, 2008, and the remaining 15% from the midwestern U.S. In the western U.S., we own and operate mines in Arizona, Colorado, New Mexico and Wyoming. Over the last five years, our overall western U.S. coal production has increased from 129.6 million tons in 2003 to 169.9 million tons in 2008, a compound annual growth rate of 5.6%. Most of our production in the western U.S. is low-sulfur coal from the Powder River Basin. In the midwestern U.S., we own and operate mines in Illinois and Indiana. We also own 10 mines in Australia, five in Queensland and five in New South Wales. Our Australian production includes both low-sulfur domestic and export thermal (steam) and metallurgical coal products. The export thermal and metallurgical coal is predominantly shipped to customers in the Asia-Pacific region. For the year ended December 31, 2008, 90% of our global production was from non-union mines.

For the year ended December 31, 2008, 82% of our total sales (by volume) were to U.S. electricity generators, 16% were to customers outside the U.S. and 2% were to the U.S. industrial sector. Approximately 90% of our worldwide coal sales during 2008 were under long-term (one year or greater) contracts. Our sales backlog, including backlog subject to price reopener and/or extension provisions, was over one billion tons as of December 31, 2008, representing nearly five years of current production. Contracts in backlog have remaining terms ranging from one to 17 years. We are targeting 2009 production of 190 to 195 million tons in the U.S. and 22 to 24 million tons in Australia, including 6 to 7 million tons of metallurgical coal. As of January 27, 2009, our 2009 production is largely sold out in the U.S. with 4 to 5 million tons of Australian metallurgical coal and 5 to 6 million tons of Australian steam coal available to price.

Our mining operations consist of three principal operating segments: Western U.S. Mining, Midwestern U.S. Mining, and Australian Mining. In addition to our mining operations, we market, broker and trade coal through our Trading and Brokerage Operations segment. Our total tons traded were 192.9 million for the year ended December 31, 2008. Our international trading group has locations in London, England; Newcastle, Australia; and Beijing, China. Our China office also engages in sales, marketing and business development to pursue potential long-term growth opportunities there. Our other energy-related commercial activities include expansion of our Australian export capability with a 17.7% sponsorship of the Newcastle Infrastructure Group terminal currently under construction, as well as the management of our vast coal reserve and real estate holdings through initiatives such as 1) participation in developing mine-mouth coal-fueled generating plants; 2) developing Btu Conversion technologies, which are designed to convert coal to natural gas and transportation fuels; and 3) advancing carbon capture sequestration initiatives in the U.S., China and Australia.

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For financial information regarding each of our operating segments, see Note 22 to our consolidated financial statements.

Discontinued Operations

In 2007, we spun off portions of our formerly Eastern U.S. Mining segment through a dividend of all outstanding shares of Patriot Coal Corporation (Patriot), which is now an independent public company traded on the New York Stock Exchange (symbol PCX). The spin-off included eight company-operated mines, two joint venture mines, and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Our results for all periods presented reflect Patriot as a discontinued operation.

We also have classified as discontinued operations those operations recently divested, as well as certain non-strategic mining assets held for sale where we have committed to the divestiture of such assets. The results of operations relating to these items are classified as discontinued operations for all periods presented.

History

Peabody, Daniels and Co. was founded in 1883 as a retail coal supplier, entering the mining business in 1888 as Peabody & Co. with the opening of our first coal mine in Illinois. In 1926, Peabody Coal Company was listed on the Chicago Stock Exchange and, beginning in 1949, on the New York Stock Exchange.

In 1955, Peabody Coal Company, primarily an underground mine operator, merged with Sinclair Coal Company, a major surface mining company. Peabody Coal Company was acquired by Kennecott Copper Company in 1968. The company was then sold to Peabody Holding Company in 1977, which was formed by a consortium of companies.

During the 1980s, Peabody grew through expansion and acquisition, opening the North Antelope Mine in Wyoming s coal-rich Powder River Basin in 1983 and the Rochelle Mine in 1985.

In July 1990, Hanson PLC acquired Peabody Holding Company. In the 1990s, Peabody continued to grow through expansion and acquisitions. In February 1997, Hanson spun off its energy-related businesses, including Eastern Group and Peabody Holding Company, into The Energy Group PLC. The Energy Group was a publicly traded company in the United Kingdom and its American Depository Receipts (ADRs) were publicly traded on the New York Stock Exchange.

In May 1998, Lehman Brothers Merchant Banking Partners II L.P. and affiliates (Merchant Banking Fund), an affiliate of Lehman Brothers Inc. (Lehman Brothers), purchased Peabody Holding Company and its affiliates, Peabody Resources Limited and Citizens Power LLC in a leveraged buyout transaction that coincided with the purchase by Texas Utilities of the remainder of The Energy Group. In August 2000, Citizens Power, our subsidiary that marketed and traded electric power and energy-related commodity risk management products, was sold to Edison Mission Energy and in January 2001, we sold our Peabody Resources Limited (in Australia) operations to Coal & Allied, a subsidiary of Rio Tinto Limited.

In April 2001, we changed our name to Peabody Energy Corporation, reflecting our position as a premier energy supplier. In May 2001, we completed an initial public offering of common stock, and our shares began trading on the New York Stock Exchange under the ticker symbol BTU, the globally recognized symbol for energy.

In April 2004, we acquired coal operations from RAG Coal International AG, expanding our presence in both Australia and Colorado. In December 2004, we completed the purchase of a 25.5% equity interest in Carbones del Guasare from RAG Coal International, S.A. Carbones del Guasare, a joint venture with Anglo American plc and a

Venezuelan governmental partner, operates Venezuela s largest coal mine, the Paso Diablo Mine in northwestern Venezuela. In October 2006, we expanded our presence in Australia with the acquisition of Excel Coal Limited (Excel), an independent coal company in Australia. The Excel acquisition included operating and development-stage mines, along with proven and probable coal reserves of up to 500 million tons.

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In October 2007, we spun off portions of our formerly Eastern U.S. Mining operations business segment to form Patriot, as discussed above.

In 2008, we began shipping coal from our new El Segundo Mine in New Mexico, which is expected to produce 6 million tons of coal annually. We purchased the remaining 15.4% share of the Millennium Mine in Queensland, Australia from the former minority shareholders for $110.1 million. In early 2009, we obtained an option to purchase up to a 50% interest in a joint venture holding Polo Resources Limited s (AIM: PRL) coal and mineral interests in Mongolia as well as warrants to enable us to acquire an approximate 15% equity interest in Polo Resources Limited. Mongolia is known for its metallurgical and thermal coal resources.

We have transformed in recent years from a high-sulfur, high-cost coal company to a predominately low-sulfur, low-cost coal producer, marketer/trader of coal and manager of vast natural resources through organic growth, acquisitions, divestitures and strategic operational restructuring. We have four core strategies to achieve growth:

1. Executing the basics of best-in-class safety, operations and marketing;

2. Capitalizing on organic growth opportunities;

3. Expanding in high-growth global markets; and

4. Participating in new generation and Btu Conversion technologies to convert coal into natural gas and transportation fuels.

Mining Operations

We conduct our mining business through three principal mining operating segments: Western U.S. Mining, Midwestern U.S. Mining, and Australian Mining. Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado operations, and our Midwestern U.S. Mining operations consist of our Illinois and Indiana operations. The principal business of our U.S. Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities. Internationally, we operate metallurgical and thermal coal mines in Queensland and New South Wales, Australia and have a 25.5% investment in a Venezuelan mine. All of our operating segments are discussed in Note 22 to our consolidated financial statements.

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The following describes the operating characteristics of the principal mines and reserves of each of our business units and affiliates. The maps below show mine locations as of December 31, 2008. All of our mining operations are owned and managed by our subsidiaries. The subsidiary that manages a particular mining operation is not necessarily the same as the subsidiary or subsidiaries which own the assets utilized in that mining operation. Unless otherwise indicated, we own 100% of the subsidiary that manages the respective mining operations or owns the related assets.

U.S. Mining Operations

Powder River Basin Operations

We control approximately 3.2 billion tons of proven and probable coal reserves in the Powder River Basin, the largest and fastest growing major U.S. coal-producing region. We manage three low-sulfur, non-union surface mining complexes in Wyoming that sold 147.1 million tons of coal during the year ended December 31, 2008, or approximately 58% of our total coal sales volume.

Our Wyoming Powder River Basin reserves are classified as surface mineable, subbituminous coal with seam thickness varying from 60 to 115 feet. The sulfur content of the coal in current production ranges from 0.2% to 0.4% and the heat value ranges from 8,100 to 8,800 Btu s per pound.

North Antelope Rochelle Mine

The North Antelope Rochelle Mine is located 65 miles south of Gillette, Wyoming. This coal mine is the largest in the world, selling 97.5 million tons of compliance coal (defined as having sulfur dioxide content of 1.2 pounds or less per million Btu) during 2008. The North Antelope Rochelle Mine produces premium quality coal with a sulfur content averaging 0.2% and a heat value ranging from 8,600 to 8,800 Btu per pound. The North Antelope Rochelle Mine traditionally produces the lowest sulfur coal in the U.S., using three draglines along with five overburden truck-and-shovel fleets and is serviced by both major western railroads, the Burlington Northern Santa Fe (BNSF) Railway and the Union Pacific Railroad. In 2008, we completed new blending and loading facilities that are designed to result in a lower cost structure while also increasing capacity.

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Caballo Mine

The Caballo Mine is located 20 miles south of Gillette, Wyoming. During 2008, it sold 31.2 million tons of compliance coal. Caballo is a cast/dozer/truck-and-shovel assist operation with a coal handling system that includes two 12,000-ton silos and two 11,000-ton silos and is serviced by both major western railroads, the BNSF Railway and the Union Pacific Railroad. The Caballo Mine produces compliance coal with a sulfur content averaging 0.34% and a heat value averaging 8,100 Btu per pound.

Rawhide Mine

The Rawhide Mine is located 10 miles north of Gillette, Wyoming. During 2008, it sold 18.4 million tons of compliance coal. Rawhide is a cast/dozer-push/truck-and-shovel assist operation with a coal handling system that includes two 12,000-ton silos and four 11,000-ton silos and is serviced by the BNSF Railway. The Rawhide Mine produces compliance coal with a sulfur content averaging 0.36% and a heat value averaging 8,300 Btu per pound.

Southwest Operations

We own four coal mines in our Southwest operations, two in Arizona and two in New Mexico. Kayenta, in Arizona, and Lee Ranch and El Segundo in New Mexico, are all in operation, while the Black Mesa Mine in Arizona suspended operations as of December 31, 2005. We control 1.0 billion tons of proven and probable coal reserves in our Southwest operations.

Kayenta Mine

The Kayenta Mine, located on the Navajo Nation and Hopi Tribe lands in Arizona, uses four draglines in three mining areas. It sold approximately 8.0 million tons of coal during 2008 and supplies primarily bituminous compliance coal under a long-term coal supply agreement to an electricity generating station in the region. The coal is crushed, then carried 17 miles by conveyor belt to storage silos where it is loaded onto a private rail line and transported 83 miles to the Navajo Generating Station, operated by the Salt River Project near Page, Arizona. The mine and railroad were designed to deliver coal exclusively to the power plant, which has no other source of coal. The Navajo coal supply agreement extends until 2011. Hourly workers at this mine are members of the United Mine Workers of America (UMWA) under a contract that extends through 2013.

Lee Ranch Mine

The Lee Ranch Mine, located near Grants, New Mexico, sold approximately 3.4 million tons of subbituminous medium sulfur coal during 2008. Lee Ranch shipped the majority of its coal to two customers in New Mexico and Arizona under coal supply agreements extending until 2014 and 2020, respectively. Lee Ranch is a non-union surface mine that uses a combination of dragline and truck-and-shovel mining techniques and ships coal to its customers via the BNSF Railway.

El Segundo Mine

The El Segundo Mine, located near Grants, New Mexico, started producing subbituminous medium sulfur coal in mid-2008 and sold approximately 2.6 million tons in 2008. El Segundo is a non-union surface mine that uses truck-and-shovel mining techniques and ships coal to its customers via the BNSF Railway.

Colorado Operations

We control approximately 0.2 billion tons of proven and probable coal reserves and have one operating mine in the Colorado Region.

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Twentymile Mine

The Twentymile Mine is located in Routt County, Colorado and sold 8.6 million tons of compliance, low-sulfur, steam coal to customers throughout the U.S. during 2008. Our Twentymile Mine is a non-union longwall operation and is one of the largest underground mines in the U.S. Approximately 75% of all coal shipped is loaded on the Union Pacific railroad; the remainder is hauled by truck to the nearby Hayden Generating Station, operated by the Public Service of Colorado, under a coal supply agreement that extends until 2011.

Midwest Operations

Our Midwest operations consist of 13 mines in Illinois and Indiana. We control approximately 3.7 billion tons of proven and probable coal reserves in the Midwest. In 2008, these operations collectively sold 30.7 million tons of coal (including purchased coal), more than any other Illinois Basin coal producer (which covers portions of Illinois, Indiana and Kentucky). We ship coal from these mines primarily to electricity generators in the Midwest and to industrial customers for power generation.

Gateway Mine

The Gateway Mine is a non-union underground mine located in Randolph County, Illinois. During 2008, the Gateway Mine sold 3.2 million tons of steam coal. Coal from the Gateway Mine is shipped by rail direct to customers plants, by rail and barge for customers located on the Ohio and Mississippi rivers, and by truck to certain industrial customers.

Air Quality Mine

The Air Quality Mine is an underground mine located near Monroe City, Indiana that sold 1.9 million tons of compliance coal in 2008. The Air Quality Mine has a non-union workforce. Coal is shipped from the Air Quality Mine by truck, by truck and rail, and by truck and barge.

Farmersburg Mine

The Farmersburg Mine is a surface mine located in Vigo and Sullivan counties in Indiana that sold 3.3 million tons of medium sulfur coal in 2008. The Farmersburg Mine has a non-union workforce. Coal is shipped from the Farmersburg Mine by rail and by truck to customers plants.

Francisco Mine Complex

The Francisco Mine Complex, which has both an underground and surface mine, is located in Gibson County, Indiana and sold 3.4 million tons of medium sulfur coal in 2008. The Francisco Mine Complex has a non-union workforce and ships coal by rail to utility customers plants.

Somerville Mine Complex

The Somerville Mine Complex consists of three surface mines located in Gibson County, Indiana. These mines collectively sold 7.9 million tons of medium sulfur coal in 2008. The Somerville Mine Complex has a non-union workforce and ships coal by rail, truck and rail, and truck and barge.

Viking Mine

The Viking Mine is a surface mine located in Indiana that sold 1.6 million tons of medium sulfur coal in 2008. The Viking Mine has a non-union workforce and ships coal by truck and rail to customers plants.

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Miller Creek Mine

The Miller Creek Mine is a surface mine located in Indiana that sold 1.8 million tons of medium sulfur coal in 2008. The Miller Creek Mine has a non-union workforce and ships coal by truck and by truck and rail to customers   plants.

Wildcat Hills Mine Complex

The Wildcat Hills Mine Complex, which has both an underground and surface mine, is located in Gallatin and Saline counties in southern Illinois. During 2008, these mines sold 3.0 million tons of medium sulfur coal that is primarily shipped by barge to downriver utility plants. The Wildcat Hills Mine Complex has a non-union workforce.

Willow Lake Mine

The Willow Lake Mine is an underground mine in southern Illinois. During 2008, the mine sold 3.7 million tons of medium sulfur coal that is primarily shipped by barge to downriver utility plants. The hourly workforce at the Willow Lake Mine is represented under an International Brotherhood of Boilermakers labor agreement, which will expire April 15, 2011.

Australian Mining Operations

We manage five mines in Queensland, Australia, and five mines in New South Wales, Australia. During 2008, our Australian operations sold 23.9 million tons of coal, 8.3 millions tons of which were metallurgical coal. Coal from the Queensland mines is shipped via rail and truck to the Dalrymple Bay Coal Terminal and the Port of Brisbane, where the coal is loaded onto ocean-going vessels. Coal from the New South Wales mines is shipped via rail and truck to domestic customers and to the Ports of Newcastle and Kembla. Most of the sales from our Australian mines are denominated in U.S. dollars. Our Australian mines operate with site-specific collective bargaining labor agreements. Our Australian operations control 1.1 billion tons of proven and probable coal reserves.

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Wilkie Creek Mine

The Wilkie Creek Mine, located in Queensland, Australia, is a surface, truck-and-shovel operation. In 2008, the Wilkie Creek Mine sold 2.5 million tons of thermal coal, all of which was sold to the Asian export market through the Port of Brisbane.

Burton Mine

The Burton Mine, located in Queensland, Australia, is a surface mine using the truck-and-shovel terrace mining technique. We own 95% of the Burton operation and the remaining 5% interest is owned by the contract miner that operates on reserves we control. During 2008, we sold 2.6 million tons of metallurgical coal and 0.1 million tons of thermal coal from the Burton Mine through the Dalrymple Bay Coal Terminal.

Millennium Mine

The Millennium Mine, located in Queensland, Australia, began operations in 2007 and is a surface operation utilizing truck-and-shovel mining methods. We manage this mine utilizing a contract miner. In 2008, we purchased the remaining 15.4% share of the Millennium Mine from the former minority shareholders. During 2008, the Millennium Mine sold 1.3 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

North Goonyella Mine

The North Goonyella Mine, located in Queensland, Australia is a longwall underground operation that produces metallurgical coal. During 2008, the North Goonyella Mine sold 1.8 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

Eaglefield Mine

The Eaglefield Mine, located in Queensland, Australia, is a surface operation utilizing truck-and-shovel mining methods. It is adjacent to, and fulfills contract tonnages in conjunction with, the North Goonyella underground mine. Coal is mined by a contractor from reserves that we control. During 2008, the Eaglefield Mine sold 1.2 million tons of metallurgical coal through the Dalrymple Bay Coal Terminal.

Wambo Open-Cut Mine

The Wambo Open-Cut Mine, located in New South Wales, Australia, is a surface operation utilizing truck-and-shovel mining methods. During 2008, the Wambo Open-Cut Mine sold 3.0 million tons of thermal coal. The coal from this mine was shipped through the Port of Newcastle. We have a 100% interest in the Wambo Open-Cut Mine, but only retain 75% of profits as part of a profit sharing interest with the non-voting minority owner. The mine s operations are managed utilizing a contract miner.

North Wambo Underground Mine

The North Wambo Underground Mine, located in New South Wales, Australia, is a longwall underground mine which was commissioned in 2007. During 2008, the North Wambo Underground Mine sold 2.2 million tons of thermal coal. The coal from this mine was shipped through the Port of Newcastle. We have a 100% interest in the Wambo Underground Mine, but only retain 75% of profits as part of a profit sharing interest with the non-voting minority owner.

Metropolitan Mine

The Metropolitan Mine, located in New South Wales, Australia, is a longwall underground operation. In 2008, the Metropolitan Mine sold 1.4 million tons of metallurgical coal. Coal shipments from this mine are to export customers through Port Kembla and to an Australian customer.

Wilpinjong Mine

The Wilpinjong Mine, located in New South Wales, Australia, is a surface mine that was commissioned in 2006. The mine produces thermal coal for export customers through the Port of Newcastle in addition to serving an Australian electricity generator. Coal is mined by a contractor from reserves that we control. During 2008, the Wilpinjong Mine sold 7.3 million tons of thermal coal.

Chain Valley Mine

The Chain Valley Mine located in New South Wales, Australia, is a room and pillar underground operation. The Chain Valley Mine produces thermal coal which is sold locally to power authorities and to export customers through the Port of Newcastle. During 2008, the Chain Valley Mine sold 0.5 million tons of thermal coal for the year. We own 80% of the Chain Valley Mine.

Venezuelan Mining Operation

Paso Diablo Mine

We own a 25.5% interest in Carbones del Guasare, S.A., a joint venture that includes Anglo American plc and a Venezuelan governmental partner. Carbones del Guasare operates the Paso Diablo Mine in Venezuela. The Paso Diablo Mine is a surface operation in northwestern Venezuela that produced approximately 4.8 million tons of steam coal in 2008 for export primarily to the U.S. and Europe. We are responsible for marketing our pro-rata share of sales from Paso Diablo; the joint venture is responsible for production, processing and transportation of coal to ocean-going vessels for delivery to customers.

Export Facilities

We own a 37.5% interest in Dominion Terminal Associates, a partnership that leases a coal export terminal from the Peninsula Ports Authority of Virginia in Newport News, Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The facility has a rated throughput capacity of approximately 20 million tons of coal per year and had 13.7 million tons of throughput in 2008. The facility also has ground storage capacity of approximately 1.7 million tons. The facility exports both metallurgical and steam coal primarily to European and Brazilian markets.

We own a 17.7% interest in the Newcastle Coal Infrastructure Group, which is currently constructing a coal transloading facility in Newcastle, Australia. The facility, which is expected to be completed in 2010, will be backed by take or pay agreements and will have an initial stage capacity of 33 million tons per annum of which our share is 5.8 million tons, with expansion capacity of up to 66 million tons per annum.

Resource Management

We hold approximately 9.2 billion tons of proven and probable coal reserves and more than 500,000 acres of surface property. Our resource development group regularly reviews these reserves for opportunities to generate earnings and cash flow through the sale of non-strategic coal reserves and surface land. In addition, we generate revenue through royalties from coal reserves and oil and gas rights leased to third parties, and farm income from surface land under third-party contracts.

Trading and Brokerage Operations

Through our Trading and Brokerage segment, we primarily broker coal sales of other coal producers both as principal and agent, and trade coal, freight and freight-related contracts. We also provide transportation-related services in support of our coal trading strategy, as well as hedging activities in support of our mining operations.

In response to growing international markets, we expanded our international trading group in 2006 and added a trading operations office in London in 2007. The sales and marketing operations include our COALTRADE Australia and COALTRADE International operations that broker coal in the Australia and

Pacific Rim markets. We also have a sales, marketing and business development office in Beijing, China to pursue potential long-term growth opportunities in this market.

Coal Supply Agreements

As of December 31, 2008, we had a sales backlog of over one billion tons of coal, including backlog subject to price reopener and/or extension provisions, representing nearly five years of current production in backlog. Agreements in backlog have remaining terms ranging from one to 17 years. As of December 31, 2007, we had a sales backlog of almost one billion tons of coal. For 2008, we sold approximately 90% of our worldwide sales volume under long-term coal supply agreements. In 2008, we sold coal to 329 electricity generating and industrial plants in 21 countries.

U.S.

We expect to continue selling a significant portion of our coal under long-term supply agreements. Customers continue to pursue long-term sales agreements as the importance of reliability, service and predictable prices are recognized. The terms of coal supply agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these agreements vary significantly in many respects, including price adjustment features, price reopener terms, coal quality requirements, quantity parameters, permitted sources of supply, treatment of environmental constraints, extension options, force majeure, and termination and assignment provisions. Our strategy is to selectively renew, or enter into new, long-term supply agreements when we can do so at prices we believe are favorable.

Australia

Our international coal mining activities accounted for 11% of our mining operations sales volume in 2008. Our production is sold primarily into the export metallurgical and thermal markets. Price reopener provisions are present in the majority of our multi-year international coal agreements. Typically, these provisions allow either party to commence a renegotiation of the agreement price annually. A majority of the reopener provisions relate to metallurgical coal repriced annually in the second quarter of each year. We also have a long-term coal supply agreement with Macquarie Generation in Australia, which runs through 2025 and will supply approximately 127 million tons in total from our Wilpinjong Mine.

Transportation

Coal consumed in the U.S. is usually sold at the mine with transportation costs borne by the purchaser. Export coal is usually sold at the loading port, with purchasers paying ocean freight. Producers usually pay shipping costs from the mine to the port, including any demurrage costs (fees paid to third-party shipping companies for loading time that exceeded the stipulated time). We believe we have good relationships with rail carriers and barge companies due, in part, to our modern coal-loading facilities and the experience of our transportation coordinators.

The majority of our sales volume is shipped by rail in the U.S., but a portion of our production is shipped by other modes of transportation, including barge, truck and ocean-going vessels. Our transportation department manages the loading of coal via these transportation modes.

Our Australian export volume (18 to 19 million tons annually) is shipped via ocean going vessels to customers. The majority of this coal reaches the loading port via rail. The majority of our Australian domestic volume (4 to 5 million tons annually) is shipped via rail.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, ammonium-nitrate based explosives, diesel fuel, off-the-road (OTR) tires, steel-related (including roof control materials) products and lubricants. Although we have many well-established, strategic relationships with our key suppliers, we do not believe that we are dependent on any of our individual suppliers, except as noted below. The supplier base providing mining materials has been relatively consistent in recent years, although there continues to be some consolidation. Consolidation of suppliers of explosives has limited the number of sources for these materials. Although our current U.S. supply of explosives is concentrated with two suppliers (one primary and one smaller secondary), some alternative sources are available to us in the regions where we operate. Further consolidation of underground equipment suppliers has resulted in a situation where purchases of certain underground mining equipment are concentrated with one principal supplier; however, some supplier competition continues to be present. In recent years, demand and lead times for certain surface and underground mining equipment and OTR tires had increased. However, as a result of the global economic slowdown in the last half of 2008, lead times for nearly all items have been decreasing. We do not expect lead times to have a near-term material impact on our financial condition, results of operations or cash flows.

Technical Innovation

We continue to place great emphasis on the application of technical innovation to improve new and existing equipment performance. This research and development effort is typically undertaken and funded by equipment manufacturers using our input and expertise. Our engineering, maintenance and purchasing personnel work together with manufacturers to design and produce equipment that we believe will add value to the business. A recent example of this is a collaboration with a third party and two universities to develop and test a programmable fuel controller for diesel mining equipment to reduce fuel consumption and particulate emissions without loss of performance.

During 2008, three major equipment and infrastructure upgrades were completed at North Antelope Rochelle Mine, our largest operation. A new dragline was commissioned with more efficient bucket design, faster cycle times, improved swing motion controls to increase component life and better monitors to enable increased payloads. A new overland conveyor and near pit truck dump and crusher facility were built to reduce truck haulage, conserve fuel and increase mine capacity. New high capacity blending and loading facilities were also completed that are designed to result in a lower cost structure while also increasing capacity.

Technology to quickly capture, analyze and transfer information regarding safety, performance and maintenance conditions at our operations is a priority. A wireless data acquisition system was installed at the Caballo Mine to more efficiently dispatch mobile equipment and monitor performance and condition of all major mining equipment on a real-time basis. This system has been performing well for two years at the nearby North Antelope Rochelle Mine. In addition, we have deployed at our North Antelope Rochelle Mine a component of our Enterprise Resource Planning system that connects to an application allowing us to collect equipment performance data and mine shipments detail in real-time. Also at our North Antelope Rochelle Mine and Caballo Mine, we have upgraded our wireless networks in support of a fully integrated mining data system. Proprietary software for hand-held Personal Digital Assistant devices was developed in-house, and has been deployed at all U.S. underground mines to record safety observations, safety audits, underground front-line supervisor reports and delay information.

We use maintenance standards based on reliability-centered maintenance practices at all operations. Use of these techniques allows us to increase equipment utilization and reduce maintenance and capital spending by extending the equipment life, while minimizing the risk of premature failures. Optimized equipment strategies are being developed to help identify the appropriate preventative and predictive maintenance activities, emphasizing work being scheduled on condition rather than time. Benefits from analysis derived from lubrication, vibration and infrared technologies typically include lower lubrication consumption, better equipment performance and extended component life. Specialized maintenance reliability software is used at many operations to better support improved equipment strategies, predict equipment condition and aid analysis necessary for better decision-making for such issues as component replacement timing.

Our mines use software to schedule and monitor trains, mine and pit blending, quality and customer shipments. This software was developed in-house and provides a competitive tool to differentiate our reliability and product consistency. Our preparation plant at the Twentymile Mine in Colorado utilizes low profile design and high capacity equipment for improved maintenance practices and overall plant utilization. The process circuitry uses large diameter heavy media cyclones and two stage fine coal cleaning with water-only cyclones and spirals to enhance process performance and yield. A number of safety and monitoring features have been incorporated in the plant including an internet-accessible camera system.

We are also contributing to the commercial development and advancement of Btu Conversion technologies (see the Generation Development, Btu Conversion and Clean Coal Technology discussion that follows for more details).

Competition

The markets in which we sell our coal are highly competitive. According to the National Mining Association s 2007 Coal Producer Survey, the top 10 coal companies in the U.S. produced approximately 66% of total U.S. coal in 2007. Our principal U.S. competitors are other large coal producers, including Arch Coal, Inc., Rio Tinto Energy America, CONSOL Energy Inc. and Foundation Coal Corporation, which collectively accounted for approximately 35% of total U.S. coal production in 2007. Major international competitors include Rio Tinto, Anglo-American PLC, BHP Billiton, Shenhua Group, China Coal and Xstrata PLC.

A number of factors beyond our control affect the markets in which we sell our coal. Continued demand for our coal and the prices obtained by us depend primarily on the coal consumption patterns of the electricity generation and steel industries in the U.S., China, India and elsewhere around the world; the availability, location, cost of transportation and price of competing coal; and other electricity generation and fuel supply sources such as natural gas, oil, nuclear, hydroelectric, and other renewables. Coal consumption patterns are affected primarily by the demand for electricity, environmental and governmental legislation and regulations, and technological developments. We compete on the basis of coal quality, delivered price, customer service and support, and reliability.

Generation Development, Btu Conversion and Clean Coal Technology

To maximize our coal assets and land holdings for long-term growth, we are contributing to the development of coal-fueled generation, pursuing Btu Conversion projects that would convert coal to natural gas or transportation fuels and taking a leading position in advancing clean coal technologies.

Generation development projects involve using our surface lands and coal reserves as the basis for mine-mouth plants. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal lessor.

> ***Prairie State*** We are currently a 5.06% owner in the Prairie State Energy Campus (Prairie State), a 1,600 megawatt coal-fueled electricity generation project under construction in Washington County, Illinois. Prairie State will be fueled by over six million tons of coal each year produced from its adjacent underground mining operations. We sold 94.94% of the land and coal reserves to our partners in Prairie State and we are responsible for our 5.06% share of costs to construct the facility. The plant is scheduled to begin generating electricity in the 2011 to 2012 timeframe.

The U.S. Energy Information Administration estimates prices for oil and natural gas in 2030 will be materially higher than 2007 levels: imported crude oil prices are projected to increase 94% and domestic natural gas prices are forecasted to rise more than 30%. We are determining how to best participate in Btu Conversion technologies to economically convert our coal resources to natural gas and transportation fuels.

> ***Kentucky NewGas (U.S.)*** In 2008, we entered into an agreement with ConocoPhillips to explore development of a commercial scale coal-to-substitute natural gas facility at a site near Central City, Kentucky, in Muhlenberg County. The project recently submitted an application for its air permit. The permitting phase is expected to take between 12 to 18 months, subject to government approvals.

GreatPoint Energy (U.S.) We own a minority investment in GreatPoint Energy, Inc., which is commercializing its proprietary bluegas^{tm} technology that converts coal, petroleum coke and biomass into ultra-clean pipeline quality natural gas while enabling carbon capture and storage.

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We are advancing the development of clean coal technologies, including carbon capture and sequestration, through a number of initiatives.

FutureGen Industrial Alliance (U.S.) We are a founding member of the FutureGen Industrial Alliance (FutureGen), a non-profit company that is partnering with the U.S. Department of Energy (DOE) to facilitate the design, construction and operation of the world s first near-zero emissions coal-fueled power plant. The FutureGen project development schedule is pending release of a record of a decision on the environmental impact statement and funding appropriations.

GreenGen (China) In December 2007, we became the only non-Chinese equity partner in GreenGen, a development-stage project in China to build a near-zero emissions coal-fueled power plant with carbon capture and storage. The GreenGen project is expected to use advanced coal-based technologies to generate electricity. It would be capable of hydrogen production and will advance carbon dioxide capture and storage technologies. Construction is expected to begin in March 2009.

COAL21 Fund (Australia) We have committed to contribute for a ten-year period to the Australian COAL21 Fund, which is a voluntary coal industry fund to support clean coal technology demonstration projects and research in Australia. All major coal companies in Australia have committed to this fund. The Clean Coal Technology Special Agreement Act 2007 (Queensland) provides that the amount contributed in relation to Queensland production will be expended on Queensland or National Clean Coal Technology Projects. The Act establishes a Clean Coal Council to make project funding recommendations to the Premier.

University Research Programs (U.S.) We are also participating in multiple university research partnerships by funding multi-year grants. These university initiatives are focused on advancing clean coal research and mining technologies.

Certain Liabilities

We have long-term liabilities for reclamation (also called asset retirement obligations), pensions and retiree health care. In addition, one labor contract with the UMWA (the Western Surface Agreement) and voluntary arrangements with non-union employees include long-term benefits, notably health care coverage for retired employees and future retirees and their dependents. The majority of our existing liabilities relate to our past operations, including operations spun off with Patriot.

Asset Retirement Obligations. Asset retirement obligations primarily represent the present value of future anticipated costs to restore surface lands to productivity levels equal to or greater than pre-mining conditions, as required by applicable laws and regulations. Expense from continuing operations (which includes liability accretion and asset amortization) for the years ended December 31, 2008, 2007 and 2006 was $48.2 million, $23.7 million, and $14.2 million, respectively. As of December 31, 2008, our asset retirement obligations of $422.6 million included $387.2 million related to locations with active mining operations and $35.4 million related to locations that are closed or inactive.

Pension-Related Provisions. Pension-related costs represent the actuarially-estimated cost of pension benefits. Annual minimum contributions to the pension plans are determined by consulting actuaries based on the minimum funding standards of the Employee Retirement Income Security Act of 1974, as amended (ERISA), and an agreement with the Pension Benefit Guaranty Corporation (PBGC). On January 1, 2008, new minimum funding standards were required by the Pension Protection Act of 2006. Net pension-related liabilities were $216.0 million as of December 31, 2008, $1.6 million of which was a current liability. Net pension cost reflects a benefit of $7.4 million for the year ended December 31, 2008 and expense of $19.6 million and $26.3 million for the years ended December 31, 2007 and 2006, respectively.

Retiree Health Care. Consistent with Statement of Financial Accounting Standard (SFAS) No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions we record a liability representing the estimated cost of providing retiree health care benefits to current retirees and active employees who will retire in the future. Provisions for active employees represent the amount recognized to date, based on their service to date; additional amounts are accrued periodically so that the total estimated liability is accrued when

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the employee retires. Our retiree health care liabilities were $833.4 million as of December 31, 2008, $67.3 million of which was a current liability. In 2007, we spun off Patriot. Retiree health care expense related to the spin-off of Patriot for the years ended December 31, 2007 and 2006 was $46.6 million and $41.4 million, respectively, and was included in Discontinued operations.

Employees

As of December 31, 2008, we had approximately 7,200 employees. As of such date, approximately 28% of our hourly employees were represented by organized labor unions and generated 10% of the 2008 coal production. Relations with our employees and, where applicable, organized labor are important to our success.

U.S. Labor Relations

Hourly workers at our Kayenta Mine in Arizona are represented by the UMWA, under the Western Surface Agreement, which is effective through September 2, 2013. This agreement covers approximately 7% of our U.S. subsidiaries hourly employees, who generated approximately 4% of our U.S. production during the year ended December 31, 2008. Hourly workers at our Willow Lake Mine in Illinois are represented by the International Brotherhood of Boilermakers, under a labor agreement that expires April 15, 2011. This agreement covers approximately 8% of our U.S. subsidiaries hourly employees, who generated approximately 2% of our U.S. production during the year ended December 31, 2008.

Australia Labor Relations

The Australian coal mining industry is unionized and the majority of workers employed at our Australian Mining operations are members of trade unions. The Construction Forestry Mining and Energy Union represents our Australian subsidiary s hourly production employees, including those employed through contract mining relationships. The labor agreements at our Australian subsidiary s Metropolitan Mine were renewed in 2007 and expire in 2010. The labor agreements at our Australian subsidiary s Chain Valley Mine and Wambo Mine coal handling plant were renewed in 2008 and expire in 2011. The labor agreements for our Australian subsidiary s Wambo Underground Mine and North Goonyella Mine are under negotiation. The Wambo Underground Mine agreement expired in November 2008 while the North Goonyella Mine s existing agreement expires in May 2009.

Regulatory Matters U.S.

Federal, state and local authorities regulate the U.S. coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, the reclamation and restoration of mining properties after mining has been completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects of mining on groundwater quality and availability. In addition, the industry is affected by significant legislation mandating certain benefits for current and retired coal miners. Numerous federal, state and local governmental permits and approvals are required for mining operations. We believe that we have obtained all permits currently required to conduct our present mining operations.

We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time in the industry. None of the violations to date or the monetary penalties assessed has been material.

Mine Safety and Health

Our goal is to provide a workplace that is incident free. We believe that it is our responsibility to our employees to provide a superior safety and health environment. We seek to implement this goal by: training employees in safe work practices; openly communicating with employees; establishing, following and improving safety standards; involving employees in safety processes; and recording, reporting and investigating all accidents, incidents and losses to avoid reoccurrence. A portion of the annual performance incentives for our operating units is tied to their safety performance.

During 2008, our safety performance set a new standard in our 125-year history. The U.S. injury incidence rate of 1.7 (computed per 200,000 worker hours) for 2008 was 34% better than the previous year and more than 61% better than the U.S. average for our industry. All of the operating regions showed incidence rate improvements in 2008, and more importantly, there were no fatal accidents at any of our facilities. We received multiple state and federal safety awards during the year. Our training centers educate our employees in safety best practices and reinforce our company-wide belief that productivity and profitability follow when safety is the cornerstone at all of our operations.

Stringent health and safety standards have been in effect since Congress enacted the Coal Mine Health and Safety Act of 1969. The Federal Mine Safety and Health Act of 1977 significantly expanded the enforcement of safety and health standards and imposed safety and health standards on all aspects of mining operations. Congress enacted The Mine Improvement and New Emergency Response Act of 2006 (The Miner Act) as a result of the increase in fatal accidents primarily at U.S. underground mines. Among the new requirements, each miner must have at least two, one-hour Self Contained Self Rescue (SCSR) devices for their use in the event of an emergency (each miner had at least one SCSR device prior to The Miner Act) with additional caches of SCSRs in the escape routes leading to the surface. Also, refuge chambers have been installed in all of our U.S. underground mines to protect miners who may become trapped in the event of an emergency. The Miner Act requires the installation of wireless, two-way communication systems for miners, and mine operators must have the ability to track the location of each miner at work in an underground mine. Since these technologies are not yet fully developed, we are working with the National Institute for Occupational Safety and Health and several manufacturers to develop new systems.

Most of the states in which we operate have inspection programs for mine safety and health. Collectively, federal and state safety and health regulations in the coal mining industry are perhaps the most comprehensive and pervasive systems for protection of employee health and safety affecting any segment of U.S. industry.

Black Lung

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each U.S. coal mine operator must pay federal black lung benefits and medical expenses to claimants who are current and former employees and last worked for the operator after July 1, 1973. Coal mine operators must also make payments 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. Historically, less than 7% of the miners currently seeking federal black lung benefits are awarded these benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

Environmental Laws

We are subject to various federal and state environmental laws. Some of these laws, discussed below, place many requirements on our coal mining operations. Federal and state regulations require regular monitoring of our mines and other facilities to ensure compliance.

Surface Mining Control and Reclamation Act

In the U.S., the Surface Mining Control and Reclamation Act of 1977 (SMCRA), which is administered by the Office of Surface Mining Reclamation and Enforcement (OSM), established mining, environmental protection and reclamation standards for all aspects of U.S. surface mining as well as many aspects of deep mining. Mine operators must obtain SMCRA permits and permit renewals for mining operations from the OSM. Where state regulatory agencies have adopted federal mining programs under SMCRA, the state becomes the regulatory authority. Except for Arizona, states in which we have active mining operations have achieved primary control of enforcement through federal authorization. In Arizona, we mine on tribal lands and are regulated by OSM because the tribes do not have SMCRA authorization.

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SMCRA permit provisions include requirements for coal prospecting; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; surface drainage control; mine drainage and mine discharge control and treatment; and re-vegetation.

The U.S. mining permit application process is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation, wildlife, assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining. Also included in the permit application are documents defining ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land and documents required of the OSM s Applicant Violator System.

Once a permit application is prepared and submitted to the regulatory agency, it goes through a completeness and technical review. Public notice of the proposed permit is given for a comment period before a permit can be issued. Some SMCRA mine permits take over a year to prepare, depending on the size and complexity of the mine and often take six months to two years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance and the public has the right to comment on and otherwise engage in the permitting process, including public hearings and through intervention in the courts.

Before a SMCRA permit is issued, a mine operator must submit a bond or other form of financial security to guarantee the performance of reclamation obligations. The Abandoned Mine Land Fund, which is part of SMCRA, requires a fee on all coal produced in the U.S. The proceeds are used to rehabilitate lands mined and left unreclaimed prior to August 3, 1977 and to pay health care benefit costs of orphan beneficiaries of the Combined Fund. The fee was $0.35 per ton of surface-mined coal and $0.15 per ton of deep-mined coal, effective through September 30, 2007. Pursuant to the Tax Relief and Health Care Act of 2006, from October 1, 2007 through September 30, 2012, the fee is $0.315 per ton of surface-mined coal and $0.135 per ton of underground mined coal. From October 1, 2012 through September 30, 2021, the fee will be reduced to $0.28 per ton of surface-mined coal and $0.12 per ton of underground mined coal.

SMCRA stipulates compliance with many other major environmental programs. These programs include the Clean Air Act; Clean Water Act; Resource Conservation and Recovery Act (RCRA); and Comprehensive Environmental Response, Compensation, and Liability Acts (CERCLA, commonly known as Superfund). Besides OSM, other federal regulatory agencies are involved in monitoring or permitting specific aspects of mining operations. The U.S. Environmental Protection Agency (EPA) is the lead agency for states or tribes with no authorized programs under the Clean Water Act, RCRA and CERCLA. The U.S. Army Corps of Engineers regulates activities affecting navigable waters and the U.S. Bureau of Alcohol, Tobacco and Firearms regulates the use of explosive blasting.

We do not believe there are any matters that pose a material risk to maintaining our existing mining permits or materially hinder our ability to acquire future mining permits. It is our policy to comply in all material respects with the requirements of the SMCRA and the state and tribal laws and regulations governing mine reclamation.

Clean Air Act

The Clean Air Act and the corresponding state laws that regulate the emissions of materials into the air affect U.S. coal mining operations both directly and indirectly. Direct impacts on coal mining and processing operations may occur through the Clean Air Act permitting requirements and/or emission control requirements relating to particulate matter. The Clean Air Act indirectly, but more significantly, affects the coal industry by extensively regulating the air emissions of sulfur dioxide, nitrogen oxides, mercury and other substances emitted by coal-based electricity generating plants.

The EPA promulgated the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) in March 2005. CAIR requires reduction of sulfur dioxide and nitrogen oxide emissions from electricity generating plants in 28 states and the District of Columbia. Substantial reductions in such emissions were already made beginning in the 1990 s under requirements of Title IV of the Clean Air Act. Once fully implemented over two rounds in 2009-2010 and 2015, CAIR is projected to reduce sulfur dioxide from power plants by approximately 73% and nitrogen oxide emissions by approximately 61% from 2003 levels.

In July and December 2008, in a case brought by the State of North Carolina and others against the EPA, the U.S. Court of Appeals for the District of Columbia rendered decisions remanding, but not vacating, CAIR (i.e., the rule as promulgated remains in effect until EPA acts on the remand). If the decision stands, the EPA will have to revisit its requirements regarding sulfur dioxide and nitrogen oxide emissions.

CAMR sought to permanently cap and reduce nationwide mercury emissions from coal-fired power plants. When fully implemented in 2018, the rule as promulgated would have reduced mercury emissions by nearly 70% according to the EPA. CAMR contained standards of performance limiting mercury emissions from new and existing power plants and sought to create a cap-and-trade program. Some states have adopted rules that are more stringent than the federal program and other states are considering such rules. In February 2008, in a case brought by the State of New Jersey and others against the EPA, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) rendered a decision effectively vacating CAMR. Although the EPA appealed the decision to the U.S. Supreme Court in October 2008, on February 6, 2009, the EPA withdrew its petition to appeal the D.C. Circuit s decision on CAMR. Instead, the EPA plans to issue technology-based standards under the Clean Air Act s National Emission Standards for Hazardous Air Pollutants program to regulate mercury emissions from power plants. Industry petitioners of the D.C. Circuit s CAMR decision intend to continue their appeal.

Implementation of CAIR, federal requirements regarding mercury emissions and related state rules could cause our customers to switch to other fuels to the extent it becomes economically preferable for them to do so.

In recent years Congress has considered legislation that would require reductions in emissions of sulfur dioxide, nitrogen oxide and mercury, greater and sooner than those required by CAIR and CAMR. No such legislation has passed either house of Congress. If enacted into law, such legislation could impact the amount of coal supplied to electricity generating customers if they decide to switch to other sources of fuel whose use would result in lower emissions of sulfur dioxide, nitrogen oxide and mercury.

In September 2006, the EPA promulgated new National Ambient Air Quality Standards revising and updating the particulate matter standards issued in July 1997. The new regulations made the 24-hour standard for very fine particulate matter (PM2.5) more stringent but left the annual PM2.5 standard unchanged. They also left the 24-hour standard for PM10 (particulate matter equal to 10 microns or more) unchanged and terminated the annual PM10 standard. The change to the 24-hour PM2.5 standard is expected to affect the use of coal for electric generation, but we believe that effect cannot be quantified at this time. Lawsuits seeking to compel the EPA to adopt more stringent standards both for PM2.5 and PM10 have been filed and are pending in court. We believe the outcome of those lawsuits cannot be reliably predicted at this time. Under the rule as currently promulgated, some states will be required to change their existing implementation plans to attain and maintain compliance with the new air quality standards. Our mining operations and electricity generating customers are likely to be directly affected when the revisions to the air quality standards are implemented by the states. Such implementation could also restrict our ability to develop new mines or require us to modify our existing operations.

The Justice Department, on behalf of the EPA, has filed a number of lawsuits since November 1999, alleging that a number of electricity generators violated the new source review provisions of the Clean Air Act Amendments (NSR) at power plants in the midwestern and southern U.S. Some electricity generators announced settlements with the

Justice Department requiring the installation of additional control equipment on selected generating units. If the remaining electricity generators are found to be in violation, they could be subject to civil penalties and could be required to install the required control equipment or cease operations. In April 2007, the U.S. Supreme Court ruled, in Environmental Defense Fund v. Duke Energy Corp., against a

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generator in an enforcement proceeding, reversing the decision of the appellate court. This decision could potentially expose numerous electricity generators to government or citizen actions based on failure to obtain NSR permits for changes to emissions sources and effectively increase the costs to them of continuing to use coal. Our customers are among the electricity generators subject to enforcement actions and if found not to be in compliance, our customers could be required to install additional control equipment at the affected plants or they could decide to close some or all of those plants. If our customers decide to install additional pollution control equipment at the affected plants, we believe we will have the ability to supply coal from the regions in which we operate to meet any new coal requirements.

In April 2007, the U.S. Supreme Court in Massachusetts v. EPA held that the Clean Air Act authorizes the EPA to regulate emissions of greenhouse gases from new motor vehicles, if the EPA makes the statutory finding concerning endangerment that is a prerequisite to such regulation. The Court also held that the EPA had not provided an adequate justification for its 2003 decision to deny a petition for such regulation. Although that petition related to new motor vehicles, the reasoning of the Court s decision could affect other Clean Air Act regulatory programs, including those that directly relate to coal use. In July 2008, the EPA published an advance notice of proposed rulemaking soliciting public comment on issues concerning possible regulation under the Clean Air Act of greenhouse gas emissions from a variety of categories of emission sources, including stationary sources that burn coal.

Clean Water Act

The Clean Water Act of 1972 affects U.S. coal mining operations by requiring effluent limitations and treatment standards for waste water discharge through the National Pollutant Discharge Elimination System (NPDES). Regular monitoring, reporting requirements and performance standards are requirements of NPDES permits that govern the discharge of pollutants into water. Section 404 under the Clean Water Act requires mining companies to obtain U.S. Army Corps of Engineers permits to place material in streams for the purpose of creating slurry ponds, water impoundments, refuse areas, valley fills or other mining activities.

States are empowered to develop and enforce in stream water quality standards. These standards are subject to change and must be approved by the EPA. Discharges must either meet state water quality standards or be authorized through available regulatory processes such as alternate standards or variances. In stream standards vary from state to state. Additionally, through the Clean Water Act section 401 certification program, states have approval authority over federal permits or licenses that might result in a discharge to their waters. States consider whether the activity will comply with its water quality standards and other applicable requirements in deciding whether or not to certify the activity.

Total Maximum Daily Load (TMDL) regulations established a process by which states designate stream segments as impaired (not meeting present water quality standards). Industrial dischargers, including coal mines, may be required to meet new TMDL effluent standards for these stream segments. States are also adopting anti-degradation regulations in which a state designates certain water bodies or streams as high quality/exceptional use. These regulations would restrict the diminution of water quality in these streams. Waters discharged from coal mines to high quality/exceptional use streams may be required to meet additional conditions or provide additional demonstrations and/or justification. In general, these Clean Water Act requirements could result in higher water treatment and permitting costs or permit delays, which could adversely affect our coal production costs or efforts.

Resource Conservation and Recovery Act

RCRA, which was enacted in 1976, affects U.S. coal mining operations by establishing cradle to grave requirements for the treatment, storage and disposal of hazardous wastes. Typically, the only hazardous wastes generated at a mine site are those from products used in vehicles and for machinery maintenance. Coal mine wastes, such as overburden and coal cleaning wastes, are not considered hazardous wastes under RCRA.

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 a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion materials generated at electric utility and independent power producing facilities. In May 2000, the EPA concluded that coal combustion materials do not warrant regulation as hazardous wastes under RCRA. The EPA has retained the hazardous waste exemption for these materials. The EPA is evaluating national non-hazardous waste guidelines for coal combustion materials placed at a mine. National guidelines for mine-fills may affect the cost of ash placement at mines.

CERCLA (Superfund)

CERCLA affects U.S. coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under CERCLA, joint and several liabilities may be imposed on waste generators, site owners or operators and others regardless of fault. Under the EPA s Toxic Release Inventory process, companies are required annually to report the use, manufacture or processing of listed toxic materials that exceed defined thresholds, including chemicals used in equipment maintenance, reclamation, water treatment and ash received for mine placement from power generation customers.

The Energy Policy Act of 2005

The Domenici-Barton Energy Policy Act of 2005 (EPACT) was signed by President Bush in August 2005. EPACT contains tax incentives and directed spending totaling an estimated $14.1 billion intended to stimulate supply-side energy growth and increased efficiency. In addition to rules affecting the leasing process of federal coal properties, EPACT programs and incentives include funding to demonstrate advanced coal technologies, including coal gasification; grants and a loan guarantee program to encourage deployment of advanced clean coal-based power generation technologies, including integrated gasification combined cycle (IGCC); a federal loan guarantee program for the cost of advanced fossil energy projects, including coal gasification; funding for energy research, development, demonstration and commercial application programs relating to coal and power systems; and tax incentives for IGCC, industrial gasification and other advanced coal-based generation projects, as well as for coal sold from Indian lands. Finally, certain sections of EPACT are potentially applicable to the area of Btu Conversion, such as the aforementioned fossil energy project loan guarantee program as well as a provision allowing taxpayers to capitalize 50% of the cost of refinery investments which increase the total throughput of qualified fuels including synthetic fuels produced from coal by at least 25%. In addition, EPACT requires the Secretary of Defense to develop a strategy to use fuel produced from coal, oil shale and tar sands (covered fuel) to assist in meeting the fuel requirements of the U.S. Department of Defense (DOD). The law authorizes the DOD to enter into multi-year contracts to procure a covered fuel to meet one or more of its fuel requirements and to carry out an assessment of potential locations for covered fuel sources.

Endangered Species Act

The U.S. Endangered Species Act and counterpart state legislation is intended to protect species whose populations allow for categorization as either endangered or threatened. With respect to obtaining mining permits, protection of endangered or threatened species may have the effect of prohibiting, limiting the extent or causing delays that may include permit conditions on the timing of, soil removal, timber harvesting, road building and other mining or agricultural activities in areas containing the associated species. Based on the species that have been identified on our properties and the current application of these laws and regulations, we do not believe that they will have a material adverse effect on our ability to mine the planned volumes of coal from our properties in accordance with current mining plans. However, there are ongoing lawsuits and petitions under these laws and regulations that, if successful, could have a material adverse effect on our ability to mine some of our properties in accordance with our current mining plans.

Regulatory Matters Australia

The Australian mining industry is regulated by Australian federal, state and local governments with respect to environmental issues such as land reclamation, water quality, air quality, dust control, noise, planning issues (such as approvals to expand existing mines or to develop new mines), and health and safety issues. The Australian federal government retains control over the level of foreign investment and export approvals. Industrial relations are regulated under both federal and state laws. Australian state governments also require coal companies to post deposits or give other security against land which is being used for mining, with those deposits being returned or security released after satisfactory reclamation is completed.

Native Title and Cultural Heritage

Since 1992, the Australian courts have recognized that native title to lands, as recognized under the laws and customs of the Aboriginal inhabitants of Australia, may have survived the process of European settlement. These developments are supported by the Federal Native Title Act (NTA) which recognizes and protects native title, and under which a national register of native title claims has been established.

Native title rights do not extend to minerals; however, native title rights can be affected by the mining process unless those rights have previously been extinguished. Native title rights can be extinguished either by a valid act of government (as set out in the NTA) or by the loss of connection between the land and the group of Aboriginal peoples concerned.

The NTA provides that where native title rights still exist and the mining project will affect those native title rights, it will be necessary to consult with the relevant Aboriginal group and to come to an agreement on issues such as the preservation of sacred or important sites, the employment of members of the group by the mine operator, and the payment of compensation for the effect on native title of the mining project. In the absence of agreement with the relevant Aboriginal group, the NTA provides for arbitration.

There is also federal and state legislation to prevent damage to Aboriginal cultural heritage and archeological sites. The NTA and laws protecting Aboriginal cultural heritage and archeological sites have had no significant impact on our current operations.

Environmental

The federal system requires that approval is obtained for any activity which will have a significant impact on a matter of national environmental significance. Matters of national environmental significance include listed endangered species, nuclear actions, World Heritage areas, National Heritage areas and migratory species. An application for such an approval may require public consultation and may be approved, refused or granted subject to conditions. Otherwise, responsibility for environmental regulation in Australia is primarily vested in the states.

Each state and territory in Australia has its own environmental and planning regime for the development of mines. In addition, each state and territory also has a specific act dealing with mining in particular, regulating the granting of mining licenses and leases. The mining legislation in each state and territory operates concurrently with environmental and planning legislation. The mining legislation governs mining licenses and leases, including the restoration of land following the completion of mining activities. Apart from the grant of rights to mine (which are covered by the mining statutes), all licensing, permitting, consent and approval requirements are contained in the various state and territory environmental and planning statutes.

The particular provisions of the various state and territory environmental and planning statutes vary depending upon the jurisdiction. Despite variation in details, each state and territory has a system involving at least two major phases. First, obtaining the developmental application and, if that is granted, obtaining the detailed operational pollution control licenses, which authorize emissions up to a maximum level; and second, obtaining pollution control approvals, which authorize the installation of pollution control equipment and devices. In the first regulatory phase, an application to a regulatory authority is filed. The relevant authority will either grant a conditional consent, an unconditional consent, or deny the application based on the details of the application and on any submissions or objections lodged by members of the public. If the developmental application is granted, the detailed pollution control license may then be issued and such license may regulate emissions to the atmosphere; emissions in waters; noise impacts, including impacts from blasting; dust impacts; the generation, handling, storage and transportation of waste; and requirements for the rehabilitation and restoration of land.

Each state and territory in Australia also has either a specific statute or certain sections in environmental and planning statutes relating to the contamination of land and vesting powers in the various regulatory authorities in respect of the remediation of contaminated land. Those statutes are based on varying policies the primary difference between the statutes is that in certain states and territories, liability for remediation is placed upon the occupier of the land, regardless of the culpability of that occupier for the contamination. In other states and territories, primary liability for remediation is placed on the original polluter, whether or not the polluter still occupies the land. If the original polluter cannot itself carry out the remediation, then a number of the statutes contain provisions which enable recovery of the costs of remediation from the polluter as a debt.

Many of the environmental planning statutes across the states and territories contain third-party appeal rights in relation, particularly, to the first regulatory phase. This means that any party has a right to take proceedings for a threatened or actual breach of the statute, without first having to establish that any particular interest of that person (other than as a member of the public) stands to be affected by the threatened or actual breach.

Accordingly, in most states and territories throughout Australia, mining activities involve a number of regulatory phases. Following exploratory investigations pursuant to a mining lease, the activity proposed to be carried out must be the subject of an application for the activity or development. This phase of the regulatory process, as noted above, usually involves the preparation of extensive documents to constitute the application, addressing all of the environmental impacts of the proposed activity. It also generally involves extensive notification and consultation with other relevant statutory authorities and members of the public. Once a decision is made to allow a mine to be developed by the grant of a development consent, permit or other approval, then a formal mining lease can be obtained under the mining statute. In addition, operational licenses and approvals can then be applied for and obtained in relation to pollution control devices and emissions to the atmosphere, to waters and for noise. The obtaining of licenses and approvals, during the operational phase, generally does not involve any extensive notification or consultation with members of the public, as most of these issues are anticipated to be resolved in the first regulatory phase.

Occupational Health and Safety

The combined effect of various state and federal statutes requires an employer to ensure that persons employed in a mine are safe from injury by providing a safe working environment and systems of work; safety machinery; equipment, plant and substances; and appropriate information, instruction, training and supervision. Our incident rate in Australia improved 26% from the prior year.

In recognition of the specialized nature of mining and mining activities, specific occupational health and safety obligations have been mandated under state legislation that deals specifically with the coal mining industry. Mining employers, owners, directors and managers, persons in control of work places, mine managers, supervisors and employees are all subject to these duties.

It is mandatory for an employer to have insurance coverage with respect to the compensation of injured workers; similar coverage is in effect throughout Australia which is of a no fault nature and which provides for benefits up to a prescribed level. The specific benefits vary by jurisdiction, but generally include the payment of weekly compensation to an incapacitated employee, together with payment of medical, hospital and related expenses. The injured employee has a right to sue his or her employer for further damages if a case of negligence can be established. The federal government is currently conducting a review of health and safety legislation with a view to harmonizing requirements across the country.

National Greenhouse and Energy Reporting Act 2007 (NGER Act)

The NGER Act introduces a single national reporting system relating to greenhouse gas emissions and energy production and consumption, which will underpin a future emissions trading scheme.

The NGER Act imposes requirements for certain corporations to report greenhouse gas emissions and abatement actions, as well as energy production and consumption, beginning July 1, 2008. Both foreign and

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local corporations that meet the prescribed CO_2 and energy production of consumption limits in Australia (controlling corporations) must comply with the NGER Act.

In the first reporting year, July 1, 2008 to June 30, 2009, a controlling corporation must register in the National Greenhouse and Energy Register if its corporate group emits a carbon dioxide equivalent of 125 kilotonnes or more. This threshold is reduced progressively in the following reporting years. Once registered, a corporation must report each financial year about its greenhouse gas emissions and energy production and consumption.

Carbon Pollution Reduction Scheme

The Federal Labor Government ratified the Kyoto Protocol in December 2007. Under the treaty, Australia has a target of restricting greenhouse gas emissions to 108% of 1990 levels during the 2008-2012 commitment period. To assist in meeting Australia s target, the Federal Government has announced that it will establish a cap and trade emissions trading scheme by July 2010 named the Carbon Pollution Reduction Scheme. There are no plans for a carbon tax. At this stage, the Federal Government has released a Green Paper and a White Paper outlining a proposed scheme. Any final legislation will require approval from both houses of parliament.

Global Climate Change

Global climate change continues to attract public and scientific attention. Widely publicized scientific reports in 2007, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. In turn, increasing government attention is being paid to global climate change and to reducing greenhouse gas emissions, including coal combustion by power plants.

Legislation was introduced in the U.S. Congress in 2006, 2007 and 2008 to reduce greenhouse gas emissions in the U.S., and additional legislation is likely to be introduced in the future. Presently there are no federal mandatory greenhouse gas reduction requirements. While it is possible that Congress will adopt some form of mandatory greenhouse gas emission reduction legislation in the future, the timing and specific requirements of any such legislation are highly uncertain.

In July 2008, the EPA published an advance notice of proposed rulemaking soliciting public comment on issues concerning possible regulation under the Clean Air Act of greenhouse gas emissions from a variety of categories of emission sources, including stationary sources that burn coal. While it is possible that the EPA may adopt regulations under the Clean Air Act with respect to greenhouse gas emissions in the future, the timing and specific requirements of any such regulations are highly uncertain.

A number of states in the U.S. have taken steps to regulate greenhouse gas emissions. For example, 10 northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont) have formed the Regional Greenhouse Gas Initiative (RGGI), which is a mandatory cap-and-trade program to reduce carbon dioxide emissions from power plants. Six midwestern states (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) and one Canadian province have entered into the Midwestern Regional Greenhouse Gas Reduction Accord to establish regional greenhouse gas reduction targets and develop a multi-sector cap-and-trade system to help meet the targets. Seven western states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and two Canadian provinces have entered into the Western Climate Initiative to establish a regional greenhouse gas reduction goal and develop market-based strategies to achieve emissions reductions. In 2006, the California legislature approved legislation allowing the imposition of statewide caps on, and cuts in, carbon dioxide emissions; and Arizona s governor signed an executive order in September 2006 that calls for the state to reduce carbon dioxide emissions. Similar legislation was adopted in 2007 in Hawaii, Minnesota and New

Jersey.

In December 1997, in Kyoto, Japan, the signatories to the 1992 Framework Convention on Climate Change, which addresses emissions of greenhouse gases, established a binding set of emission targets for developed nations. The U.S. has signed the Kyoto Protocol, but it has not been ratified by the U.S. Senate. As noted previously, Australia ratified the Kyoto Protocol in December 2007 and became a full member in March 2008.

We continue to support clean coal technology development and voluntary initiatives addressing global climate change through our participation as a founding member of the FutureGen Alliance in the U.S. and the COAL21 Fund in Australia and through our participation in the Power Systems Development Facility, the PowerTree Carbon Company LLC, the Midwest Geopolitical Sequestration Consortium and the Asia-Pacific Partnership for Clean Development and Climate. In addition, we are the only non-Chinese equity partner in GreenGen, the first near-zero emissions coal-fueled power plant with carbon capture and storage which is under development in China.

We participate in the U.S. DOE s Voluntary Reporting of Greenhouse Gases Program, and regularly disclose the quantity of greenhouse gases emitted by us per ton of coal produced in the U.S. The vast majority of our greenhouse gas emissions are generated by the operation of heavy machinery to extract and transport coal at our mines. We continue to evaluate and implement improvements in technology and infrastructure such as the new overland conveyor and near pit truck dump and crusher facility at our North Antelope Rochelle Mine in Wyoming that are expected to reduce the level of greenhouse gas emissions from our operations.

Enactment of laws and passage of regulations regarding greenhouse gas emissions by the U.S. or some of its states or by other countries, or other actions to limit carbon dioxide emissions, could result in electricity generators switching from coal to other fuel sources. The potential financial impact on us of future regulation will depend primarily upon the degree to which any such regulation forces electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such regulation.

Additional Information

We file annual, quarterly and current reports, and our amendments to those reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may access and read our SEC filings free of charge through our website, at www.peabodyenergy.com, or the SEC s website, at www.sec.gov. Information on such websites does not constitute part of this document. You may also read and copy any document we file at the SEC s public reference room located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

You may also request copies of our filings, free of charge, by telephone at (314) 342-3400 or by mail at: Peabody Energy Corporation, 701 Market Street, Suite 900, St. Louis, Missouri 63101, attention: Investor Relations.

Item 1A. *Risk Factors.*

The following risk factors relate specifically to the risks associated with our continuing operations.

Risks Associated with Our Operations

The duration or severity of the current global economic downturn and disruptions in the financial markets, and their impact on us, are uncertain.

The recent global economic downturn, coupled with the global financial and credit market disruptions, have had a negative impact on us and on the coal industry generally. While we believe that the long-term prospects for coal remain bright, we are unable to predict the duration or severity of the current global economic and financial crisis. We are focused on strong cost control and productivity improvements, increased contributions from our high-margin operations, and exercising tight capital discipline. However, there can be no assurance that these actions, or any others that we may take in response to further deterioration in economic and financial conditions, will be sufficient. A protracted continuation or worsening of the global economic downturn or disruptions in the financial markets could have a material adverse effect on our business, financial condition or results of operations.

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A decline in coal prices could negatively affect our profitability.

Our profitability depends upon the prices we receive for our coal. Coal prices are dependent upon factors beyond our control, including:

- the supply of and demand for U.S. domestic and international thermal (steam) and metallurgical coal;
- the demand for electricity and steel and the strength of the global economy;
- the availability and price of alternative fuels, such as natural gas, and alternative energy sources, such as Hydroelectric power;
- domestic and foreign governmental regulations and taxes, including those establishing air emission standards for coal-fueled power plants;
- regulatory, administrative and judicial decisions, including those affecting future mining permits;
- the proximity, capacity and cost of transportation;
- technological developments, including those intended to convert coal to liquids or gas and those aimed at capturing and sequestering carbon; and
- the effects of worldwide energy conservation measures.

As of January 27, 2009, our 2009 production is largely sold out in the U.S. with 4 to 5 million tons of Australian metallurgical coal and 5 to 6 million tons of Australian thermal coal available to price. The current global financial slowdown has reduced gross domestic product expectations for U.S., China and other major world economies, which is expected to temper the growth of coal demand in the near term. As a result, we expect 2009 coal prices to be lower than 2008 levels for our unpriced 2009 Australian-based metallurgical and thermal coal. If we continue to experience a weak coal pricing environment or if we see a further deterioration in coal prices, we could experience an adverse effect on our revenues and profitability.

A decrease in our production of metallurgical coal could reduce our anticipated profitability.

In 2008, we produced 7.8 million tons of metallurgical coal for export from our Australian Mining operations and realized prices for metallurgical coal at historically high levels, which significantly increased our profitability. Although we have annual capacity to produce approximately 8 to 10 million tons of metallurgical coal from these operations, we project that our 2009 metallurgical coal production will be reduced by up to two million tons due to the decline in worldwide steel demand. To the extent that demand for metallurgical coal further deteriorates, our profitability could be adversely affected.

If a substantial number of our long-term coal supply agreements terminate, our revenues and operating profits could suffer if we are unable to find alternate buyers willing to purchase our coal on comparable terms to those in our contracts.

Most of our sales are made under coal supply agreements, which are important to the stability and profitability of our operations. The execution of a satisfactory coal supply agreement is frequently the basis on which we undertake the development of coal reserves required to be supplied under the contract, particularly in the U.S. For the year ended December 31, 2008, 90% of our worldwide sales volume was sold under long-term coal supply agreements. At

December 31, 2008, our sales backlog, including backlog subject to price reopener and/or extension provisions, was over one billion tons, representing nearly five years of current production in backlog. Contracts in backlog have remaining terms ranging from one to 17 years.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. We may adjust these contract prices based on inflation or deflation and/or changes in the factors affecting the cost of producing coal, such as taxes, fees, royalties and changes in the laws regulating the mining, production, sale or use of coal. In a limited number of contracts, failure of the parties to agree on a price under those provisions may allow either party to terminate the contract. We sometimes experience a reduction in coal prices in new long-term coal supply agreements replacing some of our expiring contracts. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer during the duration of specified events beyond the control of the affected party. Most coal supply agreements contain provisions requiring us to deliver coal meeting quality thresholds for certain characteristics such as Btu, sulfur content, ash content, grindability and ash fusion temperature. Failure to meet these specifications could result in economic penalties, including price adjustments, the rejection of deliveries or termination of the contracts. Moreover, some of these agreements permit the customer to terminate the contract if transportation costs, which our customers typically bear, increase substantially. In addition, some of these contracts allow our customers to terminate their contracts in the event of changes in regulations affecting our industry that increase the price of coal beyond specified limits.

The operating profits we realize from coal sold under supply agreements depend on a variety of factors. In addition, price adjustment and other provisions may increase our exposure to short-term coal price volatility provided by those contracts. If a substantial portion of our coal supply agreements were modified or terminated, we could be materially adversely affected to the extent that we are unable to find alternate buyers for our coal at the same level of profitability. Market prices for coal vary by mining region and country. As a result, we cannot predict the future strength of the coal market overall or by mining region and cannot assure you that we will be able to replace existing long-term coal supply agreements at the same prices or with similar profit margins when they expire.

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

For the year ended December 31, 2008, we derived 24% of our total coal revenues from sales to our five largest customers. At December 31, 2008, we had 66 coal supply agreements and trading transactions with these customers expiring at various times from 2009 to 2014. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and those customers may not continue to purchase coal from us under long-term coal supply agreements. If a number of these customers significantly reduce their purchases of coal from us, or if we are unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially. In addition, our revenue could be adversely affected by a decline in customer purchases due to lack of demand, cost of competing fuels and environmental regulations.

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. Our customer base has changed with deregulation as utilities have sold their power plants to their non-regulated affiliates or third parties. These new power plant owners or other customers may have credit ratings that are below investment grade. If deterioration of the creditworthiness of our customers occurs, our $275.0 million accounts receivable securitization program and our business could be adversely affected.

If transportation for our coal becomes unavailable or uneconomic for our customers, our ability to sell coal could suffer.

Transportation costs represent a significant portion of the total cost of coal and the cost of transportation is a critical factor in a customer s purchasing decision. Increases in transportation costs and the lack of sufficient rail and port capacity could lead to reduced coal sales. As of December 31, 2008, certain coal supply agreements permit the customer to terminate the contract if the cost of transportation increases by an amount over specified levels in any given 12-month period.

Coal producers depend upon rail, barge, trucking, overland conveyor and ocean-going vessels to deliver coal to markets. While our coal customers typically arrange and pay for transportation of coal from the mine or port to the point of use, disruption of these transportation services because of weather-related problems, infrastructure damage, strikes, lock-outs, lack of fuel or maintenance items, transportation delays or other events could temporarily impair our ability to supply coal to our customers and thus could adversely affect our results of operations. For example, two primary railroads serve the Powder River Basin mines. Due to the high volume of coal shipped from all Powder River Basin mines, the loss of access to rail capacity could create temporary congestion on the rail systems servicing that region. In Australia we currently ship coal through the ports of Dalrymple Bay, Brisbane, Newcastle and Port Kembla. In most instances, we rail coal to these ports. The Australian coal supply chains (rail and port) can be impacted by a number of factors including weather events, breakdown or underperformance of the port and rail infrastructure, congestion and balancing systems which are imposed to manage vessel queuing and demurrage. As a result, we are susceptible to increased costs or lost sales due to Australian coal chain problems.

A decrease in the availability or increase in costs of key supplies, capital equipment or commodities such as diesel fuel, steel, explosives and tires could decrease our anticipated profitability.

Our mining operations require a reliable supply of mining equipment, replacement parts, explosives, fuel, tires, steel-related products (including roof control) and lubricants. Recent consolidation of suppliers of explosives has limited the number of sources for these materials, and our current supply of explosives is concentrated with two suppliers. Further, our purchases of some items of underground mining equipment are concentrated with one principal supplier. If the cost of any of these inputs increased significantly, or if a source for these supplies or mining equipment were unavailable to meet our replacement demands, our profitability could be reduced.

An inability of trading, brokerage or freight sources to fulfill the delivery terms of their contracts with us could reduce our profitability.

In conducting our trading, brokerage and mining operations, we utilize third-party sources of coal production, including contract miners and brokerage sources, to fulfill deliveries under our coal supply agreements. In Australia, the majority of our volume comes from mines that utilize contract miners. Employee relations at mines that use contract miners is the responsibility of the contractor.

Our profitability or exposure to loss on transactions or relationships is dependent upon the reliability (including financial viability) and price of the third-party suppliers, our obligation to supply coal to customers in the event that adverse geologic mining conditions restrict deliveries from our suppliers, our willingness to participate in temporary cost increases experienced by our third-party coal suppliers, our ability to pass on temporary cost increases to our customers, the ability to substitute, when economical, third-party coal sources with internal production or coal purchased in the market, the ability of our freight sources to fulfill their delivery obligations and other factors. The recent market volatility and price increases for coal on the international and domestic markets could result in non-performance by third-party suppliers under existing contracts with us, in order to take advantage of the higher prices in the current market. Such non-performance could have an adverse impact on our ability to fulfill deliveries under our coal supply agreements.

If the coal industry experiences overcapacity in the future, our profitability could be impaired.

Coal prices in most regions of the U.S. and globally were approaching record highs in the first half of 2008, which encouraged producers to increase planned capacity. Many of these planned capacity increases and existing production plans have been delayed or reduced due to the global economic downturn and coal price reductions in the second half of 2008. To the extent that demand drops below supply, our profitability could be materially adversely affected.

Risks inherent to mining could increase the cost of operating our business.

Our mining operations are subject to conditions that can impact the safety of our workforce, or delay coal deliveries or increase the cost of mining at particular mines for varying lengths of time. These conditions include fires and explosions from methane gas or coal dust; accidental minewater discharges; weather, flooding and natural disasters; unexpected maintenance problems; key equipment failures; variations in coal seam thickness; variations in the amount of rock and soil overlying the coal deposit; variations in rock and other natural materials; and variations in geologic conditions. We maintain insurance policies that provide limited coverage for some of these risks, although there can be no assurance that these risks would be fully covered by our insurance policies. Despite our efforts, significant mine accidents could occur and have a substantial impact on our financial condition and results of operations.

Our ability to operate our company effectively could be impaired if we lose key personnel or fail to attract qualified personnel.

We manage our business with a number of key personnel, the loss of a number of whom could have a material adverse effect on us. In addition, as our business develops and expands, we believe that our future success will depend greatly on our continued ability to attract and retain highly skilled and qualified personnel. We cannot assure that key personnel will continue to be employed by us or that we will be able to attract and retain qualified personnel in the future. Failure to retain or attract key personnel could have a material adverse effect on us.

We could be negatively affected if we fail to maintain satisfactory labor relations.

As of December 31, 2008, we had approximately 7,200 employees. In the U.S., approximately 15% of our U.S. subsidiaries hourly employees are represented by unions and they generated approximately 6% of our U.S. production during the year ended December 31, 2008. In Australia, the majority of workers are members of trade unions, including those employed through contract mining relationships. Relations with our employees and, where applicable, organized labor are important to our success.

Due to the higher labor costs and the increased risk of strikes and other work-related stoppages that may be associated with union operations in the coal industry, our competitors who operate without union labor may have a competitive advantage in areas where they compete with our unionized operations. If some or all of our current non-union operations were to become unionized, we could incur an increased risk of work stoppages, reduced productivity and higher labor costs.

Our operations could be adversely affected if we fail to appropriately secure our obligations.

U.S. federal and state laws and Australian laws require us to secure certain of our obligations to reclaim lands used for mining, to pay federal and state workers compensation, to secure coal lease obligations and to satisfy other miscellaneous obligations. The primary methods for us to meet those obligations are to post a corporate guarantee (i.e. self bond), provide a third-party surety bond or provide a letter of credit. As of December 31, 2008, we had $773.4 million of self bonding in place for our reclamation obligations. As of December 31, 2008, we also had outstanding surety bonds with third parties and letters of credit of $1,128.6 million, of which $740.7 million was for post-mining reclamation, $74.2 million related to workers compensation obligations, $99.2 million was for coal lease obligations and $214.5 million was for other obligations, including collateral for surety companies and bank guarantees, road maintenance and performance guarantees. As of December 31, 2008, the amount of letters of credit securing Patriot obligations was $7.0 million related to Patriot s workers compensation obligations. Surety bonds are typically renewable on a yearly basis. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. Letters of credit are subject to our successful renewal of our bank Revolving Credit Facility, which expires in 2011. Our failure to maintain, or inability to acquire, surety bonds or letters of credit or to provide a suitable alternative would have a material adverse effect on us. That failure could result from a variety of factors including the following:

- lack of availability, higher expense or unfavorable market terms of new surety bonds;

- restrictions on the availability of collateral for current and future third-party surety bond issuers under the terms of our indentures or Senior Unsecured Credit Facility;

the exercise by third-party surety bond issuers of their right to refuse to renew the surety; and

inability to renew our credit facility.

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Our ability to self bond reduces our costs of providing financial assurances. To the extent we are unable to maintain our current level of self bonding, due to legislative or regulatory changes or changes in our financial condition, our costs would increase.

Our mining operations are extensively regulated, which imposes significant costs on us, and future regulations and developments could increase those costs or limit our ability to produce coal.

Federal, state and local authorities regulate the coal mining industry with respect to matters such as employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. We are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be costly and time-consuming and may delay commencement or continuation of exploration or production. The possibility exists that new legislation and/or regulations and orders related to the environment or employee health and safety may be adopted and may materially adversely affect our mining operations, our cost structure and/or our customers ability to use coal. New legislation or administrative regulations (or judicial interpretations of existing laws and regulations), including proposals related to the protection of the environment or the reduction of greenhouse gas emissions that would further regulate and tax the coal industry, may also require us or our customers to change operations significantly or incur increased costs. Some of our coal supply agreements contain provisions that allow a purchaser to terminate its contract if legislation is passed that either restricts the use or type of coal permissible at the purchaser s plant or results in specified increases in the cost of coal or its use. These factors and legislation, if enacted, could have a material adverse effect on our financial condition and results of operations.

A number of laws, including in the U.S. the CERCLA, impose liability relating to contamination by hazardous substances. Such liability may involve the costs of investigating or remediating contamination and damages to natural resources, as well as claims seeking to recover for property damage or personal injury caused by hazardous substances. Such liability may arise from conditions at formerly, as well as currently, owned or operated properties, and at properties to which hazardous substances have been sent for treatment, disposal, or other handling. Liability under CERCLA and similar state statutes is without regard to fault, and typically is joint and several, meaning that a person may be held responsible for more than its share, or even all of, the liability involved. Our mining operations involve some use of hazardous materials. In addition, we have accrued for liability arising out of contamination associated with Gold Fields Mining, LLC (Gold Fields), a dormant, non-coal-producing subsidiary of ours that was previously managed and owned by Hanson PLC, or with Gold Fields former affiliates. A predecessor owner of ours, Hanson PLC, transferred ownership of Gold Fields to us in the February 1997 spin-off of its energy business. Gold Fields is currently a defendant in several lawsuits and has received notices of several other potential claims arising out of lead contamination from mining and milling operations it conducted in northeastern Oklahoma. Gold Fields is also involved in investigating or remediating a number of other contaminated sites. Although we have accrued for many of these liabilities known to us, the amounts of other potential losses cannot be estimated. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than our accrual. Although we believe many of these liabilities are likely to be resolved without a material adverse effect on us, future developments, such as new information concerning areas known to be or suspected of being contaminated for which we may be responsible, the discovery of new contamination for which we may be responsible, or the inability to share costs with other parties that may be responsible for the contamination, could have a material adverse effect on our financial condition or results of operations.

Our future success depends upon our ability to continue acquiring and developing coal reserves that are economically recoverable.

Our recoverable reserves decline as we produce coal. We have not yet applied for the permits required or developed the mines necessary to use all of our reserves. Furthermore, we may not be able to mine all of our reserves as profitably as we do at our current operations. Our future success depends upon our conducting successful exploration and development activities or acquiring properties containing economically recoverable reserves. Our current strategy includes increasing our reserves through acquisitions of government and other leases and producing properties and continuing to use our existing properties. The federal government also leases natural gas and coalbed methane reserves in the West, including in the Powder River Basin. Some of these natural gas and coalbed methane reserves are located on, or adjacent to, some of our Powder River Basin reserves, potentially creating conflicting interests between us and lessees of those interests. Other lessees rights relating to these mineral interests could prevent, delay or increase the cost of developing our coal reserves. These lessees may also seek damages from us based on claims that our coal mining operations impair their interests. Additionally, the federal government limits the amount of federal land that may be leased by any company to 150,000 acres nationwide. As of December 31, 2008, we leased a total of 64,154 acres from the federal government. The limit could restrict our ability to lease additional federal lands.

Our planned mine development projects and acquisition activities may not result in significant additional reserves, and we may not have continuing success developing additional mines. Most of our mining operations are conducted on properties owned or leased by us. Because we do not thoroughly verify title to most of our leased properties and mineral rights until we obtain a permit to mine the property, our right to mine some of our reserves may be materially adversely affected if defects in title or boundaries exist. In addition, in order to develop our reserves, we must receive various governmental permits. We cannot predict whether we will continue to receive the permits necessary for us to operate profitably in the future. We may not be able to negotiate new leases from the government or from private parties, obtain mining contracts for properties containing additional reserves or maintain our leasehold interest in properties on which mining operations are not commenced during the term of the lease. From time to time, we have experienced litigation with lessors of our coal properties and with royalty holders.

Growth in our global operations increases our risks unique to international mining and trading operations.

We currently have international mining operations in Australia and Venezuela. We have a business development, sales and marketing office in Beijing, China and an international trading group in our Trading and Brokerage operations. In addition, we are actively pursuing long-term operating, trading and joint-venture opportunities in China, Mongolia and Mozambique. The international expansion of our operations increases our exposure to country and currency risks. Some of our international activities include expansion into developing countries where business practices and counterparty reputations may not be as well developed as in our U.S. or Australian operations. We are also challenged by political risks, including expropriation and the inability to repatriate earnings on our investment. In particular, the Venezuelan government has suggested its desire to increase government ownership in Venezuelan energy assets and natural resources. Actions to nationalize Venezuelan coal properties could be detrimental to our investment in the Paso Diablo Mine. During 2008, the Paso Diablo Mine contributed $5.7 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA (see Item 7) and paid a dividend of $19.9 million. At December 31, 2008, our investment in Paso Diablo was $54.2 million, recorded in Investments and other assets on the consolidated balance sheet.

Risks Associated with Our Indebtedness

We could be adversely affected by the failure of financial institutions to fulfill their commitments under our Senior Unsecured Credit Facility.

As of December 31, 2008, we had $1.5 billion of available borrowing capacity under our Senior Unsecured Credit Facility, net of outstanding letters of credit. This committed facility, which matures on

September 15, 2011, is provided by a syndicate of financial institutions, with each institution agreeing severally (and not jointly) to make revolving credit loans to us in accordance with the terms of the facility. If one or more of the financial institutions providing the Senior Unsecured Credit Facility were to default on its obligation to fund its commitment, the portion of the facility provided by such defaulting financial institution would not be available to us.

Our financial performance could be adversely affected by our debt.

Our financial performance could be affected by our indebtedness. As of December 31, 2008, our total indebtedness was $3.2 billion, and we had $1.5 billion of available borrowing capacity under our Revolving Credit Facility. The indentures governing our Convertible Junior Subordinated Debentures (the Debentures) and 7.375% and 7.875% Senior Notes do not limit the amount of indebtedness that we may issue, and the indentures governing our 6.875% and 5.875% Senior Notes permit the incurrence of additional indebtedness.

The degree to which we are leveraged could have important consequences, including, but not limited to:

- making it more difficult for us to pay interest and satisfy our debt obligations;
- increasing our vulnerability to general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to the payment of principal, and interest on, our indebtedness, thereby reducing the availability of our cash flow to fund working capital, capital expenditures, acquisitions, research and development or other general corporate uses;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions, research and development or other general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and in the coal industry; and
- placing us at a competitive disadvantage compared to less leveraged competitors.

In addition, our debt agreements subject us to financial and other restrictive covenants. Failure by us to comply with these covenants could result in an event of default that, if not cured or waived, could have a material adverse effect on us.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to sell assets, seek additional capital or seek to restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. The Senior Unsecured Credit Facility and indentures governing certain of our notes restrict our ability to sell assets and use the proceeds from the sales. We may not be able to consummate those sales or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

The covenants in our Senior Unsecured Credit Facility and the indentures governing our Senior Notes and Debentures impose restrictions that may limit our operating and financial flexibility.

Our Senior Unsecured Credit Facility, the indentures governing our 6.875% and 5.875% Senior Notes and Debentures and the instruments governing our other indebtedness contain certain restrictions and covenants which restrict our ability to incur liens and debt or provide guarantees in respect of obligations of any other person. Under our Senior

Unsecured Credit Facility, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined. The financial covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on our assets. These covenants and restrictions are reasonable and customary and have not impacted our business in the past.

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Operating results below current levels or other adverse factors, including a significant increase in interest rates, could result in our inability to comply with the financial covenants contained in our Senior Unsecured Credit Facility. If we violate these covenants and are unable to obtain waivers from our lenders, our debt under these agreements would be in default and could be accelerated by our lenders. If our indebtedness is accelerated, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if we are able to obtain new financing, it may not be on commercially reasonable terms, on terms that are acceptable to us or at all. If our debt is in default for any reason, our business, financial condition and results of operations could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to holders of our other debt or equity securities and may make it more difficult for us to successfully execute our business strategy and compete against companies who are not subject to such restrictions.

The conversion of our Debentures may result in the dilution of the ownership interests of our existing stockholders.

If the conditions permitting the conversion of our Debentures are met and holders of the Debentures exercise their conversion rights, any conversion value in excess of the principal amount will be delivered in shares of our common stock. If any common stock is issued in connection with a conversion of our Debentures, our existing stockholders will experience dilution in the voting power of their common stock and earnings per share could be negatively impacted.

Provisions of our Debentures could discourage an acquisition of us by a third-party.

Certain provisions of our Debentures could make it more difficult or more expensive for a third-party to acquire us. Upon the occurrence of certain transactions constituting a change of control as defined in the indenture relating to our Debentures, holders of our Debentures will have the right, at their option, to convert their Debentures and thereby require us to pay the principal amount of such Debentures in cash.

Other Business Risks

Under certain circumstances, we could be responsible for certain federal and state black lung occupational disease liabilities assumed by Patriot in connection with its spin-off from us.

Patriot is responsible for certain federal and state black lung occupational disease liabilities up to $150 million, as well as related credit capacity in support of these liabilities. Should Patriot not fund these obligations as they become due, we could be responsible for such costs when incurred.

Our expenditures for postretirement benefit and pension obligations could be materially higher than we have predicted if our underlying assumptions prove to be incorrect.

We provide postretirement health and life insurance benefits to eligible union and non-union employees. We calculated the total accumulated postretirement benefit obligation under SFAS No. 106, which was a liability of $833.4 million as of December 31, 2008, $67.3 million of which was a current liability. Net pension liabilities were $216.0 million as of December 31, 2008, $1.6 million of which was a current liability.

These liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities.

We have made assumptions related to future trends for medical care costs in the estimates of retiree health care and work-related injuries and illnesses obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. In addition, we make assumptions related to future compensation increases and rates of return on plan assets in the estimates of pension obligations.

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If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes or changes in medical benefits provided by the government could increase our obligation to satisfy these or additional obligations.

The decline in the stock market and real estate values which occurred in 2008 led to a decline in the value of our pension plan assets as of December 31, 2008. We have experienced additional asset value declines in early 2009. The decline in asset values will, without a significant recovery of asset values in 2009, increase the required contributions to our pension plans in future periods.

Concerns about the environmental impacts of coal combustion, including perceived impacts on global climate change, are resulting in increased regulation of coal combustion in many jurisdictions, and interest in further regulation, which could significantly affect demand for our products.

Global climate change continues to attract public and scientific attention. Widely publicized scientific reports in 2007, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, have also engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. In turn, increasing government attention is being paid to global climate change and to reducing greenhouse gas emissions, including coal combustion by power plants.

Enactment of laws and passage of regulations regarding greenhouse gas emissions by the U.S. or some of its states, or other actions to limit carbon dioxide emissions, could result in electricity generators switching from coal to other fuel sources. The potential financial impact on us of future regulation will depend primarily upon the degree to which any such regulation forces electricity generators to diminish their reliance on coal as a fuel source. That, in turn, will depend on a number of factors, including the specific requirements imposed by any such regulation.

Further developments in connection with legislation, regulations or other limits on greenhouse gas emissions and other environmental impacts from coal combustion, both in the U.S. and in other countries where we sell coal, could have a material adverse effect on our results of operations, cash flows and financial condition.

As we continue to pursue Btu Conversion activities, we face challenges and risks that differ from those in our mining business.

We continue to pursue opportunities to participate in technologies to economically convert a portion of our coal resources to natural gas and liquids such as diesel fuel, gasoline and jet fuel (Btu Conversion). As we move forward with these projects, we are exposed to risks related to the performance of our partners, securing required financing, obtaining necessary permits, meeting stringent regulatory laws, maintaining strong supplier relationships and managing (along with our partners) large projects, including managing through long lead times for ordering and obtaining capital equipment. Our work in new or recently commercialized technologies could expose us to unanticipated risks, evolving legislation and uncertainty regarding the extent of future government support and funding.

Our certificate of incorporation and by-laws include provisions that may discourage a takeover attempt.

Provisions contained in our certificate of incorporation and by-laws and Delaware law could make it more difficult for a third-party to acquire us, even if doing so might be beneficial to our stockholders. Provisions of our by-laws and certificate of incorporation impose various procedural and other requirements that could make it more difficult for stockholders to effect certain corporate actions. For example, a change in control of our Company may be delayed or deterred as a result of the stockholders rights plan adopted by our Board of Directors. These provisions could limit the price that certain investors might be willing to pay in the future for shares of our common stock and may have the effect of delaying or preventing a change in control.

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Diversity in interpretation and application of accounting literature in the mining industry may impact our reported financial results.

The mining industry has limited industry-specific accounting literature and, as a result, we understand diversity in practice exists in the interpretation and application of accounting literature to mining specific issues. For example, some companies capitalize drilling and related costs incurred to delineate and classify mineral resources as proven and probable reserves, and other companies expense such costs. In addition, some industry participants expense pre-production stripping costs associated with developing new pits at existing surface mining operations, while other companies capitalize pre-production stripping costs for new pit development at existing operations. The materiality of such expenditures can vary greatly relative to a given company s respective financial position and results of operations. As diversity in mining industry accounting is addressed, we may need to restate our reported results if the resulting interpretations differ from our current accounting practices.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Coal Reserves

We had an estimated 9.2 billion tons of proven and probable coal reserves as of December 31, 2008. An estimated 8.1 billion tons of our proven and probable coal reserves are in the U.S. and 1.1 billion tons are in Australia. 45% of our reserves, or 4.2 billion tons, are compliance coal and 55% are non-compliance coal (assuming application of the U.S. industry standard definition of compliance coal to all of our reserves). We own approximately 38% of these reserves and lease property containing the remaining 62%. Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emission allowance credits or blending higher sulfur coal with lower sulfur coal.

Below is a table summarizing the locations and reserves of our major operating regions.

		Proven and Probable Reserves as of December 31, 2008[1]		
Operating Regions	**Locations**	**Owned Tons**	**Leased Tons (Tons in millions)**	**Total Tons**
Midwest	Illinois, Indiana and Kentucky	2,678	974	3,652
Powder River Basin	Wyoming and Montana	67	3,132	3,199
Southwest	Arizona and New Mexico	703	308	1,011
Colorado	Colorado	30	173	203
Total United States		3,478	4,587	8,065
Australia	New South Wales		505	505

Australia	Queensland		630	630
Total Australia			1,135	1,135
Total Proven and Probable Coal Reserves		3,478	5,722	9,200

(1) Reserves have been adjusted to take into account estimated losses involved in producing a saleable product.

Reserves are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) 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 close and the geographic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven (measured) reserves, but the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven (measured) reserves, is high enough to assume continuity between points of observation.

Our estimates of proven and probable coal reserves are established within these guidelines. Proven reserves require the coal to lie within one-quarter mile of a valid point of measure or point of observation, such as exploratory drill holes or previously mined areas. Estimates of probable reserves may lie more than one-quarter mile, but less than three-quarters of a mile, from a point of thickness measurement. Estimates within the proven category have the highest degree of assurance, while estimates within the probable category have only a moderate degree of geologic assurance. Further exploration is necessary to place probable reserves into the proven reserve category. Our active properties generally have a much higher degree of reliability because of increased drilling density. Active surface reserves generally have points of observation as close as 330 feet to 660 feet.

Our reserve estimates are prepared by our staff of geologists, whose experience ranges from 10 to over 32 years. We also have a chief geologist of reserve reporting whose primary responsibility is to track changes in reserve estimates, supervise our other geologists and coordinate periodic third-party reviews of our reserve estimates by qualified mining consultants.

Our reserve estimates are predicated on information obtained from our ongoing drilling program, which totals nearly 500,000 individual drill holes. We compile data from individual drill holes in a computerized drill-hole database from which the depth, thickness and, where core drilling is used, the quality of the coal is determined. The density of the drill pattern determines whether the reserves will be classified as proven or probable. The reserve estimates are then input into our computerized land management system, which overlays the geological data with data on ownership or control of the mineral and surface interests to determine the extent of our reserves in a given area. The land management system contains reserve information, including the quantity and quality (where available) of reserves as well as production rates, surface ownership, lease payments and other information relating to our coal reserves and land holdings. We periodically update our reserve estimates to reflect production of coal from the reserves and new drilling or other data received. Accordingly, reserve estimates will change from time to time to reflect mining activities, analysis of new engineering and geological data, changes in reserve holdings, modification of mining methods and other factors.

Our estimate of the economic recoverability of our reserves is based upon a comparison of unassigned reserves to assigned reserves currently in production in the same geologic setting to determine an estimated mining cost. These estimated mining costs are compared to expected market prices for the quality of coal expected to be mined and taking into consideration typical contractual sales agreements for the region and product. Where possible, we also review production by competitors in similar mining areas. Only reserves expected to be mined economically are included in our reserve estimates. Finally, our reserve estimates include reductions for recoverability factors to estimate a saleable product.

We periodically engage independent mining and geological consultants and consider their input regarding the procedures used by us to prepare our internal estimates of coal reserves, selected property reserve estimates and tabulation of reserve groups according to standard classifications of reliability.

With respect to the accuracy of our reserve estimates, our experience is that recovered reserves are within plus or minus 10% of our proven and probable estimates, on average, and our probable estimates are generally within the same statistical degree of accuracy when the necessary drilling is completed to move reserves from the probable to the proven classification.

We have numerous federal coal leases that are administered by the U.S. Department of the Interior under the Federal Coal Leasing Amendments Act of 1976. These leases cover our principal reserves in Wyoming and other reserves in Montana and Colorado. Each of these leases continues indefinitely, provided there is diligent development of the property and continued operation of the related mine or mines. The Bureau of Land Management has asserted the right to adjust the terms and conditions of these leases, including rent and royalties, after the first 20 years of their term and at 10-year intervals thereafter. Annual rents on surface land under our federal coal leases are now set at $3.00 per acre. Production royalties on federal leases are set by statute at 12.5% of the gross proceeds of coal mined and sold for surface-mined coal and 8% for underground-mined coal. The federal government limits by statute the amount of federal land that may be leased by any company and its affiliates at any time to 75,000 acres in any one state and 150,000 acres nationwide. As of December 31, 2008, we leased 11,478 acres of federal land in Colorado, 11,254 acres in Montana and 41,422 acres in Wyoming, for a total of 64,154 nationwide.

Similar provisions govern three coal leases with the Navajo and Hopi Indian tribes. These leases cover coal contained in 65,000 acres of land in northern Arizona lying within the boundaries of the Navajo Nation and Hopi Indian reservations. We also lease coal-mining properties from various state governments.

Private U.S. coal leases normally have terms of between 10 and 20 years and usually give us the right to renew the lease for a stated period or to maintain the lease in force until the exhaustion of mineable and merchantable coal contained on the relevant site. These private U.S. leases provide for royalties to be paid to the lessor either as a fixed amount per ton or as a percentage of the sales price. Many U.S. leases also require payment of a lease bonus or minimum royalty, payable either at the time of execution of the lease or in periodic installments.

The terms of our private U.S. leases are normally extended by active production at or near the end of the lease term. U.S. leases containing undeveloped reserves may expire or these leases may be renewed periodically. With a portfolio of approximately 9.2 billion tons, we believe that we have sufficient reserves to replace capacity from depleting mines for the foreseeable future and that our significant reserve holdings is one of our strengths. We believe that the current level of production at our major mines is sustainable for the foreseeable future.

Mining and exploration in Australia is generally carried on under leases or licenses granted by state governments. Mining leases are typically for an initial term of up to 21 years (but which may be renewed) and contain conditions relating to such matters as minimum annual expenditures, restoration and rehabilitation. Royalties are paid to the state government as a percentage of sale prices. Generally landowners do not own the mineral rights or have the ability to grant rights to mine those minerals. These rights are retained by state governments. Compensation is payable to landowners for loss of access to the land, and the amount of compensation can be determined by agreement or arbitration. Surface rights are typically acquired directly from landowners and, in the absence of agreement, there is an arbitration provision in the mining law.

Consistent with industry practice, we conduct only limited investigation of title to our coal properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased properties are not completely verified until we prepare to mine those reserves.

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The following chart provides a summary, by mining complex, of production for the years ended December 31, 2008 and 2007 and 2006, tonnage of coal reserves that is assigned to our operating mines, our property interest in those reserves and other characteristics of the facilities.

PRODUCTION AND ASSIGNED RESERVES[1]
(Tons in Millions)

	Production				Sulfur Content[2]					As of Decembe	
Mining Complex	Year Ended Dec. 31, 2008	Year Ended Dec. 31, 2007	Year Ended Dec. 31, 2006	Type of Coal	<1.2 lbs. sulfur dioxide per Million Btu	>1.2 to 2.5 lbs. sulfur dioxide per Million Btu	>2.5 lbs. sulfur dioxide per Million Btu	As Received Btu per pound[3]	Assigned Proven and Probable Reserves	Owned	Lease
	1.9	2.1	2.2	Steam	22	1	34	11,300	57	2	5
	1.9	1.6	1.6	Steam		1	23	11,100	24	23	
	1.9	2.2	2.0	Steam			3	11,000	3		
d	1.5	0.9	1.1	Steam			39	11,400	39	7	3
	3.4	3.5	3.8	Steam		2	22	10,900	24	22	
	3.5	3.4	3.5	Steam				NA			
	2.2	2.5	2.4	Steam			4	11,200	4	4	
	2.2	2.5	2.5	Steam			13	11,100	13	8	
	1.6	1.7	1.5	Steam		1	7	11,500	8		
	2.9	2.9	2.4	Steam			37	12,200	37	23	1
	3.6	3.6	3.6	Steam			37	12,100	37	29	
	3.2	2.7	2.6	Steam			16	11,000	16	16	
	29.8	29.6	29.2		22	5	235		262	134	12
lle	97.6	91.5	88.6	Steam	980			8,800	980		98
	31.2	31.2	32.8	Steam	715	127	25	8,100	867		86
	18.4	17.2	17.0	Steam	317	72	9	8,300	398		39
	147.2	139.9	138.4		2,012	199	34		2,245		2,24
	8.0	8.0	8.2	Steam	177	83	4	11,000	264		26
	3.3	5.3	5.5	Steam	19	121	13	9,400	153	125	2
	8.0	8.3	8.6	Steam	58			10,700	58	10	4
	3.3			Steam	36	90	77	9,300	203	186	1
	22.6	21.6	22.3		290	294	94		678	321	35

lefield	2.8	2.8	2.2	Met.	42			12,900	42		4
	1.5	1.5	0.4	Met.	50			12,600	50		5
	2.6	2.4	2.0	Steam	349			10,800	349		34
4)	0.5	0.6	0.2	Steam	17			10,600	17		1
	5.4	4.4	1.2	Steam	242			12,200	242		24
	2.6	3.1	4.3	Steam/Met.	35			12,700	35		3
	7.5	5.1	0.3	Steam		196		11,200	196		19
	1.2	1.3	0.1	Met.	22			12,600	22		2
	24.1	21.2	10.7		757	196			953		95
ations	223.7	212.3	200.6		3,081	694	363		4,138	455	3,68
ns	1.5	18.8	25.2								
	225.2	231.1	225.8		3,081	694	363		4,138	455	3,68

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The following chart provides a summary of the amount of our proven and probable coal reserves in each U.S. state and Australia state, the predominant type of coal mined in the applicable location, our property interest in the reserves and other characteristics of the facilities.

ASSIGNED AND UNASSIGNED PROVEN AND PROBABLE COAL RESERVES AS OF DECEMBER 31, 2008

(Tons in Millions)

Total Tons		Proven and Probable			Type of	Sulfur Content[2]			As	Reserve Control		
						<1.2 lbs. sulfur dioxide per Million Btu	>1.2 to 2.5 lbs. sulfur dioxide per Million Btu	>2.5 lbs. sulfur dioxide per Million Btu	Received Btu per			
ssigned	Unassigned	Reserves	Proven	Probable	Coal				pound[3]	Owned	Leased	S
90	2,169	2,259	1,141	1,118	Steam		11	2,248	11,000	1,847	412	
172	604	776	507	269	Steam	23	34	719	11,200	436	340	
	617	617	302	315	Steam		1	616	11,400	395	222	
262	3,390	3,652	1,950	1,702		23	46	3,583		2,678	974	
	162	162	158	4	Steam	9	121	32	8,500	67	95	
2,245	792	3,037	2,975	62	Steam	2,781	199	57	8,500		3,037	
2,245	954	3,199	3,133	66		2,790	320	89		67	3,132	
264		264	264		Steam	177	83	4	11,100		264	
58	145	203	146	57	Steam	146		57	11,000	30	173	
356	391	747	679	68	Steam	98	373	276	9,300	703	44	
678	536	1,214	1,089	125		421	456	337		733	481	
505		505	361	144	Steam/Met.	315	190		11,800		505	
448	182	630	97	533	Steam/Met.	628	2		11,200		630	
953	182	1,135	458	677		943	192				1,135	
4,138	5,062	9,200	6,630	2,570		4,177	1,014	4,009		3,478	5,722	

(1) Assigned reserves represent recoverable coal reserves that are controlled and accessible at active operations as of December 31, 2008. Unassigned reserves represent coal at currently non-producing locations that would require new mine development, mining equipment or plant facilities before operations could begin on the property.

(2) Compliance coal is defined by Phase II of the Clean Air Act as coal having sulfur dioxide content of 1.2 pounds or less per million Btu. Non-compliance coal is defined as coal having sulfur dioxide content in excess of this standard. Electricity generators are able to use coal that exceeds these specifications by using emissions reduction technology, using emissions allowance credits or blending higher sulfur coal with lower sulfur coal.

(3) As-received Btu per pound includes the weight of moisture in the coal on an as sold basis. The range of variability of the moisture content in coal across a given region may affect the actual shipped Btu content of current production from assigned reserves.

(4) Proven and probable coal reserves for these joint ventures reflect our proportional ownership as indicated parenthetically.

Item 3. *Legal Proceedings.*

From time to time, we or our subsidiaries are involved in legal proceedings arising in the ordinary course of business or related to indemnities or historical operations. We believe we have recorded adequate reserves for these liabilities and that there is no individual case pending that is likely to have a material adverse effect on our financial condition, results of operations or cash flows. We discuss our significant legal proceedings below.

Litigation Relating to Continuing Operations

Navajo Nation Litigation

On June 18, 1999, the Navajo Nation served three of our subsidiaries, including Peabody Western Coal Company (Peabody Western), with a complaint that had been filed in the U.S. District Court for the District of Columbia. The Navajo Nation has alleged 16 claims, including Civil Racketeer Influenced and Corrupt Organizations Act (RICO) violations and fraud. The complaint alleges that the defendants jointly participated in unlawful activity to obtain favorable coal lease amendments. The plaintiff is seeking various remedies including actual damages of at least $600 million, which could be trebled under the RICO counts, punitive damages of at least $1 billion, a determination that Peabody Western s two coal leases have terminated due to Peabody Western s breach of these leases and a reformation of these leases to adjust the royalty rate to 20%. Subsequently, the court allowed the Hopi Tribe to intervene in this lawsuit and the Hopi Tribe is also seeking unspecified actual damages, punitive damages and reformation of its coal lease. One of our subsidiaries named as a defendant is now a subsidiary of Patriot. However, we are responsible for this litigation under the Separation Agreement entered into with Patriot in connection with the spin-off. On February 9, 2005, the U.S. District Court for the District of Columbia granted a consent motion to stay the litigation until further order of the court to allow parties to mediate. The mediation terminated without resolution and in March 2008 the court lifted the stay and litigation resumed.

The outcome of this litigation is subject to numerous uncertainties. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Salt River Project Agricultural Improvement and Power District Mine Closing and Retiree Health Care

Salt River Project and the other owners of the Navajo Generating Station filed a lawsuit on September 27, 1996, in the Superior Court of Maricopa County in Arizona seeking a declaratory judgment that certain costs relating to final reclamation, environmental monitoring work and mine decommissioning and costs primarily

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relating to retiree health care benefits are not recoverable by our subsidiary, Peabody Western, under the terms of a coal supply agreement dated February 18, 1977. The contract expires in 2011. The trial court subsequently ruled that the mine decommissioning costs were subject to arbitration but that the retiree health care costs were not subject to arbitration. All of the parties have negotiated and signed a comprehensive settlement to fully resolve all of the underlying claims and demands and to dismiss the associated litigation with prejudice, which became final and binding upon all of the parties on June 30, 2008. As a result of the retiree heath care cost settlement, we recorded pre-tax earnings of $56.9 million in 2008. We have a receivable for mine decommissioning costs of $90.4 million as of December 31, 2008 and $87.7 million as of December 31, 2007, and a receivable for retiree health care costs of $67.6 million as of December 31, 2008 included in Investments and other assets in the consolidated balance sheets.

Gulf Power Company Litigation

On June 22, 2006, Gulf Power Company filed a breach of contract lawsuit against one of our subsidiaries in the U.S. District Court, Northern District of Florida, contesting the force majeure declaration by our subsidiary under a coal supply agreement with Gulf Power Company and seeking damages for alleged past and future tonnage shortfalls of nearly five million tons under the agreement, which expired on December 31, 2007. In February 2008, the court denied our motion to dismiss the Florida lawsuit or to transfer it to Illinois and retained jurisdiction over the case.

The outcome of this litigation is subject to numerous uncertainties. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot reasonably be estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Claims and Litigation Relating to Indemnities or Historical Operations

Oklahoma Lead Litigation

Gold Fields is a dormant, non-coal producing entity that was previously managed and owned by Hanson PLC, our predecessor owner. In a February 1997 spin-off, Hanson PLC transferred ownership of Gold Fields to us, despite the fact that Gold Fields had no ongoing operations and we had no prior involvement in its past operations. Gold Fields is currently one of our subsidiaries. We indemnified TXU Group with respect to certain claims relating to a former affiliate of Gold Fields. A predecessor of Gold Fields formerly operated two lead mills near Picher, Oklahoma prior to the 1950s and mined, in accordance with lease agreements and permits, approximately 0.15% of the total amount of the crude ore mined in the county.

Gold Fields and two other companies are defendants in two class action lawsuits allegedly involving past operations near Picher, Oklahoma. The plaintiffs have asserted claims predicated on allegations of intentional lead exposure by the defendants and are seeking compensatory damages, punitive damages and the implementation of medical monitoring and relocation programs for the affected individuals. In December 2003, the Quapaw Indian tribe and certain Quapaw land owners filed a lawsuit against Gold Fields, five other companies and the U.S. The plaintiffs are seeking compensatory and punitive damages based on a variety of theories. In December 2007, the court dismissed the tribe s medical monitoring claim. In July 2008, the court dismissed the tribe s claim for interim and lost use damages under the CERCLA without prejudice to refile at the point the U.S. EPA selects a final remedy for the site. Gold Fields has filed a third-party complaint against the U.S. and other parties. In February 2005, the state of Oklahoma on behalf of itself and several other parties sent a notice to Gold Fields and other companies regarding a possible natural resources damage claim. All of the lawsuits are pending in the U.S. District Court for the Northern District of Oklahoma.

The outcome of litigation and these claims are subject to numerous uncertainties. Based our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Claims and Litigation

Environmental claims have been asserted against Gold Fields related to activities of Gold Fields or a former affiliate. Gold Fields or the former affiliate has been named a potentially responsible party (PRP) at five national priority list sites based on the Superfund Amendments and Reauthorization Act of 1986. Claims were asserted at 11 additional sites, bringing the total to 16, which have since been reduced to 12 by completion of work, transfer or regulatory inactivity. The number of PRP sites in and of itself is not a relevant measure of liability, because the nature and extent of environmental concerns varies by site, as does the estimated share of responsibility for Gold Fields or the former affiliate. Undiscounted liabilities for environmental cleanup-related costs for all of the sites noted above were $45.3 million as of December 31, 2008 and $43.5 million as of December 31, 2007, $7.6 million and $7.1 million of which was reflected as a current liability, respectively. These amounts represent those costs that we believe are probable and reasonably estimable. In September 2005, Gold Fields and other PRPs received a letter from the U.S. Department of Justice alleging that the PRP s mining operations caused the EPA to incur approximately $125 million in residential yard remediation costs at Picher, Oklahoma and will cause the EPA to incur additional remediation costs relating to historical mining sites. In September 2008, Gold Fields and other PRPs received letters from the U.S. Department of Justice and the EPA re-initiating settlement negotiations. Gold Fields is participating in the settlement discussions. Gold Fields believes it has meritorious defenses to these claims. Gold Fields is involved in other litigation in the Picher area, and we indemnified TXU Group with respect to a defendant as is more fully discussed under the Oklahoma Lead Litigation caption above. Significant uncertainty exists as to whether claims will be pursued against Gold Fields in all cases, and where they are pursued, the amount of the eventual costs and liabilities, which could be greater or less than the liabilities recorded in the consolidated balance sheets. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe these claims and litigation are likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Other

In addition, at times we become a party to other claims, lawsuits, arbitration proceedings and administrative procedures in the ordinary course of business in the U.S., Australia and other countries where we do business. Based on current information, we believe that the ultimate resolution of such other pending or threatened proceedings is not reasonably likely to have a material adverse effect on our financial position, results of operations or liquidity.

New York Office of the Attorney General Subpoena

The New York Office of the Attorney General sent a letter to us dated September 14, 2007 that referred to our plans to build new coal-fired electric generating units, and said that the increase in CO_2 emissions from the operation of these units, in combination with Peabody Energy s other coal-fired power plants, will subject Peabody Energy to increased financial, regulatory, and litigation risks. We currently have no electricity generating capacity in place. The letter included a subpoena issued under New York state law, which seeks information and documents relating to our analysis of the risks associated with climate change and possible climate change legislation or regulations, and its disclosure of such risks to investors. We believe that we have made full and proper disclosure of these potential risks.

Alaskan Villages Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina filed a lawsuit in the U.S. District Court for the Northern District of California against us, several owners of electricity generating facilities and several oil companies. The plaintiffs are the governing bodies of a village in Alaska that they contend is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for nuisance, and allege that the defendants have acted in concert and are jointly and severally liable for the plaintiffs damages. The suit seeks damages for lost property values and for the cost of relocating the village, which cost is alleged to be

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$95 million to $400 million. We believe that this lawsuit is without merit and intend to defend against and oppose it vigorously, but cannot predict its outcome. Based on our evaluation of the issues and their potential impact, the amount of any future loss cannot be reasonably estimated. However, based on current information, we believe this matter is likely to be resolved without a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

No matters were submitted to a vote of security holders during the quarter ended December 31, 2008.

Executive Officers of the Company

Set forth below are the names, ages as of February 25, 2009 and current positions of our executive officers. Executive officers are appointed by, and hold office at the discretion of, our Board of Directors.

Name	Age	Position
Gregory H. Boyce	54	Chairman and Chief Executive Officer, Director
Richard A. Navarre	48	President and Chief Commercial Officer
Michael C. Crews	42	Executive Vice President and Chief Financial Officer
Sharon D. Fiehler	52	Executive Vice President and Chief Administrative Officer
Eric Ford	54	Executive Vice President and Chief Operating Officer
Alexander C. Schoch	54	Executive Vice President Law and Chief Legal Officer

Gregory H. Boyce was elected Chairman of the Board on October 10, 2007 and has been a director of the Company since March 2005. He was named Chief Executive Officer Elect of the Company in March 2005, and assumed the position of Chief Executive Officer in January 2006. Mr. Boyce served as President of the Company from October 2003 to December 2007 and as Chief Operating Officer of the Company from October 2003 to December 2005. He previously served as Chief Executive Energy of Rio Tinto plc (an international natural resource company) from 2000 to 2003. Other prior positions include President and Chief Executive Officer of Kennecott Energy Company from 1994 to 1999 and President of Kennecott Minerals Company from 1993 to 1994. He has extensive engineering and operating experience with Kennecott and also served as Executive Assistant to the Vice Chairman of Standard Oil of Ohio from 1983 to 1984. Mr. Boyce serves on the board of directors of Marathon Oil Corporation. He is Vice Chairman of the World Coal Institute and the National Mining Association. He is a member of the National Coal Council (NCC) and the Coal Industry Advisory Board of the International Energy Agency. He is a Board member of the Business Roundtable, the American Coalition for Clean Coal Electricity (ACCCE). He is a member of the Board of Trustees of St. Louis Children s Hospital; the School of Engineering and Applied Science National Council at Washington University in St. Louis; and the Advisory Council of the University of Arizona s Department of Mining and Geological Engineering.

Richard A. Navarre was named our President and Chief Commercial Officer in January 2008. He served as our Executive Vice President of Corporate Development from July 2006 to January 2008 and as Chief Financial Officer from October 1999 to June 2008. He is a member of the Hall of Fame of the College of Business at Southern Illinois University Carbondale; a member of the Board of Advisors of the College of Business and Administration and the School of Accountancy of Southern Illinois University Carbondale; a member of the International Business Advisory Board of the University of Missouri St. Louis; a Director of the United Way of Greater St. Louis; a Director of the Missouri Historical Society; a member of Financial Executives International and the Civic Entrepreneurs

Organization; and a former chairman of the Bituminous Coal Operators Association.

Michael C. Crews was named our Executive Vice President and Chief Financial Officer in June 2008. He joined the Company in 1998 as Senior Manager of Financial Reporting, and has served as Assistant Corporate Controller, Director of Planning, Assistant Treasurer and Vice President of Operations Planning. Prior to joining us, Mr. Crews served for three years in financial positions with MEMC Electronic Materials, Inc. and six years at KPMG Peat Marwick in St. Louis. He has a Bachelor of Science degree in Accountancy from the University of Missouri at Columbia and a Master of Business Administration (MBA) degree from Washington University in St. Louis.

Sharon D. Fiehler has been our Executive Vice President and Chief Administrative Officer since January 2008, with executive responsibility for human resources, information services, procurement, flight services and facilities management. From April 2002 to January 2008, she served as our Executive Vice President of Human Resources and Administration. Ms. Fiehler joined us in 1981 as Manager Salary Administration and has held a series of employee relations, compensation and salaried benefits positions. She holds degrees in social work and psychology and a MBA, and prior to joining us was a personnel representative for Ford Motor Company. Ms. Fiehler is a Director of the Federal Reserve Bank of St. Louis. She is a member of the Executive Committee and Board of Directors of Junior Achievement of St. Louis; a member of the Board of Directors of the St. Louis Zoo Association; and Vice President of the Chancellor s Council of the University of Missouri St. Louis. She is also a 2008 YWCA Leader of Distinction Award recipient.

Eric Ford was named our Executive Vice President and Chief Operating Officer in March 2007, with responsibility for all of our global mining operations, as well as the areas of safety, operations improvement, engineering, and technical services. Mr. Ford has 35 years of extensive international management, operating and engineering experience, and most recently served as Chief Executive Officer of Anglo Coal Australia Pty Ltd. He joined Anglo Coal in 1971 and, after a series of increasingly complex operating assignments, was appointed President and Chief Executive Officer of Anglo American s joint venture coal mining operation in Colombia in 1998. In 2000, he returned to Anglo American Corporation as Executive Director of Operations for Anglo Platinum Corporation Limited. He was subsequently appointed Chief Executive Officer of Anglo Coal Australia Pty Ltd in 2001. Mr. Ford holds a Master of Science degree in Management Science from Imperial College in London and a Bachelor of Science degree in Mining Engineering (cum laude) from the University of the Witwatersrand in Johannesburg, South Africa. He was previously Deputy Chairman and a member of the Executive Committee of the Coal Industry Advisory Board of the International Energy Agency, and Vice Chairman and Director of the Minerals Council of Australia.

Alexander C. Schoch was named our Executive Vice President Law and Chief Legal Officer in October 2006 and our Secretary in May 2008, with responsibility for all of our legal and corporate secretary functions. Prior to joining us, Mr. Schoch served as Vice President and General Counsel for Emerson Process Management, an operating segment of Emerson Electric Company and leading supplier of process-automation products. Mr. Schoch also served in several legal positions with Goodrich Corporation, a global supplier to the aerospace and defense industries, from 1987 to 2004, including Vice President, Associate General Counsel and Secretary. Prior to that, he worked for Marathon Oil Company as an attorney in its international exploration and production division. Mr. Schoch holds a Juris Doctorate from Case Western Reserve University in Ohio, as well as a Bachelor of Arts in Economics from Kenyon College in Ohio. He is admitted to practice law in several states, and is a member of the American and International Bar Associations.

PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock is listed on the New York Stock Exchange, under the symbol BTU. As of February 13, 2009, there were 1,243 holders of record of our common stock.

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The table below sets forth the range of quarterly high and low sales prices for our common stock on the New York Stock Exchange during the calendar quarters indicated.

	High	Low
2007		
First Quarter	$ 44.60	$ 36.20
Second Quarter	55.76	39.96
Third Quarter	50.99	38.42
Fourth Quarter	62.55	47.52
2008		
First Quarter	$ 63.97	$ 42.05
Second Quarter	88.69	49.38
Third Quarter	88.39	39.06
Fourth Quarter	43.99	16.00

Dividend Policy

We paid quarterly dividends totaling $0.24 per share for each of the years ended December 31, 2008 and 2007. Most recently, our Board of Directors declared a dividend of $0.06 per share of Common Stock on January 28, 2009, payable on March 4, 2009, to stockholders of record on February 11, 2009. The declaration and payment of dividends and the amount of dividends will depend on our results of operations, financial condition, cash requirements, future prospects, any limitations imposed by our debt instruments and other factors deemed relevant by our Board of Directors. Limitations on our ability to pay dividends imposed by our debt instruments are discussed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Share Repurchases

Share Repurchase Program

In July 2005, our Board of Directors authorized a share repurchase program of up to 5% of the then outstanding shares of our common stock, approximately 13 million shares. The repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. In addition, our Board of Directors had previously authorized our Chairman and Chief Executive Officer to repurchase up to $100 million of our common stock outside the share repurchase program. In October 2008, our Board of Directors amended the share repurchase program to increase the total authorized amount to $1 billion. The amended repurchase program does not have an expiration date and may be discontinued at any time. Share repurchases made by us under this program in the year ended December 31, 2008 totaled 5.5 million shares for $199.8 million. As of December 31, 2008, there was $700.4 million available for share repurchases under the program.

The following table summarizes the share repurchases for the three months ended December 31, 2008:

	Total	Total Number of	Maximum Dollar Value that May Yet Be Used to

Period	Number of Shares Purchased	Average Price per Share	Shares Purchased as Part of Publicly Announced Program	Repurchase Shares Under the Publically Announced Program (In millions)
October 1 through October 31, 2008	4,332,106	$ 32.66	4,332,106	$ 700.4
November 1 through November 30, 2008				700.4
December 1 through December 31, 2008				700.4
Total	4,332,106	$ 32.66	4,332,106	

Item 6. *Selected Financial Data.*

The following table presents selected financial and other data about us for the most recent five fiscal years. The following table and the discussion of our results of operations in 2008 and 2007 in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations includes references to, and analysis of, our Adjusted EBITDA results. Adjusted EBITDA is used by management to measure operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies.

The selected financial data for all periods presented reflect the assets, liabilities and results of operations from subsidiaries spun off as Patriot as discontinued operations. We also have classified as discontinued operations those operations recently divested, as well as certain non-strategic mining assets held for sale where we have committed to the divestiture of such assets.

In October 2006, we acquired Excel and our results of operations for the year ended December 31, 2006 included the results of operations of the three operating mines and three development-stage mines (all of which are operating as of December 31, 2008) in New South Wales and Queensland, Australia from the date of acquisition.

On April 15, 2004, we acquired three coal operations from RAG Coal International AG. Our results of operations for the year ended December 31, 2004 include the results of operations of the two mines in Queensland, Australia and the results of operations of the Twentymile Mine in Colorado from the April 15, 2004 purchase date.

We have derived the selected historical financial data as of and for the years ended December 31, 2008, 2007, 2006, 2005 and 2004 from our audited financial statements. You should read the following table in conjunction with the financial statements, the related notes to those financial statements and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The results of operations for the historical periods included in the following table are not necessarily indicative of the results to be expected for future periods. In addition, the Risk Factors section of Item 1A of this report includes a discussion of risk factors that could impact our future results of operations.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
Results of Operations Data	**(Dollars in millions, except share and per share data and tons sold)**				
Revenues					
Sales	$ 6,036.3	$ 4,335.1	$ 3,944.9	$ 3,516.1	$ 2,680.8
Other revenues	557.1	210.0	106.0	81.8	82.2
Total revenues	6,593.4	4,545.1	4,050.9	3,597.9	2,763.0
Costs and Expenses					
Operating costs and expenses	4,617.2	3,532.5	3,088.2	2,828.5	2,206.5
Depreciation, depletion and amortization	406.2	352.2	284.2	244.9	205.3
Asset retirement obligation expense	48.2	23.7	14.2	19.9	14.8
Selling and administrative expenses	201.8	147.1	128.0	132.6	84.5
Other operating income:					
Net gain on disposal or exchange of assets	(72.9)	(88.6)	(53.5)	(44.4)	(18.1)
Income from equity affiliates		(14.5)	(22.8)	(15.2)	0.1
Operating Profit	1,392.9	592.7	612.6	431.6	269.9
Interest expense	226.2	235.0	139.1	98.0	90.9
Interest income	(10.1)	(7.1)	(11.3)	(9.1)	(4.0)
Income From Continuing Operations Before Income Taxes and Minority Interests	1,176.8	364.8	484.8	342.7	183.0
Income tax provision (benefit)	185.8	(72.9)	(85.7)	62.3	0.6
Minority interests	6.2	(2.3)	0.6	2.5	1.0
Income From Continuing Operations	984.8	440.0	569.9	277.9	181.4
Income (loss) from discontinued operations, net of tax	(31.3)	(175.7)	30.8	144.8	(6.1)
Net Income	$ 953.5	$ 264.3	$ 600.7	$ 422.7	$ 175.3

Basic Earnings Per Share From Continuing Operations	$	3.66	$	1.67	$	2.16	$	1.06	$	0.73
Diluted Earnings Per Share From Continuing Operations	$	3.63	$	1.63	$	2.12	$	1.04	$	0.71
Weighted average shares used in calculating basic earnings per share		268,860,528		264,068,180		263,419,344		261,519,424		248,732,744
Weighted average shares used in calculating diluted earnings per share		271,275,849		269,166,290		269,166,005		268,013,476		254,812,632
Dividends Declared Per Share	$	0.24	$	0.24	$	0.24	$	0.17	$	0.13
Other Data										
Tons sold (in millions)		255.5		236.1		221.4		213.7		200.3
Net cash provided by (used in) continuing operations:										
Operating activities	$	1,413.9	$	457.8	$	606.6	$	669.9	$	449.2
Investing activities		(531.5)		(538.9)		(2,055.6)		(506.3)		(742.8)
Financing activities		(375.8)		44.7		1,407.5		(38.9)		577.4
Adjusted EBITDA[1]		1,847.3		968.6		911.0		696.4		490.0
Additions to property, plant, equipment and mine development		266.2		438.8		391.9		440.1		96.9
Federal coal lease expenditures		178.5		178.2		178.2		118.4		114.7
Acquisitions, net		110.1				1,507.8				426.6
Balance Sheet Data (at period end)										
Total assets[2]	$	9,822.4	$	9,091.2	$	9,514.1	$	6,852.0	$	6,178.6
Total long-term debt		3,156.2		3,273.1		3,277.0		1,332.0		1,362.7
Total stockholders equity		2,903.8		2,519.7		2,338.5		2,178.5		1,724.6

(1) Adjusted EBITDA is defined as income from continuing operations before deducting net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization.

(2) Our asset and liability coal trading derivative positions and other corporate hedging activities are offset on a counterparty-by-counterparty basis if the contractual agreement provides for the net settlement of contracts with the counterparty in the event of default or termination of any one contract in accordance with

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FASB Staff Position FIN 39-1, which was implemented January 1, 2008. The impact of netting resulted in a decrease in our total asset figure for 2007. The impact on total assets for 2006, 2005 and 2004 was immaterial.

Adjusted EBITDA is calculated as follows (unaudited):

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(Dollars in millions)				
Income from continuing operations	$ 984.8	$ 440.0	$ 569.9	$ 277.9	$ 181.4
Income tax provision (benefit)	185.8	(72.9)	(85.7)	62.3	0.6
Depreciation, depletion and amortization	406.2	352.2	284.2	244.9	205.3
Asset retirement obligation expense	48.2	23.7	14.2	19.9	14.8
Interest expense	226.2	235.0	139.1	98.0	90.9
Interest income	(10.1)	(7.1)	(11.3)	(9.1)	(4.0)
Minority interests	6.2	(2.3)	0.6	2.5	1.0
Adjusted EBITDA	$ 1,847.3	$ 968.6	$ 911.0	$ 696.4	$ 490.0

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations.*

Overview

We are the largest private sector coal company in the world, with majority interests in 30 coal operations located throughout all major U.S. coal producing regions, except Appalachia, and international interests in Australia and Venezuela. In 2008, we produced 223.7 million tons of coal and sold 255.5 million tons of coal. Our U.S. sales represented 18% of U.S. coal consumption and were approximately 30% greater than the sales of our closest U.S. competitor.

U.S. coal consumption was approximately 1.1 billion tons in 2008, based on Energy Information Administration (EIA) estimates. Coal is primarily used for baseload electricity requirements. In 2008, coal s share of electricity generation was approximately 50%. Between 2007 and 2030, the EIA projects coal-based electricity generation to grow 19%, outpacing all other primary fuel sources, representing 164 million tons of additional coal demand. During that same time frame, new coal-to-liquids facilities for both heat and power and liquids production is projected by the EIA to add another 70 million tons of coal demand. Coal production is expected to shift to western and interior U.S. locations to offset Appalachian declines. Specifically, production from facilities located west of the Mississippi River is projected to provide most of the incremental growth, comprising a 61% share of total production in 2030 versus 58% in 2007.

Global coal consumption has grown faster than any other fuel, averaging nearly 5% per year between 2000 and 2007. The International Energy Agency (IEA) projects demand for coal will rise more than any other fuel in absolute terms, accounting for over a third of the increase in energy use between 2006 and 2030. China and India combined represent 85% of the projected increase in world coal demand. Most of the increase in demand for coal comes from the power generation sector. Global electricity generation is projected by the IEA to rise 76% from 18,921 terawatt hours in 2006 to 33,265 terawatt hours in 2030. The IEA estimates 613 gigawatts of new power generating capacity is under construction around the world, approximately one-third of which is coal-based. The IEA expects coal to remain the main fuel for power generation worldwide, comprising 44% of the generation mix in 2030 versus 41% in 2006. In total, the IEA projects global primary coal demand will increase 61%, or approximately 2.6 billion tonnes by 2030.

For the year ended December 31, 2008, 82% of our total sales (by volume) were to U.S. electricity generators, 16% were to customers outside the U.S. and 2% were to the U.S. industrial sector. We typically sell coal to utility customers under long-term contracts (those with terms longer than one year). During 2008, approximately 90% of our worldwide sales (by volume) were under long-term contracts. As discussed more fully in Item 1A. Risk Factors, our results of operations in the near-term could be negatively impacted by the recent economic downturn, poor weather conditions, unforeseen geologic conditions or equipment problems at mining locations and by the availability of transportation for coal shipments. On a long-term basis, our results of operations could be impacted by our ability to secure or acquire high-quality coal reserves, find replacement buyers for coal under contracts with comparable terms to existing contracts, or the passage of new or expanded regulations that could limit our ability to mine, increase our mining costs, or limit our customers ability to utilize coal as fuel for electricity generation. In the past, we have achieved production levels that are relatively consistent with our projections. We may adjust our production levels further in response to changes in market demand.

We conduct business through four principal operating segments: Western U.S. Mining, Midwestern U.S. Mining, Australian Mining and Trading and Brokerage.

The principal business of the Western and Midwestern U.S. Mining segments is the mining, preparation and sale of steam coal, sold primarily to electric utilities. Our Western U.S. Mining operations consist of our Powder River Basin, Southwest and Colorado operations and are characterized by predominantly surface extraction processes, lower sulfur content and Btu of coal, and higher customer transportation costs (due to longer shipping distances). Geologically, the Western U.S. Mining operations mine bituminous and subbituminous coal deposits.

Our Midwestern U.S. Mining operations consist of our Illinois and Indiana operations and are characterized by a mix of surface and underground extraction processes, higher sulfur content and Btu of coal and lower customer transportation costs (due to shorter shipping distances). Geologically, the Midwestern U.S. Mining operations mine bituminous coal deposits.

Australian Mining operations are characterized by both surface and underground extraction processes, mining various qualities of low-sulfur, high Btu coal (metallurgical coal) as well as steam coal primarily sold to an international customer base with a small portion sold to Australian steel producers and power generators.

We own a 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. The Paso Diablo Mine produced approximately 4.8 million tons of steam coal in 2008 for export to the U.S. and Europe. During 2008, the Paso Diablo Mine contributed $5.7 million to segment Adjusted EBITDA in Corporate and Other Adjusted EBITDA and paid a dividend of $19.9 million. At December 31, 2008, our investment in Paso Diablo was $54.2 million.

Metallurgical coal is produced primarily from five of our Australian mines. Metallurgical coal is approximately 3% of our total sales volume, but represents a larger share of our revenue, approximately 23% in 2008.

In addition to our mining operations, which comprised 90% of revenues in 2008, we generate revenues and additional cash flows from our Trading and Brokerage segment (9% of revenues) and other activities, including transactions utilizing our vast natural resource position (selling non-core land holdings and mineral interests).

We also continue to pursue development of coal-fueled generating and Btu Conversion projects in areas of the U.S. where electricity demand is strong and where there is access to land, water, transmission lines and low-cost coal.

Coal-fueled generating projects may involve mine-mouth generating plants using our surface lands and coal reserves. Our ultimate role in these projects could take numerous forms, including, but not limited to, equity partner, contract miner or coal sales. Currently, we own 5.06% of the 1,600-megawatt Prairie State Energy Campus that is under construction in Washington County, Illinois.

The long-term demand for oil and natural gas around the world is expected to lead to an increase in demand for unconventional sources of transportation fuel. We are exploring Btu Conversion projects designed to expand the uses of coal through coal-to-liquids and coal gasification technologies. Currently, we are pursuing development of a coal-to-gas facility in Muhlenberg County, Kentucky. The facility, known as Kentucky NewGas, is a planned "mine-mouth" gasification project using ConocoPhillips proprietary E-Gas(tm) technology to produce clean synthesis gas with carbon storage potential. The plant, assuming all necessary permits and financing are obtained and following selection of partners and sale of a majority of the output of

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each plant, could be operational following a four-year construction phase. We also own a minority interest in GreatPoint Energy, Inc., which is commercializing its coal-to-pipeline quality natural gas technology.

We are participating in the advancement of clean coal technologies, including carbon capture and storage, in the U.S., China and Australia. We are a founding member of the FutureGen Industrial Alliance, a non-profit company working in partnership with the U.S. DOE, which under its new configuration, would develop multiple carbon capture and storage sites. We are the only non-Chinese equity partner in GreenGen, a near-zero emissions coal-fueled power plant with carbon capture and storage. And in Australia, we made a 10-year commitment to fund the Australian COAL21 Fund designed to support clean coal technology demonstration projects and research in Australia.

Results of Operations

The results of operations for all periods presented reflect the assets, liabilities and results of operations from subsidiaries spun off as Patriot as discontinued operations. We also have classified as discontinued operations certain non-strategic mining assets held for sale where we have committed to the divestiture of such assets and operations recently divested.

Adjusted EBITDA

The discussion of our results of operations below includes references to and analysis of our segments Adjusted EBITDA results. Adjusted EBITDA is defined as income from continuing operations before deducting net interest expense, income taxes, minority interests, asset retirement obligation expense and depreciation, depletion and amortization. Adjusted EBITDA is used by management to measure our segments operating performance, and management also believes it is a useful indicator of our ability to meet debt service and capital expenditure requirements. Because Adjusted EBITDA is not calculated identically by all companies, our calculation may not be comparable to similarly titled measures of other companies. Adjusted EBITDA is reconciled to its most comparable measure, under generally accepted accounting principles, in Note 22 to our consolidated financial statements.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Summary

Higher average sales prices and volumes across all operating regions, particularly in Australia, contributed to a 45.1% increase in revenues to $6.59 billion. Segment Adjusted EBITDA rose 94.3% to $2.09 billion primarily on the higher pricing mentioned above and favorable results from Trading and Brokerage operations. Increases in sales prices and volumes were partially offset by higher commodity, material, supply, sales-related and labor costs in all operating regions. Income from continuing operations was $984.8 million in 2008, or $3.63 per diluted share, 123.8% above 2007 income from continuing operations of $440.0 million, or $1.63 per diluted share.

Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase	
	2008	2007	Tons	%
	(Tons in millions)			

Western U.S. Mining	169.7	161.4	8.3	5.1%
Midwestern U.S. Mining	30.7	29.6	1.1	3.7%
Australian Mining	23.9	21.0	2.9	13.8%
Trading and Brokerage	31.2	24.1	7.1	29.5%
Total tons sold	255.5	236.1	19.4	8.2%

Revenues

The following table presents revenues for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2008	2007	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 2,533.1	$ 2,063.2	$ 469.9	22.8%
Midwestern U.S. Mining	1,154.6	987.1	167.5	17.0%
Australian Mining	2,275.2	1,138.9	1,136.3	99.8%
Trading and Brokerage	601.8	320.7	281.1	87.7%
Other	28.7	35.2	(6.5)	(18.5)%
Total revenues	$ 6,593.4	$ 4,545.1	$ 2,048.3	45.1%

Total revenues increased in 2008 compared to the prior year across all operating segments. The primary drivers of the increases included the following:

An increase in average sales price at our Australian Mining operations (75.6%), primarily driven by the strength of metallurgical coal prices on our Australia contracts that reprice annually in the second quarter of each year.

U.S. Mining operations average sales price increased over the prior year (15.2%) driven by the benefit of higher priced coal supply agreements signed in recent years.

Australia s volumes increased over the prior year (13.8%) from strong demand during the first three quarters of 2008 and additional production from recently completed mines. Year-over-year increases were partially offset by heavy rainfall and flooding in Queensland during the first quarter of 2008 and customer shipment deferrals in the fourth quarter of 2008 due to the global economic slowdown.

Increased demand also led to higher volumes across our U.S. operating segments, which overcame slightly lower volumes at some of our Midwestern U.S. Mining surface operations due to poor weather in that operating region that impacted production during the first and second quarters. The volume increase of 5.1% at our Western U.S. Mining operations resulted from greater throughput from capital improvements and contributions from our new El Segundo Mine, partially offset by the flooding in the midwestern U.S. that impacted railroad shipping performance related to western U.S. production during the second quarter of 2008.

Trading and Brokerage operations revenues increased over the prior year due to increased trading positions allowing us to capture market movements derived from the volatility of both domestic and international coal markets.

Also impacting year-over-year revenues in our Western U.S. Mining operations was an agreement to recover previously recognized postretirement healthcare and reclamation costs of $56.9 million in the second quarter of 2008. The agreement is discussed in Note 20 to the consolidated financial statements.

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Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase (Decrease) to Segment Adjusted EBITDA $	Increase (Decrease) to Segment Adjusted EBITDA %
	(Dollars in millions)			
Western U.S. Mining	$ 681.3	$ 595.4	$ 85.9	14.4%
Midwestern U.S. Mining	177.3	200.0	(22.7)	(11.4)%
Australian Mining	1,017.0	166.1	850.9	512.3%
Trading and Brokerage	218.9	116.6	102.3	87.7%
Total Segment Adjusted EBITDA	$ 2,094.5	$ 1,078.1	$ 1,016.4	94.3%

Adjusted EBITDA from our Western U.S. Mining operations increased in 2008 over the prior year primarily driven by an overall increase in average sales prices per ton across the region ($2.10) and higher volumes in the region due to increased demand and greater throughput as a result of capital improvements. Also contributing to the increase was the recovery of postretirement healthcare and reclamation costs discussed above. Partially offsetting the pricing and volume contributions were higher per ton costs ($1.78). The cost increases were primarily due to higher sales related costs, higher material, supply and labor costs, higher repair and maintenance costs in the Powder River Basin and increased commodity costs, net of hedging activities, driven by higher average fuel and explosives pricing.

Midwestern U.S. Mining operations Adjusted EBITDA decreased in 2008 as increases in average sales price per ton ($4.22) were offset by cost increases resulting from higher costs for commodities, net of hedging activities, driven by higher average fuel and explosives prices, as well as higher material, supply and labor costs. Heavy rains and flooding in the midwestern U.S. affected sales volume at some of our mines, particularly in the first half of the year. Also affecting the Midwestern U.S. Mining segment was the decrease in revenues from coal sold to synthetic fuel plants in the prior year ($28.9 million) due to the producers exiting the synthetic fuel market after expiration of federal tax credits at the end of 2007.

Our Australian Mining operations Adjusted EBITDA increased in 2008 primarily due to higher pricing negotiated in the second quarter of 2008 ($40.86 per ton), higher overall volumes as a result of strong export demand and contributions from our recently completed mines, and lower demurrage costs. These favorable impacts were partially offset by higher fuel costs, an increase in labor and overburden removal expenses and higher contractor costs (five of ten Australian mines are managed utilizing contract miners).

Trading and Brokerage operations Adjusted EBITDA increased in 2008 over the prior year due to increased trading volumes and higher coal price volatility.

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Income From Continuing Operations Before Income Taxes and Minority Interests

The following table presents income before income taxes and minority interests for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Increase (Decrease) to Income $	Increase (Decrease) to Income %
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 2,094.5	$ 1,078.1	$ 1,016.4	94.3%
Corporate and Other Adjusted EBITDA	(247.2)	(109.5)	(137.7)	(125.8)%
Depreciation, depletion and amortization	(406.2)	(352.2)	(54.0)	(15.3)%
Asset retirement obligation expense	(48.2)	(23.7)	(24.5)	(103.4)%
Interest expense	(226.2)	(235.0)	8.8	3.7%
Interest income	10.1	7.1	3.0	42.3%
Income from continuing operations before income taxes and minority interests	$ 1,176.8	$ 364.8	$ 812.0	222.6%

Income from continuing operations before income taxes and minority interests increased over the prior year primarily due to the higher Total Segment Adjusted EBITDA discussed above, partially offset by lower Corporate and Other Adjusted EBITDA, higher depreciation, depletion and amortization, and higher asset retirement obligation expense.

Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income from our joint ventures, net gains on asset disposals, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as generation development and Btu Conversion development costs. The decrease in Corporate and Other Adjusted EBITDA during 2008 compared to 2007 was due to the following:

Higher selling and administrative expenses ($54.7 million) primarily driven by an increase in performance-based incentive costs and legal expenses;

Cost reimbursement and partner fees received in the prior year for the Prairie State project, primarily related to the entrance of new project partners ($29.5 million);

Lower net gains on disposals or exchanges of assets ($15.7 million). 2008 activity included a gain of $54.0 million on the sale of approximately 58 million tons of non-strategic coal reserves and surface lands located in Kentucky. 2007 activity included a gain of $50.5 million on the exchange of oil and gas rights and assets in more than 860,000 acres in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for coal reserves in West Virginia and Kentucky and cash proceeds. The prior year also included a gain of $26.4 million on the sale of approximately 172 million tons of coal reserves and surface lands to the Prairie State equity partners; and

Lower equity income ($15.5 million) from our 25.5% interest in Carbones del Guasare (owner and operator of the Paso Diablo Mine in Venezuela) and higher costs associated with Btu Conversion activities of $14.3 million in 2008.

Depreciation, depletion and amortization was higher in 2008 compared to the prior year because of increased depletion across our operating platform resulting from the volume increases and the impact of mining higher value coal reserves. In addition, depreciation and depletion increases resulted from our recently completed Australian mines and depletion at our El Segundo Mine.

Asset retirement obligation expense increased in 2008 as compared to the prior year due to an increase in the ongoing and closed mine reclamation rates that reflect higher fuel, labor and re-vegetation costs, as well as an overall increase in the number of acres disturbed. The addition of the El Segundo Mine, which was completed in June 2008, also contributed to higher asset retirement obligation expense.

Net Income

The following table presents net income for the years ended December 31, 2008 and 2007:

	Year Ended December 31, 2008	2007	Increase (Decrease) to Income $	%
	(Dollars in millions)			
Income before income taxes and minority interests	$ 1,176.8	$ 364.8	$ 812.0	222.6%
Income tax (provision) benefit	(185.8)	72.9	(258.7)	(354.9)%
Minority interests	(6.2)	2.3	(8.5)	(369.6)%
Income from continuing operations	984.8	440.0	544.8	123.8%
Loss from discontinued operations	(31.3)	(175.7)	144.4	82.2%
Net income	$ 953.5	$ 264.3	$ 689.2	260.8%

Net income increased in 2008 compared to the prior year due to the increase in income from continuing operations before incomes taxes and minority interests discussed above. The tax provision increase over the prior year is the result of the current year increased pre-tax earnings ($292.6 million) combined with the valuation allowance release against federal net operating loss credits recognized into income in the prior year ($197.8 million). These increases were partially offset by the non-cash tax benefit from the remeasurement of non-U.S. dollar denominated income tax accounts as a result of the strengthening of the Australian dollar in 2007 as compared to weakening of the Australian dollar in 2008 ($121.3 million), the favorable rate difference resulting from higher foreign generated income ($110.8 million) and the release of a valuation allowance against a portion of our Australia net operating loss carryforwards in the current year ($45.3 million) as a result of significantly higher earnings resulting from the higher contract pricing that was secured during 2008. Net income for 2008 was also impacted by a lower loss from discontinued operations as compared to the prior year due primarily to losses incurred for Patriot operations in 2007. The loss from discontinued operations for 2008 related to operating losses, net of a gain on sale of assets previously held for sale ($19.6 million) and an $11.7 million write-off of an excise tax refund receivable (net of tax) as a result of an April 2008 U.S. Supreme Court ruling (see Note 2 to the consolidated financial statements).

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Summary

Higher average sales prices across all U.S. regions and increased volumes, primarily from Australian Mining operations, contributed to a 12.2% increase in revenues to $4.55 billion compared to 2006. Segment Adjusted EBITDA increased 3.8% to $1.08 billion primarily on higher prices in the Western U.S. Mining operations and increased results from Trading and Brokerage operations. Increases in sales volumes and prices in our U.S. mining operations were partially offset by challenges experienced during the period such as ongoing shipping constraints from port congestion in Australia; geologic and equipment issues, higher commodity costs, as well as a weaker U.S. dollar against the Australian Dollar. Also, negatively impacting Australian Mining results was lower metallurgical coal prices associated with annual contracts that began in April 2007. Income from continuing operations was $440.0 million in 2007, or $1.63 per diluted share, a decrease of 22.8% from 2006 income from continuing operations of $569.9 million, or $2.12 per diluted share.

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Tons Sold

The following table presents tons sold by operating segment for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase	
	2007	2006	Tons	%
	(Tons in millions)			
Western U.S. Mining	161.4	160.5	0.9	0.6%
Midwestern U.S. Mining	29.6	28.7	0.9	3.1%
Australian Mining	21.0	10.8	10.2	94.4%
Trading and Brokerage	24.1	21.4	2.7	12.6%
Total tons sold	236.1	221.4	14.7	6.6%

Revenues

The table below presents revenues for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Revenues	
	2007	2006	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 2,063.2	$ 1,703.4	$ 359.8	21.1%
Midwestern U.S. Mining	987.1	858.5	128.6	15.0%
Australian Mining	1,138.9	833.0	305.9	36.7%
Trading and Brokerage	320.7	652.0	(331.3)	(50.8)%
Other	35.2	4.0	31.2	780.0%
Total revenues	$ 4,545.1	$ 4,050.9	$ 494.2	12.2%

Total revenues increased in 2007 compared to 2006 across all mining operations. The primary drivers of the increases included the following:

Prices in our Western U.S. Mining operations increased due to a sales realization increase of approximately 29% for our premium Powder River Basin product and an average increase across all U.S. regions of 16%.

Midwestern U.S. Mining revenues increased due to higher revenues from coal sold to synthetic fuel plants as those plants were idled for part of 2006.

Increased volumes from our Australian Mining operations. Volumes related to operations acquired in the October 2006 Excel acquisition accounted for 10.9 million tons of the increase to tons sold. Offsetting this increase was lower average sales prices in our Australian Mining operations related to lower metallurgical contract pricing and a significant change in sales mix resulting in higher thermal export and domestic product sales. Volumes were unfavorably impacted at some of our Australian Mining operations as a result of damaged rails and further amplified port and rail congestion throughout the year, in addition to adverse weather events that affected production.

Partially offsetting sales price and volume increases was the continued shift towards trading contracts versus brokerage contracts in our Trading and Brokerage operations. Trading and Brokerage operations sales decreased during 2007 as the amount of brokerage business was reduced and replacement business was in the form of traded contracts. Contracts for trading activity are recorded at net margin in other revenues, whereas contracts for brokerage activity are recorded at gross sales price to revenues and operating costs.

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Segment Adjusted EBITDA

The following table presents segment Adjusted EBITDA for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Segment Adjusted EBITDA	
	2007	2006	$	%
	(Dollars in millions)			
Western U.S. Mining	$ 595.4	$ 473.1	$ 122.3	25.9%
Midwestern U.S. Mining	200.0	186.2	13.8	7.4%
Australian Mining	166.1	286.8	(120.7)	(42.1)%
Trading and Brokerage	116.6	92.6	24.0	25.9%
Total Segment Adjusted EBITDA	$ 1,078.1	$ 1,038.7	$ 39.4	3.8%

Adjusted EBITDA from our Western U.S. Mining operations increased in 2007 over 2006 primarily related to the overall increase in average sales prices from our Powder River Basin operations. Partially offsetting higher average sales prices were higher costs associated with equipment repairs and maintenance and higher add-on taxes and royalties driven by higher sales prices compared to the prior year, mine shutdown for maintenance in our Colorado mine, higher fuel costs and adverse weather conditions in the Powder River Basin and capital project delays.

Midwestern U.S. Mining operations Adjusted EBITDA increased in 2007 over 2006 as both volumes and prices per ton saw moderate increases. Results improved compared to 2006 as benefits of higher volumes and sales prices were offset by higher costs for commodities, including fuel. The 2007 results were also positively impacted by higher revenues from coal sold to synthetic fuel facilities of $12.5 million as customers idled their synthetic fuel plants for a portion of 2006.

Our Australian Mining operations Adjusted EBITDA decreased in 2007 from 2006 primarily due to approximately $31 million of higher costs resulting from the weakening U.S. dollar (higher costs of approximately $112 million were offset by hedging gains of $81 million); higher congestion-related demurrage costs (approximately $50 million); lower pricing on annually repriced metallurgical coal contracts; and, rail and port congestion at Dalrymple Bay Coal Terminal and the Port of Newcastle. Dalrymple Bay Coal Terminal had been experiencing queues of over 41 vessels (approximately a 24-day load time) down from 50 vessels in the second quarter (approximately a 34-day delay). Partially offsetting these decreases were the full year contributions from our mines acquired in the Excel acquisition and a $6.3 million insurance recovery on a business interruption claim in the first half of 2007. Our Australian mines acquired in 2006 experienced shipping difficulties and damaged rail lines resulting from a storm late in 2007. The Port of Newcastle was closed for several days in 2007 due to a storm, with up to 79 vessels in the queue (a 35 40 day wait).

Trading and Brokerage operations Adjusted EBITDA increased in 2007 over 2006 as the results reflected higher international trading gains, resulting from higher volumes and pricing due to expanded global trading activities, strong supply/demand fundamentals and tightened seaborne market conditions.

Income From Continuing Operations Before Income Taxes and Minority Interests

The following table presents income before income taxes and minority interests for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Income	
	2007	2006	$	%
	(Dollars in millions)			
Total Segment Adjusted EBITDA	$ 1,078.1	$ 1,038.7	$ 39.4	3.8%
Corporate and Other Adjusted EBITDA	(109.5)	(127.7)	18.2	14.3%
Depreciation, depletion and amortization	(352.2)	(284.2)	(68.0)	(23.9)%
Asset retirement obligation expense	(23.7)	(14.2)	(9.5)	(66.9)%
Interest expense	(235.0)	(139.1)	(95.9)	(68.9)%
Interest income	7.1	11.3	(4.2)	(37.2)%
Income from continuing operations before income taxes and minority interests	$ 364.8	$ 484.8	$ (120.0)	(24.8)%

Income from continuing operations before income taxes and minority interests in 2007 was lower than 2006 primarily due to higher interest expense and higher depreciation, depletion and amortization related to the acquisition of Excel in late 2006.

Corporate and Other Adjusted EBITDA results include selling and administrative expenses, equity income from our joint ventures, net gains on asset disposals or exchanges, costs associated with past mining obligations and revenues and expenses related to our other commercial activities such as generation development, Btu Conversion development and resource management. The improvement in Corporate and Other Adjusted EBITDA in 2007 compared to 2006 includes the following:

Higher gains on asset disposals and exchanges of $35.1 million. The 2007 activity included a gain of $26.4 million on the sale of approximately 172 million tons of coal reserves to the Prairie State equity partners. Our 2007 activity also included a gain of $50.5 million on the exchange of our coalbed methane and oil and gas rights in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for high-Btu coal reserves located in West Virginia and Kentucky and cash proceeds. In comparison, the 2006 activity included a $39.2 million gain on an exchange with the Bureau of Land Management of approximately 63 million tons of leased coal reserves at our Caballo mining operation for approximately 46 million tons of coal reserves contiguous with our North Antelope Rochelle mining operation and other gains on asset disposals totaling $14.3 million;

Higher past mining obligation expenses of $15.5 million resulting from increased retiree healthcare costs due to higher than anticipated healthcare utilization by retirees, particularly related to prescription drugs;

Higher selling and administrative expenses of $19.1 million primarily resulting from the implementation of a new enterprise resource planning system and other corporate development initiatives; and

Lower equity income of $6.8 million from our 25.5% interest in Carbones del Guasare (owner and operator of the Paso Diablo Mine in Venezuela), which primarily resulted from trucking issues experienced earlier in the year, a temporary shortage of explosives and delays in receiving equipment, which impacted operations.

Depreciation, depletion and amortization increased $68.0 million primarily related to the addition of the Australian operations acquired in late 2006.

Interest expense increased $95.9 million primarily due to approximately $1.8 billion in new debt issued or assumed as part of the Excel acquisition in the second half of 2006.

Net Income

The following table presents net income for the years ended December 31, 2007 and 2006:

	Year Ended December 31,		Increase (Decrease) to Income	
	2007	2006	$	%
	(Dollars in millions)			
Income before income taxes and minority interests	$ 364.8	$ 484.8	$ (120.0)	(24.8)%
Income tax benefit	72.9	85.7	(12.8)	(14.9)%
Minority interests	2.3	(0.6)	2.9	483.3%
Income from continuing operations	440.0	569.9	(129.9)	(22.8)%
Income (loss) from discontinued operations	(175.7)	30.8	(206.5)	(670.5)%
Net income	$ 264.3	$ 600.7	$ (336.4)	(56.0)%

Income from continuing operations decreased in 2007 compared to prior year due to the decrease in income before income taxes and minority interests discussed above and a lower income tax benefit compared to 2006. The decrease in the income tax benefit for the year ended 2007 related primarily to a $56.0 million foreign currency impact on deferred taxes as a result of increases in Australian dollar/U.S. dollar exchange rates and $33.2 million lower tax reserves than in 2006. This decrease was partially offset by lower pre-tax income, a $10.3 million increase in released valuation allowances and $24.3 million of additional tax credits. Minority interests increased primarily from the absorption of losses in excess of the minority interest capital contribution at one of our mines, partially offset by lower earnings allocable to partners.

Outlook

Near-Term Outlook

The current global financial slowdown has reduced gross domestic product expectations for U.S., China and other major world economies, which is expected to temper the growth of coal demand in the near term. As a result, we expect our 2009 prices to be lower than 2008 levels for our unpriced 2009 Australian-based metallurgical and thermal coal (see further discussion of unpriced coal below).

Fourth quarter 2008 global steel production declined 19% compared to fourth quarter 2007 due to the softening worldwide economies. Steel production in 2009 is anticipated to be as much as 20% lower than 2008. We estimate lower steel production will reduce 2009 seaborne metallurgical coal demand up to 40 million metric tonnes. In response to expected declines in demand, met coal producers have been reducing planned production levels. As of January 2009, approximately 30 million metric tonnes of seaborne met coal production cuts have been announced.

In January 2009, we announced planned production cuts of up to 2 million tons of Australian-based metallurgical coal to match expected changes in demand due to the global recession. As of January 2009, we have 4 to 5 million tons of expected Australian-based metallurgical coal production available to be priced for the last three quarters of 2009.

By the end of 2008, published thermal coal prices in most major markets declined from their mid-2008 highs, largely reversing gains from the first half of 2008. The decline was initiated by the accelerated liquidation of positions by financial counterparties that was followed by mild weather across the northern hemisphere during the third quarter of 2008 and the onset of the global economic downturn over the second half of the year.

As of January 2009, we have 5 to 6 million tons of Australian-based thermal coal available to be priced for the last three quarters of 2009.

In the U.S., declining gross domestic product is expected to lead to reduced electricity demand for 2009. In addition, higher-than-normal stockpiles, low natural gas prices and lower U.S. exports could dampen 2009 U.S. coal demand by up to 60 to 70 million tons. U.S. coal production is adjusting to anticipated changes in demand, with approximately 40 million tons of announced production cuts from 50% of the U.S. production base as of January 2009.

In January 2009, we announced planned reductions in 2009 Powder River Basin production of 10 million tons to better match production with expected demand. Our U.S. production is largely sold out for 2009.

We are targeting full-year 2009 production of 190 to 195 million tons in the U.S. and 22 to 24 million tons in Australia with total sales in the range of 230 to 250 million tons.

We rely on ongoing access to the worldwide financial markets for capital, insurance, hedging and investments through a wide variety of financial instruments and contracts. To the extent these markets are not available or increase significantly in cost, this could have a negative impact on our ability to meet our business goals. Similarly many of our customers and suppliers rely on the availability of the financial markets to secure the necessary financing and financial surety (letters of credit, performance bonds, etc.) to complete transactions with us. To the extent customers and suppliers are not able to secure this financial support, it could have a negative impact on our results of operations and/or counterparty credit exposure.

We continue to manage costs and operating performance to mitigate external cost pressures, geologic conditions and potentially adverse port and rail performance. We have experienced increases in operating costs related to fuel, explosives, steel, tires, contract mining and healthcare, and have taken measures to mitigate the increases in these costs, including a company-wide initiative to instill best practices at all operations. We may also encounter poor geologic conditions, lower third-party contract miner or brokerage performance or unforeseen equipment problems that limit our ability to produce at forecasted levels. To the extent upward pressure on costs exceeds our ability to realize sales increases, or if we experience unanticipated operating or transportation difficulties, our operating margins would be negatively impacted. See Cautionary Notice Regarding Forward-Looking Statements and Item 1A. of this report for additional considerations regarding our outlook.

Long-term Outlook

Given the current global economic conditions, the near-term is less certain. However, our long-term outlook remains positive. Coal has been the fastest-growing fuel for each of the past five years, with consumption growing nearly twice as fast as total energy use.

The IEA s World Energy Outlook estimates world primary energy demand will grow 45% between 2006 and 2030, with demand for coal rising more than any other fuel and comprising more than a third of the expected increase in energy use. China and India alone account for more than half of the expected incremental energy demand. Currently, 200 gigawatts of coal-fired electricity generating plants are under construction around the world, representing nearly 700 million tons of annual coal demand expected to come online in the next several years. In the U.S., 30 units are currently under construction in 19 states, representing more than 16 gigawatts of capacity and approximately 70 million tons of annual coal demand.

We believe that Btu Conversion applications such as coal-to-gas (CTG) and coal-to-liquids (CTL) plants represent a significant avenue for potential long-term industry growth. The EIA continues to project an increase in demand for unconventional sources of transportation fuel, including CTL, which is estimated to add 70 million tons of annual U.S. coal demand by 2030. In addition, China and India are developing CTG and CTL facilities.

Enactment of laws and passage of regulations regarding greenhouse gas emissions by the U.S. or some of its states or by other countries, or other actions to limit carbon dioxide emissions, could result in electricity generators switching from coal to other fuel sources. We continue to support clean coal technology development and voluntary initiatives addressing global climate change through our participation as a founding member of the FutureGen Alliance and the Australian COAL21 Fund, and through our participation in the Power Systems Development Facility, the PowerTree Carbon Company LLC, the Midwest Geopolitical Sequestration Consortium and the Asia-Pacific Partnership for Clean Development and Climate. In addition, we are the only non-Chinese equity partner in GreenGen, a planned near-zero emissions coal-fueled power plant with carbon capture and storage which is under development in China.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. Generally accepted accounting principles require that we make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

Employee-Related Liabilities

We have long-term liabilities for our employees postretirement benefit costs and defined benefit pension plans. Detailed information related to these liabilities is included in Notes 14 and 15 to our consolidated financial statements. Liabilities for postretirement benefit costs and workers compensation obligations are not funded. Our pension obligations are funded in accordance with the provisions of federal law. Expense for the year ended December 31, 2008 for the pension and postretirement liabilities totaled $74.4 million, while funding payments were $89.5 million.

Each of these liabilities are actuarially determined and we use various actuarial assumptions, including the discount rate and future cost trends, to estimate the costs and obligations for these items. Our discount rate is determined by utilizing a hypothetical bond portfolio model which approximates the future cash flows necessary to service our liabilities.

We make assumptions related to future trends for medical care costs in the estimates of retiree health care and work-related injuries and illnesses obligations. Our medical trend assumption is developed by annually examining the historical trend of our cost per claim data. In addition, we make assumptions related to future compensation increases and rates of return on plan assets in the estimates of pension obligations.

If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could differ materially from our current estimates. Moreover, regulatory changes could increase our obligation to satisfy these or additional obligations. For our postretirement health care liability, assumed discount rates and health care cost trend rates have a significant effect on the expense and liability amounts reported for health care plans. Below we have provided two separate sensitivity analyses to demonstrate the significance of these assumptions in relation to reported amounts.

Health care cost trend rate:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	$ 6.6	$ (5.7)
Effect on total postretirement benefit obligation[1]	$ 79.7	$ (68.5)

Discount rate:

	One-Half Percentage-Point Increase	One-Half Percentage-Point Decrease
	(Dollars in millions)	
Effect on total service and interest cost components[1]	$ 0.8	$ (0.8)
Effect on total postretirement benefit obligation[1]	$ (39.1)	$ 41.1

(1) In addition to the effect on total service and interest cost components of expense, changes in trend and discount rates would also increase or decrease the actuarial gain or loss amortization expense component. The gain or loss amortization would approximate the increase or decrease in the obligation divided by 10.68 years at December 31, 2008.

Asset Retirement Obligations

Our asset retirement obligations primarily consist of spending estimates for surface land reclamation and support facilities at both surface and underground mines in accordance with federal and state reclamation laws in the U.S. and Australia as defined by each mining permit. Asset retirement obligations are determined for each mine using various estimates and assumptions including, among other items, estimates of disturbed acreage as determined from engineering data, estimates of future costs to reclaim the disturbed acreage and the timing of these cash flows, discounted using a credit-adjusted, risk-free rate. As changes in estimates occur (such as mine plan revisions, changes in estimated costs, or changes in timing of the reclamation activities), the obligation and asset are revised to reflect the new estimate after applying the appropriate credit-adjusted, risk-free rate. If our assumptions do not materialize as expected, actual cash expenditures and costs that we incur could be materially different than currently estimated. Moreover, regulatory changes could increase our obligation to perform reclamation and mine closing activities. Asset retirement obligation expense for the year ended December 31, 2008 was $48.2 million, and payments totaled $11.4 million. See Note 13 to our consolidated financial statements for additional details regarding our asset retirement obligations.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS No. 109), which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. In our annual evaluation of the need for a valuation allowance, we take into account various factors, including the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in our annual evaluation of our valuation allowance, we may record a change in valuation allowance through income tax expense in the period such determination is made.

Interpretation No. 48 (FIN No. 48) Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109) prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted this interpretation effective January 1, 2007. See Note 11 to our consolidated financial statements for additional details regarding the effect of income taxes.

Revenue Recognition

In general, we recognize revenues when they are realizable and earned. We generated 92% of our revenue in 2008 from the sale of coal to our customers. Revenue from coal sales is realized and earned when risk of loss passes to the customer. Under the typical terms of our coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that delivers coal to its destination.

With respect to other revenues, other operating income, or gains on asset sales recognized in situations unrelated to the shipment of coal, we carefully review the facts and circumstances of each transaction and apply the relevant accounting literature as appropriate, and do not recognize revenue until the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; the seller s price to the buyer is fixed or determinable; and collectibility is reasonably assured.

Trading Activities

We engage in the buying and selling of coal, freight and emissions allowances, both in over-the-counter markets and on exchanges. Under the provision of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, all derivative coal trading contracts are accounted for on a fair value (as defined by SFAS No. 157) basis, except those that qualify for and the Company has elected to apply a normal purchases and normal sales exception. For certain of our derivative coal trading contracts, we establish fair values using bid/ask price quotations obtained from multiple, independent third-party brokers to value coal, freight and emission allowance positions from the over-the-counter market. Prices from these sources are then averaged to obtain trading position values. We could experience difficulty in valuing our market positions if the number of third-party brokers should decrease or market liquidity is reduced. For our exchange-based positions, we utilize published settlement prices. Non-derivative coal contracts, including those that qualify for and the Company has elected to apply a normal purchases and normal sales exception, are accounted for on an accrual basis.

As of December 31, 2008, 94% of the contracts in our trading portfolio were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials. As of December 31, 2008, 75% of the estimated future value of our trading portfolio was scheduled to be realized by the end of 2009 and 88% within 24 months. See Note 3 and Note 5 to our consolidated financial statements for additional details regarding assets and liabilities from our coal trading activities.

Fair Value Measurements

We use various methods to determine the fair value of financial assets and liabilities using market-quoted inputs for valuation or corroboration as available. We utilize market data or assumptions that market participants would use in pricing the particular asset or liability, including assumptions about inherent risk. We primarily apply the market approach for recurring fair value measurements utilizing the best available information.

We consider credit and nonperformance risk in the fair value measurement by analyzing the counterparty s exposure balance, credit rating and average default rate, net of any counterparty credit enhancements (e.g., collateral), as well as our own credit rating for financial derivative liabilities.

We evaluate the quality and reliability of the assumptions and data used to measure fair value in the three hierarchy levels, Level 1, 2 and 3, as prescribed by SFAS No. 157 (see Note 3 and Note 5 to our consolidated financial statements for additional information). Commodity swaps and options and physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements, with limited price availability were classified in Level 3. Indicators of less liquid markets are those which our positions extend out to periods where there is low trade activity or where broker quotes reflect wide pricing spreads. Generally, these instruments or contracts are valued using internally generated models that include quotes from one to three reputable brokers where forward pricing curves are projected. Our valuation techniques also include basis adjustments for heat rate, sulfur and ash content, port and freight costs, and credit and nonperformance risk. We validate our valuation inputs with third-party information and settlement prices from other sources where available.

We have consistently applied these valuation techniques in all periods presented, and believe we have obtained the most accurate information available for the types of derivative contracts held. Valuation changes from period to period for each level will increase or decrease depending on: (i) the relative change in fair for positions held, (ii) new positions added, (iii) realized amounts for completed trades, and (iv) transfers between levels. Our coal trading strategies utilize various swaps and derivative physical contracts, which are categorized by level in the table below. Periodic changes in fair value for purchase and sale positions, which are executed to lock in coal trading spreads, occur in each level and therefore the overall change in value of our coal-trading platform requires consideration of valuation changes across all levels.

Net assets (liabilities) related to coal trading activities at December 31, 2008 and 2007 are as follows:

	December 31,		Increase
	2008	2007	(Decrease)
	(Dollars in millions)		

Level 1	$ (17.0)	$ 5.9	$ (22.9)
Level 2	337.8	(86.6)	424.4
Level 3	37.8	128.7	(90.9)
Total	$ 358.6	$ 48.0	$ 310.6

Our coal-trading platform includes positions designed to secure forward pricing for some of our production (i.e. cash flow hedges wherein the effective portion of the change in the fair value is recorded as a separate component of stockholders equity until the hedged transaction occurs) as well as positions designed to generate current period trading results. Overall pricing increases since December 31, 2007 and higher trading volumes, particularly from our international trading activities, have increased the value of our coal-trading portfolio during 2008. As a result, segment Adjusted EBITDA from our Trading and Brokerage segment totaled $218.9 million compared to $116.6 million in 2007. The fair value of coal trading positions designated as cash flow hedges of anticipated future sales was an asset of $220.4 million as of December 31, 2008 and a liability of $44.1 million as of December 31, 2007 (primarily classified as Level 2). The estimated realization of our aggregate coal trading portfolio of $358.6 million is 75% in 2009 and 88% within two years.

Level 3 Net Financial Asset (Liability) Detail

The Level 3 net financial assets (liabilities) as of December 31, 2008 are as follows:

		Net financial assets (liabilities) (Dollars in millions)
Physical commodity purchase/sale contracts coal trading activities	$	38.9
Commodity swaps and options coal trading activities		(1.1)
Total net Level 3 financial assets	$	37.8
Total net financial assets (liabilities) measured at fair value	$	(129.2)
Percent of Level 3 net financial assets to total net financial assets (liabilities) measured at fair value		Not meaningful[1]

(1) Percentage of Level 3 net financial assets compared to total net financial assets (liabilities) is not meaningful due to overall liability position as of December 31, 2008.

The following table summarizes the changes in our recurring Level 3 net financial assets:

		Year Ended December 31, 2008 (Dollars in millions)
Beginning of period	$	128.7
Total gains or losses (realized/unrealized):		
Included in earnings		(9.8)
Included in other comprehensive income		3.4
Purchases, issuances and settlements		(58.8)
Net transfers out		(25.7)

December 31, 2008	$	37.8

The following table summarizes the changes in unrealized gains (losses) relating to Level 3 net financial assets still held as January 1 and December 31, 2008:

	Year Ended December 31, 2008 (Dollars in millions)	
Changes in unrealized losses[1]	$	(34.8)

[1] For the periods presented, unrealized gains and losses from Level 3 items are offset by unrealized gains and losses on positions classified in Level 1 or 2, as well as other positions that have been realized during the applicable periods.

Exploration and Drilling Costs

Exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves.

Advance Stripping Costs

Pre-production: At existing surface operations, additional pits may be added to increase production capacity in order to meet customer requirements. These expansions may require significant capital to purchase additional equipment, expand the workforce, build or improve existing haul roads and create the initial pre-production box cut to remove overburden (i.e., advance stripping costs) for new pits at existing operations. If these pits operate in a separate and distinct area of the mine, the costs associated with initially uncovering coal (i.e., advance stripping costs incurred for the initial box cuts) for production are capitalized and amortized over the life of the developed pit consistent with coal industry practices.

Post-production: Advance stripping costs related to post-production are expensed as incurred. Where new pits are routinely developed as part of a contiguous mining sequence, we expense such costs as incurred. The development of a contiguous pit typically reflects the planned progression of an existing pit, thus maintaining production levels from the same mining area utilizing the same employee group and equipment.

Share-Based Compensation

We account for share-based compensation in accordance with the fair value recognition provisions of SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123(R)), which we adopted using the modified prospective option on January 1, 2006. Under SFAS No. 123(R), share-based compensation expense is generally measured at the grant date and recognized as expense over the vesting period of the award. We utilize restricted stock, nonqualified stock options, performance units, deferred stock units and an employee stock purchase plan as part of our share-based compensation program. Determining fair value requires us to make a number of assumptions, including items such as expected term, risk-free rate, forfeiture rate and expected volatility. The assumptions used in calculating the fair value of share-based awards represent our best estimates, but these estimates involve inherent uncertainties and the application of management judgment. Although we believe the assumptions and estimates we have made are reasonable and appropriate, changes in assumptions could materially impact our reported financial results.

Liquidity and Capital Resources

Our primary sources of cash include sales of our coal production to customers, cash generated from our trading and brokerage activities, sales of non-core assets and financing transactions, including the sale of our accounts receivable (through our securitization program). Our primary uses of cash include our cash costs of coal production, capital expenditures, federal coal lease payments, interest costs and costs related to past mining obligations as well as acquisitions. Our ability to pay dividends, service our debt (interest and principal) and acquire new productive assets or businesses is dependent upon our ability to continue to generate cash from the primary sources noted above in excess of the primary uses. Future dividends and share repurchases, among other restricted items, are subject to limitations imposed in the covenants of our 5.875% and 6.875% Senior Notes and Debentures. We generally fund all of our capital expenditure requirements with cash generated from operations.

We believe our available borrowing capicity and operating cash flows will be sufficient in the near term. As of December 31, 2008, we had $1.5 billion of available borrowing capacity under our Senior Unsecured Credit Facility, net of outstanding letters of credit. The Senior Unsecured Credit Facility matures on September 15, 2011.

Our two defined benefit pension plans, which have approximately 45% of their assets invested in equity securities, experienced negative returns in 2008 due to recent equity market performance. The Pension Protection Act of 2006 (the Pension Protection Act), which was effective January 1, 2008, increased the long-term funding targets for single employer pension plans from 90% to 100%. In addition, the Pension Protection

Act restricts at risk (generally defined as under 80% funded) plans from making lump sum payments and increasing benefits unless they are funded immediately, and also requires that the plan give participants notice regarding the at-risk status of the plan. If a plan falls below 60%, lump sum payments are prohibited and participant benefit accruals cease.

As of December 31, 2008, our pension plans were approximately 68% funded, before considering planned 2009 contributions. Our minimum funding requirement for 2009 is approximately $25 million, and would result in a funded status above 70%.

Net cash provided by operating activities from continuing operations for 2008 increased $956.1 million compared to the prior year. The increase was primarily related to a current year increase in operating cash flows generated from our Australian mining operations and the timing of cash flows for working capital driven by an increase in income tax amounts that will be payable in future periods.

Net cash used in investing activities from continuing operations decreased $7.4 million in 2008 compared to the prior year. The decrease primarily reflects lower capital spending of $160.5 million in 2008, mostly offset by the acquisition of minority interests of $110.1 million relating to our Millennium Mine, and a decrease in cash proceeds of $46.8 million, net of notes receivable, related to asset disposals.

Net cash used in financing activities reflects a use of $375.8 million in 2008 compared to $44.7 million of cash provided by financing activities in 2007. The increase in the use of cash in 2008 is primarily due to the repurchase of $199.8 million of our outstanding common stock, $97.7 million to repay the borrowings on our Revolving Credit Facility, and debt repayments of $32.7 million, including payments of $18.8 million on our Term Loan under the Senior Unsecured Credit Facility. During 2007, we repaid $37.9 million of our Term Loan and purchased in the open market $13.8 million face value of our 5.875% Senior Notes due 2016. We also made the final principal payment of $59.5 million on our 5% Subordinated Note. Our Revolving Credit Facility balance increased $97.7 million in 2007 as it was utilized to fund cash contributions to Patriot at the spin-off date.

Our total indebtedness as of December 31, 2008 and 2007 consisted of the following:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Term Loan under Senior Unsecured Credit Facility	$ 490.3	$ 509.1
Revolving Credit Facility		97.7
Convertible Junior Subordinated Debentures due 2066	732.5	732.5
7.375% Senior Notes due 2016	650.0	650.0
6.875% Senior Notes due 2013	650.0	650.0
7.875% Senior Notes due 2026	247.0	247.0
5.875% Senior Notes due 2016	218.1	218.1
6.84% Series C Bonds due 2016	43.0	43.0
6.34% Series B Bonds due 2014	18.0	21.0
6.84% Series A Bonds due 2014	10.0	10.0
Capital lease obligations	81.2	92.2
Fair value hedge adjustment	15.1	1.6
Other	1.0	0.9

Total	$ 3,156.2	$ 3,273.1

We were in compliance with all of the covenants of the Senior Unsecured Credit Facility, the 6.875% Senior Notes, the 5.875% Senior Notes, the 7.375% Senior Notes, the 7.875% Senior Notes and the Debentures as of December 31, 2008.

Senior Unsecured Credit Facility

In September 2006, we entered into a Third Amended and Restated Credit Agreement, which established a $2.75 billion Senior Unsecured Credit Facility and which amended and restated in full our then existing $1.35 billion Senior Secured Credit Facility. The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility and a $950.0 million Term Loan Facility. The Revolving Credit Facility is intended to accommodate working capital needs, letters of credit, the funding of capital expenditures and other general corporate purposes. The Revolving Credit Facility also includes a $50.0 million sub-facility available for same-day swingline loan borrowings.

Loans under the facility are available in U.S. dollars, with a sub-facility under the Revolving Credit Facility available in Australian dollars, pounds sterling and euros. Letters of credit under the Revolving Credit Facility are available to us in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and euros. The interest rate payable on the Revolving Credit Facility and the Term Loan Facility under the Senior Unsecured Credit Facility is based on a pricing grid tied to our leverage ratio, as defined in the Third Amended and Restated Credit Agreement. Currently, the interest rate payable on the Revolving Credit Facility and the Term Loan Facility is LIBOR plus 0.75%, which at December 31, 2008 was 2.2%.

Under the Senior Unsecured Credit Facility, we must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined in the Third Amended and Restated Credit Agreement. The financial covenants also place limitations on our investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties, and the imposition of liens on our assets. The new facility is less restrictive with respect to limitations on our dividend payments, capital expenditures, asset sales or stock repurchases. The Senior Unsecured Credit Facility matures on September 15, 2011.

As of December 31, 2008, we had no borrowings and $245.1 million letters of credit outstanding under our Revolving Credit Facility. Our Revolving Credit Facility is primarily used for standby letters of credit and short-term working capital needs. The remaining available borrowing capacity ($1.5 billion as of December 31, 2008) can be used to fund strategic acquisitions or meet other financing needs, including additional standby letters of credit.

Other Long-Term Debt

A description of our other debt instruments is described in Note 12 to the consolidated financial statements in Part IV, Item 15 of this report.

Third-party Security Ratings

The ratings for our Senior Unsecured Credit Facility and our Senior Unsecured Notes are as follows: Moody s has issued a Ba1 rating, Standard & Poor s a BB+ rating, and Fitch has issued a BB+ rating. The ratings on our Convertible Junior Subordinated Debentures are as follows: Moody s has issued a Ba3 rating, Standard & Poor s a B+ rating, and Fitch has issued a BB- rating. These security ratings reflected the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Shelf Registration Statement

On July 28, 2006, we filed an automatic shelf registration statement on Form S-3 as a well-known seasoned issuer with the SEC. The registration was for an indeterminate number of securities and is effective for three years, at which time we expect to be able to file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, we have the capacity to offer and sell from time to time securities, including common stock, preferred stock, debt securities, warrants and units. The Debentures, 7.375% Senior Notes due 2016 and 7.875% Senior Notes due 2026 were issued pursuant to the shelf registration statement.

Share Repurchase Program

In July 2005, our Board of Directors authorized a share repurchase program of up to 5% of the then outstanding shares of our common stock, approximately 13 million shares. The repurchases may be made from time to time based on an evaluation of our outlook and general business conditions, as well as alternative investment and debt repayment options. In addition, our Board of Directors had previously authorized our Chairman and Chief Executive Officer to repurchase up to $100 million of our common stock outside the repurchase program. In October 2008, our Board of Directors amended the share repurchase program to increase the total authorized amount to $1 billion. The amended repurchase program does not have an expiration date and may be discontinued at any time. In 2008, we repurchased 5.5 million of our common shares for $199.8 million under this repurchase program and in 2006, we repurchased 2.2 million of our common shares for $99.8 million under this repurchase program.

Contractual Obligations

The following is a summary of our contractual obligations as of December 31, 2008:

	Payments Due By Year				
	Total	Less than 1 Year	2 - 3 Years	4 - 5 Years	More than 5 Years
	(Dollars in millions)				
Long-term debt obligations (principal and interest)	$ 5,356.1	$ 198.5	$ 861.8	$ 1,004.1	$ 3,291.8
Capital lease obligations (principal and interest)	99.4	19.1	30.2	38.1	12.0
Operating lease obligations	409.2	76.3	132.5	73.6	126.8
Unconditional purchase obligations(1)	38.5	38.5			
Coal reserve lease and royalty obligations	193.9	134.1	15.1	11.5	33.2
Other long-term liabilities(2)	1,513.1	192.7	216.5	178.2	925.7
Total contractual cash obligations	$ 7,610.2	$ 659.2	$ 1,256.1	$ 1,305.5	$ 4,389.5

(1) We have purchase agreements with approved vendors for most types of operating expenses. However, our specific open purchase orders (which have not been recognized as a liability) under these purchase agreements, combined with any other open purchase orders, are not material. The commitments in the table above relate to significant capital purchases.

(2) Represents long-term liabilities relating to our postretirement benefit plans, work-related injuries and illnesses, defined benefit pension plans and mine reclamation and end of mine closure costs.

As of December 31, 2008, we had $38.5 million of purchase obligations for capital expenditures and $124.6 million of obligations related to federal coal reserve lease payments due over the next five years. The purchase obligations for capital expenditures primarily relate to the replacement and improvement of equipment and facilities at existing mines. We expect to fund capital expenditures primarily through operating cash flow.

We do not expect any of the $186.3 million of gross unrecognized tax benefits reported in our consolidated financial statements to require cash settlement within the next year. Beyond that, we are unable to make reasonably reliable estimates of periodic cash settlements with respect to such unrecognized tax benefits.

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 and our accounts receivable securitization. Liabilities related to these arrangements are not reflected in our consolidated balance sheets, and we do not expect any material adverse effects on our financial condition, results of operations or cash flows to result from these off-balance sheet arrangements.

We use a combination of surety bonds, corporate guarantees (such as self bonds) and letters of credit to secure our financial obligations for reclamation, workers compensation, and coal lease obligations as follows as of December 31, 2008:

	Reclamation Obligations	Lease Obligations	Workers Compensation Obligations	Other(1)	Total
			(Dollars in millions)		
Self Bonding	$ 773.4	$	$	$	$ 773.4
Surety Bonds	740.6	99.2	19.3	15.2	874.3
Letters of Credit	0.1		54.9	199.3	254.3
	$ 1,514.1	$ 99.2	$ 74.2	$ 214.5	$ 1,902.0

(1) Other includes the four letter of credit obligations described below and an additional $24.3 million in self-bonding, letters of credit and surety bonds related to collateral for surety companies, road maintenance, performance guarantees and other operations.

We own a 37.5% interest in a partnership that leases a coal export terminal from the Peninsula Ports Authority of Virginia under a 30-year lease that permits the partnership to purchase the terminal at the end of the lease term for a nominal amount. The partners have severally (but not jointly) agreed to make payments under various agreements which in the aggregate provide the partnership with sufficient funds to pay rents and to cover the principal and interest payments on the floating-rate industrial revenue bonds issued by the Peninsula Ports Authority, and which are supported by letters of credit from a commercial bank. As of December 31, 2008, our maximum reimbursement obligation to the commercial bank was in turn supported by two letters of credit totaling $42.8 million.

We are party to an agreement with the PBGC and TXU Europe Limited, an affiliate of our former parent corporation, under which we are required to make special contributions to two of our defined benefit pension plans and to maintain a $37.0 million letter of credit in favor of the PBGC. If we or the PBGC give notice of an intent to terminate one or more of the covered pension plans in which liabilities are not fully funded, or if we fail to maintain the letter of credit, the PBGC may draw down on the letter of credit and use the proceeds to satisfy liabilities under the Employee Retirement Income Security Act of 1974, as amended. The PBGC, however, is required to first apply amounts received from a $110.0 million guarantee in place from TXU Europe Limited in favor of the PBGC before it draws on our letter of credit. On November 19, 2002 TXU Europe Limited was placed under the administration process in the United Kingdom (a process similar to bankruptcy proceedings in the U.S.) and continues under this process as of December 31, 2008. As a result of these proceedings, TXU Europe Limited may be liquidated or otherwise reorganized in such a way as to relieve it of its obligations under its guarantee.

At December 31, 2008, we have a $110.4 million letter of credit for collateral for bank guarantees issued with respect to certain reclamation and performance obligations related to the mines acquired in the Excel acquisition.

Other Guarantees

As part of arrangements through which we obtain exclusive sales representation agreements with small coal mining companies (the Counterparties), we issued financial guarantees on behalf of the Counterparties. These guarantees facilitate the Counterparties efforts to obtain bonding or financing. In the event of default, we have multiple recourse options, including the ability to assume the loans and procure title and use of the equipment purchased through the loans. If default occurs, we have the ability and intent to exercise our recourse options, so the liability associated with the guarantee has been valued at zero. The aggregate amount guaranteed by us for all such Counterparties was $10.0 million at December 31, 2008. Our obligations under the guarantees extend to September 2013.

As part of the Patriot spin-off, we agreed to maintain several letters of credit that secured Patriot obligations for certain employee benefits and workers compensation obligations. These letters of credit are to be released upon Patriot satisfying the beneficiaries with alternate letters of credit or insurance. If Patriot is unable to satisfy the primary beneficiaries by June 30, 2011, they are then required to provide directly to us a letter of credit in the amount of the remaining obligation. The amount of letters of credit maintained by us securing Patriot obligations was $7.0 million at December 31, 2008 and $136.8 million at December 31, 2007.

Under our accounts receivable securitization program, undivided interests in a pool of eligible trade receivables contributed to our wholly-owned, bankruptcy-remote subsidiary are sold, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated commercial paper. We utilize proceeds from the sale of our accounts receivable as an alternative to other forms of debt, effectively reducing our overall borrowing costs. The funding cost of the securitization program was $10.8 million for the year ended December 31, 2008 and $11.2 million for the year ended December 31, 2007. The securitization program and the underlying facilities will effectively expire in May 2009. The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $275.0 million as of December 31, 2008 and December 31, 2007 (see Note 6 to our consolidated financial statements for additional information on accounts receivable securitization).

Newly Adopted Accounting Pronouncements and Accounting Pronouncements Not Yet Implemented

See Note 1 to the consolidated financial statements in Part IV, Item 15 of this report for a discussion of newly adopted accounting pronouncements and accounting pronouncements not yet implemented.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

The potential for changes in the market value of our coal and freight trading, emission allowances, crude oil, diesel fuel, natural gas, explosives, interest rate and currency portfolios is referred to as market risk. Market risk related to our coal trading and freight portfolio is evaluated using a value at risk analysis (described below). Value at risk analysis is not used to evaluate our non-trading interest rate, diesel fuel, explosives or currency hedging portfolios. A description of each market risk category is set forth below. We attempt to manage market risks through diversification, controlling position sizes and executing hedging strategies. Due to lack of quoted market prices and the long-term, illiquid nature of the positions, we have not quantified market risk related to our non-trading, long-term coal supply agreement portfolio.

Coal Trading Activities and Related Commodity Price Risk

We engage in over-the-counter and direct trading of coal and ocean freight. These activities give rise to commodity price risk, which represents the potential loss that can be caused by an adverse change in the market value of a particular commitment. We actively measure, monitor and adjust traded position levels to remain within risk limits prescribed by management. For example, we have policies in place that limit the amount of total exposure, in value at risk terms, that we may assume at any point in time.

We account for coal trading using the fair value method, which requires us to reflect financial instruments with third parties, such as forwards, options and swaps, at market value in our consolidated financial statements. Our trading portfolio included forwards and swaps as of December 31, 2008 and December 31, 2007.

We perform a value at risk analysis on our coal trading portfolio, which includes over-the-counter and brokerage trading of coal. The use of value at risk allows us to quantify in dollars, on a daily basis, the price risk inherent in our trading portfolio. Value at risk represents the potential loss in value of our mark-to-market portfolio due to adverse market movements over a defined time horizon (liquidation period) within a specified confidence level. Our value at risk model is based on the industry standard variance/co-variance approach. This captures our exposure related to option, swap and forward positions. Our value at risk model assumes a 5 to 15-day holding period and a 95% one-tailed confidence interval. This means that there is a one in 20 statistical chance that the portfolio would lose more than the value at risk estimates during the liquidation period. During 2008, we implemented a change to our volatility calculation by incorporating an exponentially weighted moving average algorithm based on the previous 60 market days. This algorithm makes our volatility more representative of recent market conditions, while still reflecting an awareness of historical price movements.

The use of value at risk allows management to aggregate pricing risks across products in the portfolio, compare risk on a consistent basis and identify the drivers of risk. Due to the subjectivity in the choice of the liquidation period, reliance on historical data to calibrate the models and the inherent limitations in the value at risk methodology, we perform regular stress and scenario analysis to estimate the impacts of market changes on the value of the portfolio. Additionally, back-testing is regularly performed to monitor the effectiveness of our value at risk measure. The results of these analyses are used to supplement the value at risk methodology and identify additional market-related risks.

We use historical data to estimate price volatility as an input to value at risk and to better reflect current asset and liability volatilities. Given our reliance on historical data, we believe value at risk is effective in estimating risk exposures in markets in which there are not sudden fundamental changes or shifts in market conditions. An inherent limitation of value at risk is that past changes in market risk factors may not produce accurate predictions of future market risk. Value at risk should be evaluated in light of this limitation.

During the year ended December 31, 2008, the combined actual low, high, and average values at risk for our coal trading portfolio were $8.5 million, $27.2 million, and $19.1 million, respectively. Our value at risk increased over the prior year due to greater price volatility in the eastern U.S. and international coal markets.

As of December 31, 2008, the timing of the estimated future realization of the value of our trading portfolio was as follows:

Year of Expiration	**Percentage of Portfolio**
2009	75%
2010	13%
2011	11%
2012	1%
	100%

We also monitor other types of risk associated with our coal trading activities, including credit, market liquidity and counterparty nonperformance.

Performance and Credit Risk

Our concentration of performance and credit risk is substantially with electric utilities, energy producers and energy marketers. Our policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to regularly monitor the credit extended. If we engage in a transaction with a counterparty that does not meet our credit standards, we seek to protect our position by requiring the counterparty to provide an appropriate credit enhancement. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of a failure to pay. In general, increases in coal price volatility and our own trading activity resulted in greater exposure to our coal-trading counterparties during 2008.

In addition to credit risk, performance risk includes the possibility that a counterparty fails to deliver agreed production or trading volumes. When appropriate (as determined by our credit management function), we have taken steps to reduce our exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include

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obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for our benefit to serve as collateral in the event of failure to pay. To reduce our credit exposure related to trading and brokerage activities, we seek to enter into agreements that include netting language with counterparties that permit us to offset trading positions, receivables, and payables with such counterparties.

We conduct our various hedging activities related to foreign currency, interest rate management, and fuel and explosives exposures with a variety of highly-rated commercial banks. In light of the recent turmoil in the financial markets we continue to closely monitor counterparty creditworthiness.

Foreign Currency Risk

We utilize currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures. Our currency hedging program for 2009 targets hedging approximately 70% of our anticipated Australian dollar-denominated operating expenditures. The accounting for these derivatives is discussed in Note 3 to our consolidated financial statements. Assuming we had no hedges in place, our exposure in operating costs and expenses due to a five-cent change in the Australian dollar/U.S. dollar exchange rate is approximately $84.0 million for 2009. However, taking into consideration hedges currently in place, our net exposure to the same rate change is approximately $25.9 million for 2009. The chart at the end of Item 7A. shows the notional amount of our forward contracts as of December 31, 2008.

Interest Rate Risk

Our objectives in managing exposure to interest rate changes are to limit the impact of interest rate changes on earnings and cash flows and to lower overall borrowing costs. To achieve these objectives, we manage fixed-rate debt as a percent of net debt through the use of various hedging instruments, which are discussed in detail in Note 12 to our consolidated financial statements. As of December 31, 2008, after taking into consideration the effects of interest rate swaps, we had $2.5 billion of fixed-rate borrowings and $691.2 million of variable-rate borrowings outstanding. A one percentage point increase in interest rates would result in an annualized increase to interest expense of $6.9 million on our variable-rate borrowings. With respect to our fixed-rate borrowings, a one percentage point increase in interest rates would result in a $145.2 million decrease in the estimated fair value of these borrowings.

Other Non-trading Activities Commodity Price Risk

Long-term Coal Contracts

We manage our commodity price risk for our non-trading, long-term coal contract portfolio through the use of long-term coal supply agreements, rather than through the use of derivative instruments. We sold 90% and 87% of our worldwide sales volume under long-term coal supply agreements during 2008 and 2007, respectively. As of January 27, 2009, we have largely sold out expected 2009 U.S. production. We had 9 to 11 million tons remaining to be priced for 2009 in Australia at January 27, 2009.

Diesel Fuel and Explosives Hedges

Some of the products used in our mining activities, such as diesel fuel and explosives, are subject to commodity price risk. To manage this risk, we use a combination of forward contracts with our suppliers and financial derivative contracts, which are primarily swap contracts with financial institutions. As of December 31, 2008, we had derivative contracts outstanding that are designated as cash flow hedges of anticipated purchases of fuel and explosives.

Notional amounts outstanding under fuel-related, derivative swap contracts are noted in the chart at the end of Item 7A. We expect to consume 125 to 130 million gallons of fuel next year. A $10 dollar per barrel change in the price of crude oil (the primary component of a refined diesel fuel product) would increase or decrease our annual fuel costs (ignoring the effects of hedging) by approximately $31 million.

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Notional amounts outstanding under explosives-related swap contracts are noted in the chart below. We expect to consume 335,000 to 345,000 tons of explosives per year in the U.S. Explosives costs in Australia are generally included with the fees paid to our contract miners. Based on our expected usage, a price change in natural gas (often a key component in the production of explosives) of one dollar per million MMBtu (ignoring the effects of hedging) would result in an increase or decrease in our annual explosives costs of approximately $7 million.

	Notional Amount by term to maturity							Account Classification by		
	Total	2009	2010	2011	2012	2013	2014 and thereafter	Cash flow hedge	Fair value hedge	Fair Value asset (liabilit
erest Rate Swaps										
ed-to-floating llars in millions)	$ 320.0	$	$	$	$	$ 220.0	$ 100.0	$	$ 320.0	$ 12.
ating-to-fixed llars in millions)	$ 186.0	$	$	$ 120.0	$	$	$ 66.0	$ 186.0	$	$ (21.
reign Currency										
:US$ forwards and ions (A$ millions)	2,408.0	1,161.7	826.3	420.0				2,408.0		(283.
mmodity Contracts										
esel fuel hedge itracts (million lons)	189.4	98.4	64.4	26.6				189.4		(176.
S. explosives hedge itracts (million IBtu)	6.5	3.6	2.9					6.5		(18.

Item 8. ***Financial Statements and Supplementary Data.***

See Part IV, Item 15 of this report for information required by this Item, which information is incorporated by reference herein.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

Our disclosure controls and procedures are designed to, among other things, provide reasonable assurance that material information, both financial and non-financial, and other information required under the securities laws to be disclosed is accumulated and communicated to senior management, including the principal executive officer and principal financial officer, on a timely basis. As of December 31, 2008, the end of the period covered by this Annual Report on Form 10-K, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of December 31, 2008, and concluded that such controls and procedures are effective to provide reasonable assurance that the desired control objectives were achieved.

Changes in Internal Control Over Financial Reporting

We periodically review our internal control over financial reporting as part of our efforts to ensure compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. In addition, we routinely review our system of internal control over financial reporting to identify potential changes to our processes and systems that may improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new systems, consolidating the activities of acquired business units, migrating certain processes to our shared services organizations, formalizing and refining policies and procedures, improving segregation of duties, and adding monitoring controls. In addition, when we acquire new businesses, we incorporate our controls and procedures into the acquired business as part of our integration activities. There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Management s Report on Internal Control Over Financial Reporting

Management is responsible for maintaining and establishing adequate internal control over financial reporting. Our internal control framework and processes were designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

Management conducted an assessment of the effectiveness of our internal control over financial reporting using the criteria set by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on this assessment, management concluded that the Company s internal control over financial reporting were effective to provide reasonable assurance that the desired control objectives were achieved as of December 31, 2008.

Our Independent Registered Public Accounting Firm, Ernst & Young LLP, has audited our internal control over financial reporting, as stated in their unqualified opinion report included herein.

/s/ GREGORY H. BOYCE	/s/ MICHAEL C. CREWS
Gregory H. Boyce Chairman and Chief Executive Officer	Michael C. Crews Executive Vice President and Chief Financial Officer

February 27, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited Peabody Energy Corporation s (the Company s) internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Peabody Energy Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Peabody Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Peabody Energy Corporation as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008, and our report dated February 26, 2009, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri

February 26, 2009

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information required by Item 401 of Regulation S-K is included under the caption Election of Directors in our 2009 Proxy Statement and in Part I of this report under the caption Executive Officers of the Company. The information required by Items 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K is included under the captions Ownership of Company Securities Section 16(a) Beneficial Ownership Reporting Compliance, Corporate Governance Matters and Information Regarding Board of Directors and Committees in our 2009 Proxy Statement. Such information is incorporated herein by reference.

Item 11. ***Executive Compensation.***

The information required by Items 402 and 407 (e)(4) and (e)(5) of Regulation S-K is included under the captions Executive Compensation, Compensation Committee Interlocks and Insider Participation and Report of the Compensation Committee in our 2009 Proxy Statement and is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The information required by Items 201(d) and 403 of Regulation S-K is included under the captions Equity Compensation Plan Information and Ownership of Company Securities in our 2009 Proxy Statement and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by Items 404 and 407(a) of Regulation S-K is included under the captions Policy for Approval of Related Person Transactions and Information Regarding Board of Directors and Committees in our 2009 Proxy Statement and is incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services.***

The information required by Item 9(e) of Schedule 14A is included under the caption Appointment of Independent Registered Public Accounting Firm and Fees in our 2009 Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(a) Documents Filed as Part of the Report

(1) Financial Statements.

The following consolidated financial statements of Peabody Energy Corporation are included herein on the pages indicated:

(2) Financial Statement Schedule.

The following financial statement schedule of Peabody Energy Corporation and the report thereon of the independent registered public accounting firm are at the pages indicated:

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable and, therefore, have been omitted.

(3) Exhibits.

See Exhibit Index hereto.

Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the Company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the Company and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Securities and Exchange Commission upon request.

SIGNATURES

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

PEABODY ENERGY CORPORATION

/s/ GREGORY H. BOYCE
Gregory H. Boyce
Chairman and Chief Executive Officer

Date: February 27, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons, on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ GREGORY H. BOYCE Gregory H. Boyce	Chairman and Chief Executive Officer, Director (principal executive officer)	February 27, 2009
/s/ MICHAEL C. CREWS Michael C. Crews	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2009
/s/ WILLIAM A. COLEY William A. Coley	Director	February 27, 2009
/s/ WILLIAM E. JAMES William E. James	Director	February 27, 2009
/s/ ROBERT B. KARN III Robert B. Karn III	Director	February 27, 2009
/s/ HENRY E. LENTZ Henry E. Lentz	Director	February 27, 2009
/s/ WILLIAM C. RUSNACK William C. Rusnack	Director	February 27, 2009
/s/ BLANCHE M. TOUHILL, PHD	Director	February 27, 2009

Blanche M. Touhill, PhD		
/s/ JOHN F. TURNER	Director	February 27, 2009
John F. Turner		
/s/ SANDRA VAN TREASE	Director	February 27, 2009
Sandra Van Trease		
/s/ ALAN H. WASHKOWITZ	Director	February 27, 2009
Alan H. Washkowitz		

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Peabody Energy Corporation

We have audited the accompanying consolidated balance sheets of Peabody Energy Corporation (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Peabody Energy Corporation at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2008, the Company changed its method of accounting for the recognition of derivative positions with the same counterparty, on January 1, 2007, the Company changed its method of accounting for uncertain tax positions, on December 31, 2006, the Company changed its method for accounting for defined pension benefit and other postretirement plans, and on January 1, 2006, the Company change its method of accounting for stripping costs.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Peabody Energy Corporation s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 26, 2009, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

St. Louis, Missouri
February 26, 2009

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PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(Dollars in millions, except share and per share data)		
Revenues			
Sales	$ 6,036.3	$ 4,335.1	$ 3,944.9
Other revenues	557.1	210.0	106.0
Total revenues	6,593.4	4,545.1	4,050.9
Costs and Expenses			
Operating costs and expenses	4,617.2	3,532.5	3,088.2
Depreciation, depletion and amortization	406.2	352.2	284.2
Asset retirement obligation expense	48.2	23.7	14.2
Selling and administrative expenses	201.8	147.1	128.0
Other operating income:			
Net gain on disposal or exchange of assets	(72.9)	(88.6)	(53.5)
Income from equity affiliates		(14.5)	(22.8)
Operating Profit	1,392.9	592.7	612.6
Interest expense	226.2	235.0	139.1
Interest income	(10.1)	(7.1)	(11.3)
Income From Continuing Operations Before Income Taxes and Minority Interests	1,176.8	364.8	484.8
Income tax provision (benefit)	185.8	(72.9)	(85.7)
Minority interests	6.2	(2.3)	0.6
Income From Continuing Operations	984.8	440.0	569.9
Income (loss) from discontinued operations, net of tax	(31.3)	(175.7)	30.8
Net Income	$ 953.5	$ 264.3	$ 600.7
Basic Earnings Per Share			
Income from continuing operations	$ 3.66	$ 1.67	$ 2.16
Income (loss) from discontinued operations	(0.11)	(0.67)	0.12
Net income	$ 3.55	$ 1.00	$ 2.28
Weighted Average Shares Outstanding - Basic	268,860,528	264,068,180	263,419,344
Diluted Earnings Per Share			
Income from continuing operations	$ 3.63	$ 1.63	$ 2.12

Income (loss) from discontinued operations		(0.12)		(0.65)		0.11
Net income	$	3.51	$	0.98	$	2.23
Weighted Average Shares Outstanding - Diluted		271,275,849		269,166,290		269,166,005
Dividends Declared Per Share	$	0.24	$	0.24	$	0.24

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(Dollars in millions, except share and per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 449.7	$ 45.3
Accounts receivable, net of allowance for doubtful accounts of $24.8 and $11.9 at December 31, 2008 and 2007, respectively	383.6	256.9
Inventories	277.7	264.7
Assets from coal trading activities, net	662.8	349.8
Deferred income taxes	1.7	58.8
Other current assets	195.8	335.0
Total current assets	1,971.3	1,310.5
Property, plant, equipment and mine development mine development		
Land and coal interests	7,354.7	7,175.4
Buildings and improvements	861.3	658.1
Machinery and equipment	1,265.8	1,256.2
Less accumulated depreciation, depletion and amortization	(2,166.6)	(1,791.8)
Property, plant, equipment and mine development, net	7,315.2	7,297.9
Deferred income taxes	118.4	
Investments and other assets	417.5	482.8
Total assets	$ 9,822.4	$ 9,091.2
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 17.0	$ 134.4
Liabilities from coal trading activities, net	304.2	301.8
Accounts payable and accrued expenses	1,535.0	1,134.0
Total current liabilities	1,856.2	1,570.2
Long-term debt, less current maturities	3,139.2	3,138.7
Deferred income taxes		354.8
Asset retirement obligations	422.6	362.8
Accrued postretirement benefit costs	766.1	785.7
Other noncurrent liabilities	733.1	358.6

Total liabilities	6,917.2	6,570.8
Minority interests	1.4	0.7
Stockholders equity		
Preferred Stock $0.01 per share par value; 10,000,000 shares authorized, no shares issued or outstanding as of December 31, 2008 or 2007		
Series A Junior Participating Preferred Stock 1,500,000 shares authorized, no shares issued or outstanding as of December 31, 2008 or 2007		
Perpetual Preferred Stock 750,000 shares authorized, no shares issued or outstanding as of December 31, 2008 or 2007		
Series Common Stock $0.01 per share par value; 40,000,000 shares authorized, no shares issued or outstanding as of December 31, 2008 or 2007		
Common Stock $0.01 per share par value; 800,000,000 shares authorized, 275,211,240 shares issued and 266,644,979 shares outstanding as of December 31, 2008 and 800,000,000 shares authorized, 272,911,564 shares issued and 270,066,621 shares outstanding as of December 31, 2007	2.8	2.7
Additional paid-in capital	1,804.8	1,750.7
Retained earnings	1,803.5	941.4
Accumulated other comprehensive loss	(388.5)	(67.1)
Treasury shares, at cost: 8,566,261 shares as of December 31, 2008 and 2,844,943 shares as of December 31, 2007	(318.8)	(108.0)
Total stockholders equity	2,903.8	2,519.7
Total liabilities and stockholders equity	$ 9,822.4	$ 9,091.2

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
	(Dollars in millions)		
Cash Flows From Operating Activities			
Net income	$ 953.5	$ 264.3	$ 600.7
(Income) loss from discontinued operations	31.3	175.7	(30.8)
Income from continuing operations	984.8	440.0	569.9
Adjustments to reconcile income from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	406.2	352.2	284.2
Deferred income taxes	(32.9)	(196.2)	(191.2)
Amortization of debt discount and debt issuance costs	6.7	7.2	7.4
Net gain on disposal or exchange of assets	(72.9)	(88.6)	(53.5)
Income from equity affiliates		(14.5)	(22.8)
Revenue recovery on coal supply agreements	(56.9)		
Minority interest expense (income)	6.2	(2.3)	0.6
Stock compensation expense	34.9	20.1	17.1
Dividends received from equity affiliates	19.9	12.9	18.1
Changes in current assets and liabilities, net of acquisitions:			
Accounts receivable, including securitization	(113.5)	65.2	(110.5)
Inventories	(13.0)	(62.2)	(27.3)
Net assets from coal trading activities	(43.0)	(77.6)	(9.0)
Other current assets	1.7	(57.1)	(20.3)
Accounts payable and accrued expenses	225.5	53.6	103.8
Asset retirement obligations	32.9	13.6	(3.1)
Workers compensation obligations	10.3	2.7	(0.1)
Accrued postretirement benefit costs	13.6	13.1	59.1
Contributions to pension plans	(21.3)	(5.4)	(6.1)
Other, net	24.7	(18.9)	(9.7)
Net cash provided by continuing operations	1,413.9	457.8	606.6
Net cash used in discontinued operations	(128.2)	(141.4)	(23.3)
Net cash provided by operating activities	1,285.7	316.4	583.3
Cash Flows From Investing Activities			
Acquisition of Excel Coal Limited, net of cash acquired			(1,507.8)
Acquisitions of minority interests	(110.1)		
Additions to property, plant, equipment and mine development	(266.2)	(438.8)	(391.9)
Federal coal lease expenditures	(178.5)	(178.2)	(178.2)

Investment in Prairie State	(40.9)	(28.8)	
Proceeds from disposal of assets, net of notes receivable	72.8	119.6	29.4
Additions to advance mining royalties	(6.0)	(8.1)	(5.0)
Investments in equity affiliates and joint ventures	(2.6)	(4.6)	(2.1)
Net cash used in continuing operations	(531.5)	(538.9)	(2,055.6)
Net cash provided by (used in) discontinued operations	26.0	(36.4)	(88.2)
Net cash used in investing activities	(505.5)	(575.3)	(2,143.8)
Cash Flows From Financing Activities			
Change in revolving line of credit	(97.7)	97.7	
Proceeds from long-term debt			2,604.1
Payments of long-term debt	(32.7)	(117.8)	(1,046.0)
Common stock repurchase	(199.8)		(99.8)
Dividends paid	(64.9)	(63.7)	(63.5)
Payment of debt issuance costs		(0.8)	(40.6)
Excess tax benefit related to stock options exercised		96.7	33.2
Proceeds from stock options exercised	14.1	26.2	15.6
Proceeds from employee stock purchases	5.2	6.4	4.5
Net cash provided by (used in) continuing operations	(375.8)	44.7	1,407.5
Net cash used in discontinued operations		(67.0)	(23.8)
Net cash provided by (used in) financing activities	(375.8)	(22.3)	1,383.7
Net increase (decrease) in cash and cash equivalents	404.4	(281.2)	(176.8)
Cash and cash equivalents at beginning of year	45.3	326.5	503.3
Cash and cash equivalents at end of year	$ 449.7	$ 45.3	$ 326.5

See accompanying notes to consolidated financial statements

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PEABODY ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Treasury Stock	Total Stockholders Equity
			(Dollars in millions)			
December 31, 2005	$ 2.6	$ 1,497.5	$ (47.0)	$ 729.1	$ (3.9)	$ 2,178.3
Comprehensive income:						
Net income				600.7		600.7
Increase in fair value of cash flow hedges (net of $16.2 tax provision)			24.3			24.3
Minimum pension liability adjustment (net of $16.8 tax provision)			22.5			22.5
Comprehensive income						647.5
Postretirement plans and workers compensation obligations (net of $149.5 tax benefit):						
Accumulated actuarial loss, net of tax			(242.0)			
Prior service cost, net of tax			(7.0)			
			(249.0)			(249.0)
Dividends paid				(63.5)		(63.5)
Stock options exercised	0.1	15.5				15.6
Share-based compensation		21.9				21.9
Income tax benefits from stock options exercised		33.2				33.2
Employee stock purchases		4.5				4.5
Change in accounting for advanced stripping (net of $95.2 tax benefit)				(150.4)		(150.4)
Common stock repurchased					(99.8)	(99.8)
December 31, 2006	$ 2.7	$ 1,572.6	$ (249.2)	$ 1,115.9	$ (103.7)	$ 2,338.3
Comprehensive income:						
Net income				264.3		264.3
Increase in fair value of cash flow hedges			21.9			21.9
Postretirement plans and workers compensation obligations (net of $50.2 tax provision)			87.2			87.2
Comprehensive income						373.4

Dividends paid				(63.7)		(63.7)
Patriot Coal Corporation spin-off			73.0	(375.1)		(302.1)
Stock options exercised		26.2				26.2
Income tax benefits from stock options exercised		96.7				96.7
Employee stock purchases		6.4				6.4
Share-based compensation		48.8				48.8
Shares relinquished					(4.3)	(4.3)
December 31, 2007	$ 2.7	$ 1,750.7	$ (67.1)	$ 941.4	$ (108.0)	$ 2,519.7
Comprehensive income:						
Net income				953.5		953.5
Decrease in fair value of cash flow hedges (net of $178.2 tax benefit)			(217.9)			(217.9)
Postretirement plans and workers compensation obligations (net of $59.3 tax benefit)			(103.5)			(103.5)
Comprehensive income						632.1
Dividends paid				(64.9)		(64.9)
Patriot Coal Corporation spin-off adjustment				(26.5)		(26.5)
Stock options exercised	0.1	14.0				14.1
Employee stock purchases		5.2				5.2
Share-based compensation		34.9				34.9
Common stock repurchased					(199.8)	(199.8)
Shares relinquished					(11.0)	(11.0)
December 31, 2008	$ 2.8	$ 1,804.8	$ (388.5)	$ 1,803.5	$ (318.8)	$ 2,903.8

See accompanying notes to consolidated financial statements

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of Peabody Energy Corporation (the Company) and its affiliates. All intercompany transactions, profits and balances have been eliminated in consolidation.

Description of Business

The Company is engaged in the mining of steam coal for sale primarily to electric utilities and metallurgical coal for sale to industrial customers. The Company s mining operations are located in the United States (U.S.) and Australia, and include an equity interest in a mining operation in Venezuela. In addition to the Company s mining operations, the Company markets, brokers and trades coal. The Company s other energy related commercial activities include the development of mine-mouth coal-fueled generating plants, the management of its vast coal reserve and real estate holdings, and the evaluation of Btu Conversion technologies. The Company s Btu Conversion projects are designed to expand the uses of coal through various technologies such as coal-to-liquids and coal gasification.

Newly Adopted Accounting Pronouncements

In April 2007, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FASB Interpretation Number (FIN) 39-1, Amendment of FASB Interpretation No. 39 (FSP FIN 39-1). FSP FIN 39-1 amends certain provisions of FIN 39, Offsetting of Amounts Related to Certain Contracts, and permits companies to offset fair value amounts recognized for cash collateral receivables or payables against fair value amounts recognized for net derivative positions executed with the same counterparty under the same master netting arrangement. Prior to the implementation of FSP FIN 39-1, all positions executed with common counterparties were presented on a gross basis in the appropriate balance sheet line items. Effective January 1, 2008, in accordance with the provisions of FSP FIN 39-1, the Company offset its asset and liability coal trading derivative positions and other corporate hedging activities on a counterparty-by-counterparty basis if the contractual agreement provides for the net settlement of contracts with the counterparty in the event of default or termination of any one contract. The December 31, 2007 balances were reclassified to conform with the provisions of FSP FIN 39-1. See Note 5 for a presentation of the assets and liabilities from coal trading activities on a gross and net basis.

In February 2007, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 provides all entities with an option to report selected financial assets and liabilities at fair value. SFAS No. 159 was effective for the Company for the fiscal year beginning January 1, 2008. SFAS No. 159 did not have an impact on the accompanying consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. SFAS No. 157 applies under accounting pronouncements that require or permit fair value measurements, but the standard does not require any new fair value measurements. In February 2008, the FASB amended SFAS No. 157 to exclude leasing transactions and to delay the effective date by one year for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The Company adopted SFAS No. 157 on January 1, 2008. In October

2008, the FASB FSP No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active (FSP 157-3), which clarified the application of SFAS No. 157 in an inactive market and demonstrated how the fair value of a financial asset is determined when the market for that financial asset is inactive. FSP 157-3 was effective upon issuance,

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

including prior periods for which financial statements had not been issued. The adoption of FSP 157-3 did not have an impact on the Company s determination of fair value for financial assets. See Note 3 for additional details on fair value.

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN No. 48). This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company adopted the provisions of FIN No. 48 on January 1, 2007, and as a result, reported $135.0 million of net unrecognized tax benefits ($144.0 million gross) in its consolidated financial statements. Due to the valuation allowance recorded against the Company s deferred tax asset for net operating loss (NOL) carryforwards as of January 1, 2007, none of the $135.0 million required an adjustment to retained earnings upon adoption.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS No. 158). For fiscal years ending after December 15, 2006, SFAS No. 158 requires recognition of the funded status of pension and other postretirement benefit plans (an asset for overfunded status or a liability for underfunded status) in a company s balance sheet. In addition, the standard requires recognition of actuarial gains and losses, prior service cost, and any remaining transition amounts from the initial application of SFAS No. 87, Employers Accounting for Pensions (SFAS No. 87) and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions (SFAS No. 106) when determining a plan s funded status, with a corresponding charge to accumulated other comprehensive income (loss). The Company adopted SFAS No. 158 on December 31, 2006, and as a result, recorded a noncurrent liability of $376.1 million, which reflected the net underfunded status of the pension, retiree healthcare and workers compensation plans. The funded status of each plan was measured as the difference between the fair value of the assets and the projected benefit obligation (the funded status). SFAS No. 158 did not impact net income.

In March 2005, the Emerging Issues Task Force (EITF) issued EITF Issue No. 04-6, Accounting for Stripping Costs in the Mining Industry (EITF Issue No. 04-6). EITF Issue No. 04-6 and its interpretations require stripping costs incurred during a period to be attributed only to the inventory costs of the coal that is extracted during that same period. The Company adopted EITF Issue No. 04-6 on January 1, 2006 and utilized the cumulative effect adjustment approach whereby the cumulative effect adjustment reduced retained earnings by $150.4 million, net of tax. This non-cash item is excluded from the consolidated statements of cash flows. Advance stripping costs are primarily expensed as incurred.

Accounting Pronouncements not Yet Implemented

In June 2008, the FASB issued FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 addresses whether instruments granted in share-based payment awards that entitle their holders to receive nonforfeitable dividends or dividend equivalents before vesting should be considered participating securities and need to be included in the earnings allocation in computing EPS under the two-class method. The two-class method of computing EPS is an earnings allocation formula that determines EPS for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008 (January 1, 2009 for the Company) with all prior period EPS data being adjusted retrospectively. The adoption of FSP EITF 03-6-1 will not have a material effect on the Company s results of operations, EPS or financial condition.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 expands the

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

disclosure requirements for derivative instruments and hedging activities. This statement specifically requires entities to provide enhanced disclosures addressing the following: (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133) and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008 (January 1, 2009 for the Company). While SFAS No. 161 will have an impact on the Company s disclosures, it will not affect the Company s results of operations or financial condition.

In May 2008, the FASB issued FSP No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement) (FSP APB 14-1). FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not considered debt instruments within the scope of APB Opinion No. 14, Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants . FSP APB 14-1 also specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the issuer s nonconvertible debt borrowing rate when recognizing interest cost in subsequent periods. FSP APB 14-1 is effective for fiscal years and interim periods beginning after December 15, 2008 (January 1, 2009 for the Company) and will require retrospective application for all periods presented. If FSP APB 14-1 had been applied, the estimated impact on net income for the year ended December 31, 2008 would have been $0.6 million of expense, net of tax. The Company s current estimate of the impact on its consolidated balance sheet as of the date of adoption is noted in the table below.

	Increase (decrease) due to application of FSP APB 14-1 (Dollars in Millions)	
Investments and other assets	$	(8.4)
Deferred income taxes (long-term asset)		(139.9)
Total assets	$	(148.3)
Long-term debt, less current maturities	$	(362.6)
Total liabilities		(362.6)
Additional paid-in capital		215.4
Retained earnings		(1.1)
Total stockholders equity		214.3
Total liabilities and stockholders equity	$	(148.3)

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for noncontrolling interests in partially-owned consolidated subsidiaries and the loss of control of subsidiaries. SFAS No. 160 requires noncontrolling interests (minority interests) to be reported as a separate component of equity. In addition, this statement requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for the Company). Early adoption is not allowed. The adoption of SFAS No. 160 will not have a material effect on the Company s results of operations or financial condition.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations (SFAS No. 141(R)), which replaces SFAS No. 141. SFAS No. 141(R) changes the principles and requirements for the recognition

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and measurement of identifiable assets acquired, liabilities assumed, and any noncontrolling interest of an acquiree in the financial statements of an acquirer. This statement also provides guidance for the recognition and measurement of goodwill acquired in a business combination and related disclosure. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for the Company).

Sales

The Company s revenue from coal sales is realized and earned when risk of loss passes to the customer. Under the typical terms of the Company s coal supply agreements, title and risk of loss transfer to the customer at the mine or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that serves each of the Company s mines. The Company incurs certain add-on taxes and fees on coal sales. Coal sales are reported including taxes and fees charged by various federal and state governmental bodies. Coal sales includes the freight charges on destination customer contracts.

Other Revenues

Other revenues include royalties related to coal lease agreements, sales agency commissions, farm income, property and facility rentals, generation development activities, net revenues from coal trading activities accounted for under SFAS No. 133, as amended, and contract termination or restructuring payments. Royalty income generally results from the lease or sublease of mineral rights to third parties, with payments based upon a percentage of the selling price or an amount per ton of coal produced.

Discontinued Operations and Assets Held for Sale

The Company classifies items within discontinued operations in the consolidated statements of operations when the operations and cash flows of a particular component (defined as operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the entity) of the Company have been (or will be) eliminated from the ongoing operations of the Company as a result of a disposal transaction, and the Company will no longer have any significant continuing involvement in the operations of that component. See Note 2 for additional details related to discontinued operations and assets held for sale.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Inventories

Materials and supplies and coal inventory are valued at the lower of average cost or market. Raw coal represents coal stockpiles that may be sold in current condition or may be further processed prior to shipment to a customer. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs.

Assets and Liabilities from Coal Trading Activities

The Company s coal trading activities are evaluated under SFAS No. 133, as amended. Trading contracts that meet the SFAS No. 133 definition of a derivative are accounted for at fair value, while contracts that do not qualify as derivatives are accounted for under the accrual method.

The Company s asset and liability coal trading derivative positions and other corporate hedging activities are offset on a counterparty-by-counterparty basis if the contractual agreement provides for the net settlement

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of contracts with the counterparty in the event of default or termination of any one contract in accordance with FSP FIN 39-1.

The Company s trading contracts are reflected at fair value and are included in Assets and liabilities from coal trading activities in the consolidated balance sheets as of December 31, 2008 and 2007. Under EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, all mark-to-market gains and losses on energy trading contracts (including derivatives and hedged contracts) are presented on a net basis in the consolidated statement of operations in Other revenues, even if settled physically.

Property, Plant, Equipment and Mine Development

Property, plant, equipment and mine development are recorded at cost. Interest costs applicable to major asset additions are capitalized during the construction period, including $1.5 million for the year ended December 31, 2007, and $3.0 million for the year ended December 31, 2006. There was no capitalized interest for the year ended December 31, 2008.

Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Maintenance and repairs are charged to operating costs as incurred. Costs incurred to develop coal mines or to expand the capacity of operating mines are capitalized. Costs incurred to maintain current production capacity at a mine and exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Costs to acquire computer hardware and the development and/or purchase of software for internal use are capitalized and depreciated over the estimated useful lives.

Coal reserves are recorded at cost, or at fair value in the case of acquired businesses. The net book value of coal reserves totaled $5.4 billion as of December 31, 2008 and $5.6 billion as of December 31, 2007. These coal reserves include mineral rights for leased coal interests and advance royalties that had a net book value of $4.1 billion as of December 31, 2008 and $3.9 billion as of December 31, 2007. The remaining net book value of coal reserves of $1.3 billion at December 31, 2008 and $1.7 billion at December 31, 2007 relates to coal reserves held by fee ownership. Amounts attributable to properties where the Company was not currently engaged in mining operations or leasing to third parties and, therefore, the coal reserves were not currently being depleted was $1.9 billion as of December 31, 2008 and $2.1 billion as of December 31, 2007.

Depletion of coal reserves and amortization of advance royalties is computed using the units-of-production method utilizing only proven and probable reserves (as adjusted for recoverability factors) in the depletion base. Mine development costs are principally amortized over the estimated lives of the mines using the straight-line method. Depreciation of plant and equipment (excluding life of mine assets) is computed using the straight-line method over the estimated useful lives as follows:

	Years
Building and improvements	10 to 20
Machinery and equipment	3 to 39

Leasehold improvements	Life of Lease

In addition, certain plant and equipment assets associated with mining are depreciated using the straight-line method over the estimated life of the mine, which varies from one to 39 years.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments in Joint Ventures

The Company accounts for its investments in less than majority owned corporate joint ventures under either the equity or cost method. The Company applies the equity method to investments in joint ventures when it has the ability to exercise significant influence over the operating and financial policies of the joint venture. Investments accounted for under the equity method are initially recorded at cost, and any difference between the cost of the Company s investment and the underlying equity in the net assets of the joint venture at the investment date is amortized over the lives of the related assets that gave rise to the difference. The Company s pro rata share of earnings from joint ventures and basis difference amortization is reported in the consolidated statements of operations in Income from equity affiliates. Included in the Company s equity method investments is its 25.5% interest in Carbones del Guasare, which owns and operates the Paso Diablo Mine in Venezuela. The table below summarizes the book value of the Company s equity method investments, which is reported in Investments and other assets in the consolidated balance sheets, the income from its equity affiliates and dividends received from its equity:

	Book Value at December 31,		Income From Equity Affiliates for the Year Ended December 31,			Dividends Received from Equity Affiliates for the Year Ended December 31,		
	2008	2007	2008	2007	2006	2008	2007	2006
	(Dollars in millions)							
Interest in Carbones del Guasare	$ 54.2	$ 68.4	$ 5.7	$ 21.2	$ 28.0	$ 19.9	$ 12.9	$ 18.1
Other equity method investments	7.0	8.3	(5.7)	(6.7)	(5.2)			
Total equity method investments	$ 61.2	$ 76.7	$	$ 14.5	$ 22.8	$ 19.9	$ 12.9	$ 18.1

Generation Development Costs

The Company owns a 5.06% interest in the Prairie State Energy Campus (Prairie State), which is currently under construction. The Company has capitalized development costs of $69.7 million and $28.8 million that were recorded as part of Investments and other assets in the consolidated balance sheets as of December 31, 2008 and 2007, respectively.

Asset Retirement Obligations

SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The Company s asset retirement obligation (ARO) liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with applicable reclamation laws as defined by each mining permit.

The Company estimates its ARO liabilities for final reclamation and mine closure based upon detailed engineering calculations of the amount and timing of the future cash spending for a third-party to perform the required work. Spending estimates are escalated for inflation and then discounted at the credit-adjusted, risk-free rate. The Company records an ARO asset associated with the discounted liability for final reclamation and mine closure. The obligation and corresponding asset are recognized in the period in which the liability is incurred. The ARO asset is amortized on the units-of-production method over its expected life and the ARO liability is accreted to the projected spending date. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free rate. The Company also recognizes an obligation for contemporaneous reclamation liabilities incurred as a result of surface mining. Contemporaneous reclamation consists primarily of grading, topsoil replacement and re-vegetation of backfilled pit areas.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Environmental Liabilities

Included in Other noncurrent liabilities are accruals for other environmental matters that are recorded in operating expenses when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Accrued liabilities are exclusive of claims against third parties and are not discounted. In general, costs related to environmental remediation are charged to expense.

Income Taxes

Income taxes are accounted for using a balance sheet approach in accordance with SFAS No. 109, Accounting for Income Taxes. The Company accounts for deferred income taxes by applying statutory tax rates in effect at the date of the balance sheet to differences between the book and tax basis of assets and liabilities. A valuation allowance is established if it is more likely than not that the related tax benefits will not be realized. In determining the appropriate valuation allowance, the Company considers projected realization of tax benefits based on expected levels of future taxable income, available tax planning strategies, and the overall deferred tax position.

FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company adopted this interpretation effective January 1, 2007.

Postretirement Health Care and Life Insurance Benefits

The Company accounts for postretirement benefits other than pensions in accordance with SFAS No. 106, which requires the costs of benefits to be provided to be accrued over the employees period of active service. These costs are determined on an actuarial basis. As a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of postretirement benefits.

Pension Plans

The Company sponsors non-contributory defined benefit pension plans accounted for in accordance with SFAS No. 87, which requires that the cost to provide the benefits be accrued over the employees period of active service. These costs are determined on an actuarial basis. SFAS No. 158 amended SFAS No. 87 and as a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of the defined benefit pension plans.

Postemployment Benefits

The Company provides postemployment benefits to qualifying employees, former employees and dependents and accounts for these benefits on the accrual basis in accordance with SFAS No. 112 Employers Accounting for Postemployment Benefits. Postemployment benefits include workers compensation occupational disease, which is accounted for on the actuarial basis over the employees period of active service; workers compensation traumatic injury claims, which are accounted for based on estimated loss rates applied to payroll and claim reserves determined by independent actuaries and claims administrators; disability income benefits, which are accrued when a claim occurs; and continuation of medical benefits, which are recognized when the obligation occurs. As a result of the adoption of SFAS No. 158 on December 31, 2006, the Company s consolidated balance sheet reflects the funded status of postemployment benefits.

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivatives

SFAS No. 133, as amended, requires the recognition at fair value of all derivatives as assets or liabilities on the consolidated balance sheets. Gains or losses from derivative financial instruments designated as fair value hedges are recognized immediately in the consolidated statements of operations, along with the offsetting gain or loss related to the underlying hedged item.

Gains or losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders equity until settlement (or until hedge ineffectiveness is determined), whereby gains or losses are reclassified to the consolidated statements of operations in conjunction with the recognition of the underlying hedged item. To the extent that the periodic changes in the fair value of the derivatives are not effective, or if the hedge ceases to qualify for hedge accounting, the ineffective portion of the periodic non-cash changes are recorded in the consolidated statement of operations in the period of the change. The potential for hedge ineffectiveness is present in the design of the Company s cash flow hedge relationships (see Note 3 for additional details).

Use of Estimates in the Preparation of the Consolidated Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Impairment of Long-Lived Assets

The Company records impairment losses on long-lived assets used in operations when events and circumstances indicate that assets might be impaired and the undiscounted cash flows estimated to be generated by those assets under various assumptions are less than the carrying amounts of the assets. Impairment losses are measured by comparing the estimated fair value of the impaired asset to its carrying amount. There were no impairment losses recorded during the years ended December 31, 2008, 2007 and 2006.

Fair Value

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company adopted SFAS No. 157 effective January 1, 2008. Although the adoption of SFAS No. 157 did not materially impact the Company s financial condition, results of operations or cash flows, additional disclosures related to fair value measurements are now required. See Note 3 for additional information.

Foreign Currency

The Company s foreign subsidiaries utilize the U.S. dollar as their functional currency. As such, monetary assets and liabilities are remeasured at year-end exchange rates while non-monetary items are remeasured at historical rates. Income and expense accounts are remeasured at the average rates in effect during the year, except for those expenses related to balance sheet amounts that are remeasured at historical exchange rates. Gains and losses from foreign currency remeasurement related to tax balances are included as a component of income tax expense while all other remeasurement gains and losses are included in operating costs and expenses. The foreign currency remeasurement gain for the year ended December 31, 2008, was $69.9 million. The foreign currency remeasurement loss for the year end December 31, 2007 was $60.4 million and for December 31, 2006 was $12.8 million.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Share-Based Compensation

The Company accounts for share-based compensation in accordance with the fair value recognition provisions of SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123(R)), which the Company adopted using the modified prospective option on January 1, 2006. Under SFAS No. 123(R), share-based compensation expense is generally measured at the grant date and recognized as expense over the vesting period of the award.

Exploration and Drilling Costs

Exploration expenditures are charged to operating costs as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves.

Advance Stripping Costs

Pre-production: At existing surface operations, additional pits may be added to increase production capacity in order to meet customer requirements. These expansions may require significant capital to purchase additional equipment, expand the workforce, build or improve existing haul roads and create the initial pre-production box cut to remove overburden (i.e., advance stripping costs) for new pits at existing operations. If these pits operate in a separate and distinct area of the mine, the costs associated with initially uncovering coal (i.e., advance stripping costs incurred for the initial box cuts) for production are capitalized and amortized over the life of the developed pit consistent with coal industry practices.

Post-production: Advance stripping costs related to post-production are expensed as incurred. Where new pits are routinely developed as part of a contiguous mining sequence, the Company expenses such costs as incurred. The development of a contiguous pit typically reflects the planned progression of an existing pit, thus maintaining production levels from the same mining area utilizing the same employee group and equipment.

Reclassifications

Certain amounts in prior periods have been reclassified to conform with the presentation of 2008, with no effect on previously reported net income or stockholders equity.

(2) Discontinued Operations

Patriot Coal Corporation

On October 31, 2007, the Company spun off portions of its formerly Eastern U.S. Mining segment through a dividend of all outstanding shares of Patriot Coal Corporation (Patriot), which is now an independent public company traded on the New York Stock Exchange (symbol PCX). The spin-off included eight company-operated mines, two joint venture mines and numerous contractor operated mines serviced by eight coal preparation facilities along with 1.2 billion tons of proven and probable coal reserves. Revenues, pretax income (loss) and the income tax provision (benefit) related to the spun off operations were as follows:

	Year Ended December 31, 2008	2007	2006
	(Dollars in millions)		
Revenues	$ 431.2	$ 1,024.5	$ 1,147.9
Income (loss) before income taxes and minority interests	(23.0)	(235.2)	67.9
Income tax provision (benefit)	(8.9)	(81.5)	8.6

Revenues from the spun-off operations are the result of supply agreements the Company entered into with Patriot to meet commitments under non-assignable, pre-existing customer agreements sourced from Patriot

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

mining operations. The Company makes no profit as part of these arrangements and only sources coal from Patriot to meet customer obligations. Included in the loss from discontinued operations for the year ended December 31, 2008 was the first quarter write-off of a $19.4 million receivable related to coal excise taxes previously paid on export shipments produced from discontinued operations. As part of the Patriot spin-off, the Company retained a receivable for coal excise tax refunds on export shipments that had previously been ruled unconstitutional by the appellate court. The U.S. Supreme Court reversed the appellate court s ruling on April 15, 2008, and the Company recorded a charge to discontinued operations.

In October 2008, the Energy Improvement and Extension Act of 2008 was enacted, which contained provisions that allow for the refund of coal excise tax collected on coal exported from the U.S. between January 1, 1990 and the date of the legislation. The Company has resubmitted a claim for refund, and that claim is subject to approval of the Internal Revenue Service (IRS). By statute, the IRS has 180 days to approve the refund claims and another 180 days to pay the refund with interest. Once the Company is notified of an approved amount, the final refund will be recorded to discontinued operations.

The Company had also entered into a transition services agreement, which expired in 2008, to provide certain administrative and other services to Patriot. Under this agreement, the Company billed $1.4 million for services during 2008 and $0.9 million for services during 2007.

The assets, liabilities and minority interests of the Patriot related discontinued operations as of December 31, 2008 and 2007 are shown below.

	December 31, 2008		December 31, 2007	
	(Dollars in millions)			
Assets				
Current assets				
Other current assets	$	51.0	$	113.9
Total current assets		51.0		113.9
Noncurrent assets				
Investments and other assets		4.9		39.6
Total assets	$	55.9	$	153.5
Liabilities				
Current liabilities				
Accounts payable and accrued expenses	$	69.1	$	180.4
Total current liabilities		69.1		180.4
Noncurrent liabilities				

Other noncurrent liabilities		12.8		33.2
Total liabilities	$	81.9	$	213.6

Other current assets included receivables from customers in relation to the supply agreements with Patriot, and accounts payable and accrued expenses included the amounts due to Patriot on these pass-through transactions. Also included in other current assets is the current portion of deferred taxes related to these operations. Accounts payable and accrued expenses include an accrual for charges related to losses on firm purchase commitments that extend through 2010.

During 2008, the Company recognized an additional dividend to Patriot of $26.5 million related to the true-up of deferred tax assets associated with Patriot.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other

In December 2008, the Company sold its Baralaba Mine, a non-strategic Australian mine, for $25.8 million of cash proceeds and an Australian dollar note receivable valued at approximately $8.7 million on December 31, 2008, resulting in a gain of $26.2 million. The non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows. Revenues related to these operations for the years ended December 31, 2008, 2007 and 2006 were $18.8 million, $22.1 million and $10.2 million, respectively. Loss before income taxes and minority interests related to these operations was $15.7 million, $10.6 million and $10.6 million for the years ended December 31, 2008, 2007 and 2006, respectively. Income tax benefits for all periods presented were completely offset by valuation allowances recorded against the deferred tax assets created by the operating losses.

In December 2008, the Company committed to the divestiture of certain non-strategic Midwestern U.S. mining assets. At December 31, 2008, the carrying amount of assets held for sale totaled $12.6 million, which was included in Investments and other assets. The carrying amount of liabilities associated with assets held for sale totaled $9.4 million, which was included in Other noncurrent liabilities. Revenues related to these operations for the years ended December 31, 2008, 2007 and 2006 were $30.6 million, $39.5 million and $47.3 million, respectively. Loss, net of tax, related to these operations was $27.7 million, $8.2 million and $6.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(3) Risk Management and Fair Value Measurements

Employees

As of December 31, 2008, the Company had approximately 7,200 employees. As of December 31, 2008, approximately 28% of the Company s hourly employees were represented by organized labor unions and generated 10% of the 2008 coal production. Relations with its employees and, where applicable, organized labor are important to the Company s success.

United States Labor Relations

Hourly workers at the Company s Kayenta Mine in Arizona are represented by the United Mine Workers of America (UMWA) under the Western Surface Agreement, which is effective through September 2, 2013. This agreement covers approximately 7% of the Company s U.S. subsidiaries hourly employees, who generated 4% of the Company s U.S. production during the year ended December 31, 2008.

Hourly workers at the Company s Willow Lake Mine in Illinois are represented by the International Brotherhood of Boilermakers under a labor agreement that expires April 15, 2011. This agreement covers approximately 8% of the Company s U.S. subsidiaries hourly employees, who generated approximately 2% of the Company s U.S. production during the year ended December 31, 2008.

Australia Labor Relations

The Australian coal mining industry is unionized and the majority of workers employed at the Company s Australian Mining operations are members of trade unions. The Construction Forestry Mining and Energy Union represents the

Company s Australian subsidiary s hourly production employees, including those employed through contract mining relationships. The labor agreements at the Company s Australian subsidiary s Millennium Mine were renewed in 2007 and expire in 2010. The labor agreements at the Company s Australian subsidiary s Chain Valley Mine and Wambo Mine coal handling plant were renewed in 2008 and expire in 2011. The labor agreements for the Company s Australian subsidiary s Wambo Underground Mine and North Goonyella Mine are under negotiation. The Wambo Underground Mine agreement expired in November 2008 while the North Goonyella Mine s existing agreement expires in May 2009.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Risk Management

The Company is exposed to various types of risk in the normal course of business, including fluctuations in commodity prices, interest rates and foreign currency exchange rates. These risks are actively monitored in an effort to ensure compliance with the risk management policies of the Company. In most cases, commodity price risk (excluding coal trading activities) related to the sale of coal is mitigated through the use of long-term, fixed-price contracts rather than financial instruments, while commodity price risk related to materials used in production is managed through the use of fixed price and cost plus contracts and derivatives. Interest rate and foreign currency exchange risk are managed through the use of forward contracts, swaps and options. The following summarizes the Company s interest rate, currency and commodity positions at December 31, 2008:

	Notional Amount by Term to Maturity							Account Classification by		
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**2014 and Thereafter**	**Cash Flow Hedge**	**Fair Value Hedge**	**Fair Value Asset (Liability)**
Interest Rate Swaps										
Fixed-to-floating (dollars in millions)	$ 320.0	$	$	$	$	$ 220.0	$ 100.0	$	$ 320.0	$ 12.5
Floating-to-fixed (dollars in millions)	$ 186.0	$	$	$ 120.0	$	$	$ 66.0	$ 186.0	$	$ (21.8)
Foreign Currency										
A$:US$ forwards and options (A$ millions)	2,408.0	1,161.7	826.3	420.0				2,408.0		(283.8)
Commodity Contracts										
Diesel fuel hedge contracts (million gallons)	189.4	98.4	64.4	26.6				189.4		(176.5)
U.S. explosives hedge contracts (million MMbtu)	6.5	3.6	2.9					6.5		(18.2)

Interest Rate Swaps

The Company s usage of interest rate swaps is discussed in Note 12.

Foreign Currency Risk

The Company utilizes currency forwards and options to hedge currency risk associated with anticipated Australian dollar expenditures.

Diesel Fuel and Explosives Hedges

The Company uses a combination of forward contracts with its suppliers and financial derivative contracts, which are primarily swap contracts with financial institutions, to manage commodity risk associated with diesel fuel in the U.S. and Australia (non-contractor mines) and explosives in the U.S. Explosives costs in Australia are generally included in the fees paid to the Company s contract miners.

Hedge Ineffectiveness

The Company assesses both at inception and at least quarterly thereafter, whether the derivatives used in hedging activities are highly effective at offsetting the changes in the anticipated cash flows of the hedged item. The effective portion of the change in the fair value is recorded as a separate component of stockholders equity until the hedged transaction occurs, whereby gains and losses are reclassified to the consolidated statement of operations in conjunction with the recognition of the underlying hedged item. The ineffective portion of the derivative s change in fair value is recorded in the consolidated statement of operations. In addition, if the hedging relationship ceases to be highly effective, or it becomes probable that a forecasted

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

transaction is no longer expected to occur, gains and losses on the derivative are recorded to the consolidated statements of operations.

A measure of ineffectiveness is inherent in hedging future diesel fuel purchases with derivative positions based on crude oil or other mid-distillate commodities, especially given the recent volatility in the prices of refined products.

The Company s hedging of future explosives purchases is primarily through the use of derivative positions based on natural gas, which closely matches the contractual purchase price of explosives since price changes occur in a constant ratio of MMBtu per ton in the manufacture of explosives and generally carry a fixed surcharge.

In some instances, the Company has designated an existing derivative as a hedge and, thus, the derivative has a non-zero fair value at hedge inception. The off-market nature of these derivatives, which is best described as an embedded financing element within the derivative, is a source of ineffectiveness. In other instances, the Company uses a derivative that settles at a time later than the occurrence of the cash flow being hedged. The hedge yields ineffectiveness to the extent the fair value of the hedged item and the derivative hedge contract do not move by identical amounts.

For the year ended December 31, 2008, the Company recognized $5.0 million of higher operating costs related to hedge ineffectiveness. During 2007 and 2006, the Company did not recognize any hedge ineffectiveness.

Performance and Credit Risk

The Company s concentration of performance and credit risk is substantially with electric utilities, energy producers and energy marketers. The Company s policy is to independently evaluate each customer s creditworthiness prior to entering into transactions and to regularly monitor the credit extended. If the Company engages in a transaction with a counterparty that does not meet its credit standards, the Company seeks to protect its position by requiring the counterparty to provide an appropriate credit enhancement. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for the Company s benefit to serve as collateral in the event of a failure to pay. In general, increases in coal price volatility and the Company s trading activity resulted in greater exposure to its coal-trading counterparties during 2008.

In addition to credit risk, performance risk includes the possibility that a counterparty fails to deliver agreed production or trading volumes. When appropriate (as determined by its credit management function), the Company has taken steps to reduce its exposure to customers or counterparties whose credit has deteriorated and who may pose a higher risk of failure to perform under their contractual obligations. These steps include obtaining letters of credit or cash collateral, requiring prepayments for shipments or the creation of customer trust accounts held for the Company s benefit to serve as collateral in the event of a failure to pay. To reduce its credit exposure related to trading and brokerage activities, the Company seeks to enter into netting agreements with counterparties that permit the Company to offset receivables and payables with such counterparties.

The Company conducts its various hedging activities related to foreign currency, interest rate management, and fuel and explosives exposures with a variety of highly-rated commercial banks. In light of the recent turmoil in the financial markets the Company continues to closely monitor counterparty creditworthiness.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value Measurements Risk Management and Coal Trading

The following table summarizes the income statement classification for the Company s financial instruments for which fair value is measured on a recurring basis:

	Income Statement Classification	
Financial Instrument	**Gains/Losses - Realized**	**Gains/Losses - Unrealized[1]**
Commodity swaps and options coal trading activities	Other revenues	Other revenues
Commodity swaps and options other than coal	Operating costs and expenses	
Physical commodity purchase/sale contracts coal trading activities	Other revenues	Other revenues
Interest rate swaps	Interest expense	
Foreign currency forwards and options	Operating costs and expenses	

(1) Gains and losses on derivative financial instruments designated as cash flow hedges are recorded as a separate component of stockholders equity until settlement of underlying transaction (or until the hedge ineffectiveness is determined).

As discussed in Note 1, the Company adopted SFAS No. 157 effective January 1, 2008. Although the adoption of SFAS No. 157 did not materially impact the Company s financial condition, results of operations or cash flows, additional disclosures related to fair value measurements are now required. SFAS No. 157 establishes a three-level fair value hierarchy that categorizes assets and liabilities measured at fair value based on the observability of the inputs utilized in the valuation. These levels include: Level 1, inputs are quoted prices in active markets for the identical assets or liabilities; Level 2, inputs other than quoted prices included in Level 1 that are directly or indirectly observable through market-corroborated inputs; and Level 3, inputs are unobservable, or observable but cannot be market-corroborated, requiring the Company to make assumptions about pricing by market participants.

The following table sets forth as of December 31, 2008 the hierarchy of the Company s net financial asset (liability) positions for which fair value is measured on a recurring basis:

	Level 1	**Level 2**	**Level 3**	**Total**
		(Dollars in millions)		
Commodity swaps and options coal trading activities	$ (17.0)	$ 233.7	$ (1.1)	$ 215.6
Commodity swaps and options other than coal		(194.7)		(194.7)
Physical commodity purchase/sale contracts coal trading activities		104.1	38.9	143.0
Interest rate swaps		(9.3)		(9.3)
Foreign currency forwards and options		(283.8)		(283.8)

Total net financial assets (liabilities)	$ (17.0)	$ (150.0)	$ 37.8	$ (129.2)

For Level 1 and 2 financial assets and liabilities, the Company utilizes both direct and indirect observable price quotes, including LIBOR yield curves, New York Mercantile Exchange indices and other market quotes. Below is a summary of the Company s valuation techniques for Level 1 and 2 financial assets and liabilities:

Commodity swaps and options coal trading activities: generally valued based on unadjusted quoted prices in active markets (Level 1) or a valuation that is corroborated by the use of market-based pricing (Level 2).

Commodity swaps and options other than coal: generally valued based on a valuation that is corroborated by the use of market-based pricing (Level 2).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Physical commodity purchase/sale contracts coal trading activities: purchases and sales at locations with significant market activity corroborated by market-based information (Level 2).

Interest rate swaps: valued based on quoted inputs from counterparties corroborated with observable market data (Level 2).

Foreign currency forwards and options: valued utilizing inputs obtained in quoted public markets (Level 2).

Commodity swaps and options and physical commodity purchase/sale contracts transacted in less liquid markets or contracts, such as long-term arrangements with limited price availability were classified in Level 3. These instruments or contracts are valued based on quoted inputs from brokers or counterparties, or reflect methodologies that consider historical relationships among similar commodities to derive the Company s best estimate of fair value. The Company has consistently applied these valuation techniques in all periods presented, and believes it has obtained the most accurate information available for the types of derivative contracts held.

The following table summarizes the changes in the Company s recurring Level 3 net financial assets:

	Year Ended December 31, 2008 (Dollars in millions)	
Beginning of period	$	128.7
Total gains or losses (realized/unrealized):		
Included in earnings		(9.8)
Included in other comprehensive income		3.4
Purchases, issuances and settlements		(58.8)
Transfers in and/or out		(25.7)
December 31, 2008	$	37.8

The following table summarizes the changes in unrealized losses relating to Level 3 net financial assets held both as of January 1 and December 31, 2008:

	Year Ended December 31, 2008 (Dollars in millions)	
Changes in unrealized losses[1]	$	(34.8)

(1) For the periods presented, unrealized gains and losses from Level 3 items are offset by unrealized gains and losses on positions classified in Level 1 or 2, as well as other positions that have been realized during the applicable periods.

Fair Value — Other Financial Instruments

The following methods and assumptions were used by the Company in estimating its fair value disclosures for other financial instruments as of December 31, 2008 and 2007:

Cash and cash equivalents, accounts receivable and accounts payable and accrued expenses have carrying values which approximate fair value due to the short maturity or the financial nature of these instruments.

Long-term debt fair value estimates are based on observed prices for securities with an active trading market when available, and otherwise on estimated borrowing rates to discount the cash flows to their present value. The 7.875% Senior Notes due 2026 are net of unamortized note discount.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest rate swaps are valued based on quoted inputs from counterparties corroborated with observable market data (Level 2).

The carrying amounts and estimated fair values of the Company s debt are summarized as follows:

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(Dollars in millions)			
Long-term debt	$ 3,156.2	$ 2,734.8	$ 3,273.1	$ 3,471.6

(4) Resource Management and Other Commercial Events

In 2008, the Company sold approximately 58 million tons of non-strategic coal reserves and surface lands located in Kentucky for $21.5 million cash proceeds and a note receivable of $54.9 million and recognized a gain of $54.0 million. The note receivable is being paid in two installments, $30.0 million of which was received in December 2008. The balance is to be paid in June 2009. The non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows.

In 2007, the Company sold approximately 172 million tons of coal reserves and surface lands to the Prairie State equity partners. The Company recognized a gain totaling $26.4 million and received $114.3 million in cash proceeds associated with this transaction. See Note 19 for additional information regarding Prairie State.

In 2007, the Company exchanged oil and gas rights and assets in more than 860,000 acres in the Illinois Basin, West Virginia, New Mexico and the Powder River Basin for coal reserves in West Virginia and Kentucky and $15.0 million in cash proceeds. The Company s subsidiaries, including one subsidiary now owned by Patriot, received approximately 40 million tons of coal reserves. Based on the fair value of the coal reserves received, the Company recognized a $50.5 million gain on the exchange. The non-cash portion of this transaction was excluded from the investing section of the consolidated statement of cash flows.

In 2006, the Company exchanged approximately 63 million tons of coal reserves at its Caballo mining operation for approximately 46 million tons of coal reserves contiguous with the Company s North Antelope Rochelle mining operation. Based on the fair value of the coal reserves exchanged, the Company recognized a gain totaling $39.2 million. This non-cash transaction was excluded from the investing section of the consolidated statement of cash flows.

In 2006, the Company recognized $35.8 million in gains related to the settlement of commitments by a third-party coal producer following a brokerage contract restructuring. The gains are included in Other revenues in the consolidated statements of operations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Assets and Liabilities from Coal Trading Activities

The fair value of assets and liabilities from coal trading activities is set forth below:

	December 31,			
	2008		2007	
	Gross Basis	Net Basis	Gross Basis	Net Basis
	(Dollars in millions)			
Assets from coal trading activities	$ 1,969.7	$ 662.8	$ 967.1	$ 349.8
Liabilities from coal trading activities	(1,548.5)	(304.2)	(918.6)	(301.8)
Subtotal	421.2	358.6	48.5	48.0
Margin held[1]	(62.6)		(0.5)	
Net assets from coal trading activities	$ 358.6	$ 358.6	$ 48.0	$ 48.0

[1] Represents margin held from counterparties that was netted in accordance with FSP FIN 39-1 and does not represent the Company s total margin held or posted.

The increase in pricing since December 31, 2007 and higher trading volumes have significantly increased the value of the Company s trading portfolio in 2008. As of December 31, 2008, forward contracts made up 50% and 77% of the Company s trading assets and liabilities, respectively; financial swaps represent most of the remaining balances. The fair value of coal trading positions designated as cash flow hedges of anticipated future sales was an asset of $220.4 million as of December 31, 2008 and a liability of $44.1 million as of December 31, 2007. The net value of trading positions, including those designated as hedges of future cash flows, represents the fair value of the trading portfolio.

Of the coal trading derivatives and related hedge contracts in the Company s trading portfolio as of December 31, 2008, 94% were valued utilizing prices from over-the-counter market sources, adjusted for coal quality and traded transportation differentials and 6% of the Company s contracts were valued based on similar market transactions.

As of December 31, 2008, the estimated future realization of the value of the Company s trading portfolio was as follows:

Year of Expiration	Percentage of Portfolio
2009	75%
2010	13%

2011	11%
2012	1%
	100%

At December 31, 2008, 66% of the Company s credit exposure related to coal trading activities with investment grade counterparties and 34% with non-investment grade counterparties. The Company s coal trading operations traded 192.9 million tons, 166.5 million tons and 79.1 million tons for the years ended December 31, 2008, 2007 and 2006, respectively.

(6) Accounts Receivable Securitization

The Company has an accounts receivable securitization program through its wholly-owned, bankruptcy-remote subsidiary (Seller). Under the program, the Company contributes undivided interests in a pool of eligible trade receivables to the Seller, which then sells, without recourse, to a multi-seller, asset-backed commercial paper conduit (Conduit). Purchases by the Conduit are financed with the sale of highly rated

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

commercial paper. The Company utilizes proceeds from the sale of its accounts receivable as an alternative to other forms of debt, effectively reducing its overall borrowing costs. The funding cost of the securitization program was $10.8 million, $11.2 million and $1.9 million for the years ended December 31, 2008, 2007 and 2006, respectively. The securitization program and the underlying facilities will effectively expire in May 2009.

The securitization transactions have been recorded as sales, with those accounts receivable sold to the Conduit removed from the consolidated balance sheets. The amount of undivided interests in accounts receivable sold to the Conduit was $275.0 million as of December 31, 2008 and 2007 and $219.2 million as of December 31, 2006.

The Seller is a separate legal entity whose assets are available first and foremost to satisfy the claims of its creditors. Eligible receivables, as defined in the securitization agreement, consist of trade receivables from most of the Company s U.S. subsidiaries, and are reduced for certain items such as past due balances and concentration limits. Of the eligible pool of receivables contributed to the Seller, undivided interests in only a portion of the pool are sold to the Conduit. The Company (the Seller) continues to own $75.6 million of receivables as of December 31, 2008, which represents collateral supporting the securitization program. The Seller s interest in these receivables is subordinate to the Conduit s interest in the event of default under the securitization agreement. If the Company defaulted under the securitization agreement or if its pool of eligible trade receivables decreased significantly, the Company could be prohibited from selling any additional receivables in the future under the agreement.

(7) Earnings per Share

A reconciliation of weighted-average shares outstanding follows:

	Year Ended December 31,		
	2008	2007	2006
Weighted-average shares outstanding basic	268,860,528	264,068,180	263,419,344
Dilutive impact of stock options, restricted stock units, employee stock purchase plan, and performance units	2,415,321	5,098,110	5,746,661
Weighted-average shares outstanding diluted	271,275,849	269,166,290	269,166,005

(8) Inventories

Inventories consisted of the following:

	December 31,	
	2008	2007
	(Dollars in millions)	
Materials and supplies	$ 110.2	$ 90.2

Raw coal	24.0	45.5
Saleable coal	143.5	129.0
Total	$ 277.7	$ 264.7

(9) Leases

The Company leases equipment and facilities under various noncancelable lease agreements. Certain lease agreements require the maintenance of specified ratios and contain restrictive covenants which limit indebtedness, subsidiary dividends, investments, asset sales and other Company actions. Rental expense under

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

operating leases was $108.7 million, $104.7 million and $78.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. The gross value of property, plant, equipment and mine development assets under capital leases was $99.4 million and $116.9 million as of December 31, 2008 and 2007, respectively, related primarily to the leasing of mining equipment. The accumulated amortization for these items was $18.2 million and $24.7 million at December 31, 2008 and 2007, respectively.

The Company also leases coal reserves under agreements that require royalties to be paid as the coal is mined. Certain agreements also require minimum annual royalties to be paid regardless of the amount of coal mined during the year. Total royalty expense was $508.2 million, $343.1 million and $285.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

A substantial amount of the coal mined by the Company is produced from mineral reserves leased from the owner. One of the major lessors is the U.S. government, from which the Company leases substantially all of the coal it mines in Wyoming and Colorado under terms set by Congress and administered by the U.S. Bureau of Land Management. These leases are generally for an initial term of ten years but may be extended by diligent development and mining of the reserves until all economically recoverable reserves are depleted. The Company has met the diligent development requirements for substantially all of these federal leases either directly through production or by including the lease as a part of a logical mining unit with other leases upon which development has occurred. Annual production on these federal leases must total at least 1.0% of the original amount of coal in the entire logical mining unit. In addition, royalties are payable monthly at a rate of 12.5% of the gross realization from the sale of the coal mined using surface mining methods and at a rate of 8.0% of the gross realization for coal produced using underground mining methods. The Company also leases coal reserves in Arizona from The Navajo Nation and the Hopi Tribe under leases that are administered by the U.S. Department of the Interior. These leases expire upon exhaustion of the leased reserves or upon the permanent ceasing of all mining activities on the related reserves as a whole. The royalty rates are also generally based upon a percentage of the gross realization from the sale of coal. These rates are subject to redetermination every ten years under the terms of the leases. The remainder of the leased coal is generally leased from state governments, land holding companies and various individuals. The duration of these leases varies greatly. Typically, the lease terms are automatically extended as long as active mining continues. Royalty payments are generally based upon a specified rate per ton or a percentage of the gross realization from the sale of the coal.

Future minimum lease and royalty payments as of December 31, 2008, are as follows:

Year Ended December 31,	Capital Leases	Operating Leases	Coal Lease and Royalty Obligations
		(Dollars in millions)	
2009	$ 19.1	$ 76.3	$ 134.1
2010	15.1	73.3	8.0
2011	15.1	59.2	7.1
2012	15.1	41.2	6.2
2013	23.0	32.4	5.3

2014 and thereafter	12.0	126.8	33.2
Total minimum lease payments	$ 99.4	$ 409.2	$ 193.9
Less interest	18.2		
Present value of minimum capital lease payments	$ 81.2		

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2008, certain of the Company s lease obligations were secured by outstanding surety bonds totaling $99.2 million.

(10) Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consisted of the following:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Trade accounts payable	$ 427.9	$ 393.5
Accrued taxes other than income	170.7	152.2
Accrued payroll and related benefits	120.1	76.1
Accrued health care	82.5	83.5
Workers compensation obligations	8.7	6.2
Other accrued benefits	4.1	3.1
Accrued royalties	77.7	35.4
Accrued environmental	7.6	7.1
Income taxes payable Australia	142.7	27.6
Accrued interest	31.1	30.9
Other accrued expenses	131.7	131.8
Commodity and foreign currency hedge contracts	261.1	1.5
Liabilities associated with discontinued operations	69.1	180.4
Current liabilities associated with assets held for sale		4.7
Total accounts payable and accrued expenses	$ 1,535.0	$ 1,134.0

(11) Income Taxes

Income from continuing operations before income taxes and minority interests consisted of the following:

	Year Ended December 31, 2008	2007	2006
	(Dollars in millions)		
U.S.	$ 186.1	$ 297.0	$ 235.3
Non U.S.	990.7	67.8	249.5
Total	$ 1,176.8	$ 364.8	$ 484.8

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Total income tax provision (benefit) consisted of the following:

	Year Ended December 31, 2008	2007	2006
	(Dollars in millions)		
Current:			
U.S. federal	$	$	$ 4.3
Non U.S.	218.7	26.4	67.6
State		0.2	0.4
Total current	218.7	26.6	72.3
Deferred:			
U.S. federal	47.5	(136.5)	(161.0)
Non U.S.	(81.7)	44.2	4.1
State	1.3	(7.2)	(1.1)
Total deferred	(32.9)	(99.5)	(158.0)
Total provision (benefit)	$ 185.8	$ (72.9)	$ (85.7)

The income tax rate differed from the U.S. federal statutory rate as follows:

	Year Ended December 31, 2008	2007	2006
	(Dollars in millions)		
Federal statutory rate	$ 411.9	$ 127.7	$ 169.7
Excess depletion	(40.1)	(55.3)	(52.3)
Foreign earnings rate differential	(124.4)	(17.3)	(20.4)
Remeasurement of foreign deferred taxes	(65.2)	56.0	
State income taxes, net of U.S. federal tax benefit	(1.6)	0.8	5.6
Tax credits	(12.6)	(24.3)	
Changes in valuation allowance	(44.2)	(175.7)	(165.5)
Changes in tax reserves	34.4	3.3	(28.7)
Other, net	27.6	11.9	5.9
Total provision (benefit)	$ 185.8	$ (72.9)	$ (85.7)

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities consisted of the following:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Deferred tax assets:		
Tax credits and loss carryforwards	$ 785.9	$ 680.9
Postretirement benefit obligations	403.9	350.1
Intangible tax asset and purchased contract rights	58.1	83.6
Accrued reclamation and mine closing liabilities	46.2	32.4
Accrued long-term workers compensation liabilities	12.6	15.6
Employee benefits	56.2	35.9
Financial guarantee	23.8	24.4
Others	56.5	39.5
Total gross deferred tax assets	1,443.2	1,262.4
Deferred tax liabilities:		
Property, plant, equipment and mine development, leased coal interests and advance royalties, principally due to differences in depreciation, depletion and asset writedowns	1,154.2	1,357.8
Hedge activities	35.3	43.1
Investments and other assets	76.6	64.9
Total gross deferred tax liabilities	1,266.1	1,465.8
Valuation allowance	(57.0)	(92.6)
Net deferred tax asset (liability)	$ 120.1	$ (296.0)
Deferred taxes are classified as follows:		
Current deferred income taxes	$ 1.7	$ 58.8
Noncurrent deferred income taxes	118.4	(354.8)
Net deferred tax asset (liability)	$ 120.1	$ (296.0)

The Company s tax credits and loss carryforwards included alternative minimum tax (AMT) and general business credits of $62.4 million and $49.8 million, U.S. NOL carryforwards of $653.5 million and $574.3 million and foreign loss carryforwards of $70.0 million and $56.8 million as of December 31, 2008 and 2007, respectively. The AMT credits and foreign NOL and capital loss carryforwards have no expiration date and the U.S. NOL carryforwards begin to expire in the year 2020. The Company evaluated and assessed the expected near-term utilization of NOLs, future book and taxable income, available tax strategies and the overall deferred tax position to determine the appropriate amount and timing of valuation allowance adjustments. The largest component of the 2008 assessment was a $45.3 million reduction of a valuation allowance on foreign NOL s. Significant reductions of valuation allowance on U.S. NOL carryforwards arose during the 2007 and 2006 assessments. The remaining valuation allowance at December 31, 2008 of $57.0 million represents a reserve for AMT credits, certain foreign deferred tax assets and state loss carryforwards due to uncertainty of their ultimate realization.

The total amount of the net unrecognized tax benefits was $176.9 million ($186.3 million gross) at December 31, 2008 and was $143.2 million ($152.6 million gross) at December 31, 2007. The amount of the Company s gross unrecognized tax benefits has increased by $33.7 million since January 1, 2008. A

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

reconciliation of the beginning and ending amount of gross unrecognized tax benefits is as follows (dollars in millions):

Balance at Janaury 1, 2008	$ 152.6
Additions based on tax positions related to current year	30.3
Addidtions to tax positions of prior years	3.4
Balance at December 31, 2008	$ 186.3

The amount of the net unrecognized tax benefits that, if recognized, would directly affect the effective tax rate is $176.9 million. However, $27.0 million would generate a deferred tax asset for state NOL carryforwards that would more likely than not be offset by a valuation allowance. The Company does not expect any significant changes to its net unrecognized tax benefits within 12 months of this reporting date.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in its income tax provision. The Company has recognized $1.3 million of interest for the year ended December 31, 2008. The Company had $3.6 million and $2.3 million of accrued interest related to uncertain tax positions at December 31, 2008 and 2007, respectively. The Company has considered the application of penalties on its unrecognized tax benefits and determined, based upon several factors, including the existence of NOL carryforwards, that no accrual of penalties is required.

The Company s federal income tax returns for the tax years 2005 and 2006 are currently under examination by the IRS while the Company s federal income tax returns for 1999 through 2001, 2003 through 2004 and 2007 through 2008 remain subject to examination by the IRS. The Company s state income tax returns for the tax years 1991 and beyond remain subject to examination by various state taxing authorities. The Company s foreign income tax returns for the tax years 2003 and beyond remain subject to examination by various foreign taxing authorities.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $1.2 billion at December 31, 2008 and $303.6 million at December 31, 2007. The Company has not provided deferred taxes on foreign earnings of $1.1 billion for 2008 and of $264.5 million for 2007 because such earnings were intended to be indefinitely reinvested outside the U.S. Should the Company repatriate all of these earnings, a one-time income tax charge to the Company s consolidated results of operations of up to $387.0 million could occur.

The following table summarizes the Company s tax payments:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(Dollars in millions)		
U.S. federal	$	$ 3.0	$ 3.9
U.S. state and local		1.2	0.5

Non U.S	65.8	80.0	23.1
Total tax payments	$ 65.8	$ 84.2	$ 27.5

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) Long-Term Debt

The Company s total indebtedness as of December 31, 2008 and 2007, consisted of the following:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Term Loan under Senior Unsecured Credit Facility	$ 490.3	$ 509.1
Revolving Credit Facility		97.7
Convertible Junior Subordinated Debentures due 2066	732.5	732.5
7.375% Senior Notes due 2016	650.0	650.0
6.875% Senior Notes due 2013	650.0	650.0
7.875% Senior Notes due 2026	247.0	247.0
5.875% Senior Notes due 2016	218.1	218.1
6.84% Series C Bonds due 2016	43.0	43.0
6.34% Series B Bonds due 2014	18.0	21.0
6.84% Series A Bonds due 2014	10.0	10.0
Capital lease obligations	81.2	92.2
Fair value hedge adjustment	15.1	1.6
Other	1.0	0.9
Total	$ 3,156.2	$ 3,273.1

Senior Unsecured Credit Facility

On September 15, 2006, the Company entered into a Third Amended and Restated Credit Agreement (the Agreement), which established a $2.75 billion Senior Unsecured Credit Facility (the Senior Unsecured Credit Facility) and which amended and restated in full the Company s then existing $1.35 billion Senior Secured Credit Facility (the Senior Secured Credit Facility). The Senior Unsecured Credit Facility provides a $1.8 billion Revolving Credit Facility (the Revolver) and a $950.0 million Term Loan Facility (the Term Loan Facility).

The Revolver is intended to accommodate working capital needs, letters of credit, and other general corporate purposes. The Revolver also includes a $50.0 million sub-facility available for same-day swingline loan borrowings. As of December 31, 2008, the Company had no borrowings and $245.1 million letters of credit outstanding under the Revolver, with a remaining available borrowing capacity of $1.5 billion.

The Term Loan Facility, which was fully drawn in October 2006 in connection with the Excel Coal Limited (Excel) acquisition was paid down ($403.0 million) from a portion of the net proceeds from the Convertible Junior Subordinated Debentures due 2066 (the Debentures). In conjunction with the establishment of the Senior Unsecured Credit Facility, the Company incurred $8.6 million in financing costs, of which $5.6 million related to the Revolver and $3.0 million related to the Term Loan. These debt issuance costs are being amortized to interest expense over five years, the term of the Senior Unsecured Credit Facility.

Loans under the facility are available to the Company in U.S. dollars, with a sub-facility under the Revolver available in Australian dollars, pounds sterling and euros. Letters of credit under the Revolver are available to the Company in U.S. dollars with a sub-facility available in Australian dollars, pounds sterling and euros. The interest rate payable on the Revolver and the Term Loan is based on a pricing grid tied to the Company s leverage ratio, as defined in the Agreement. The interest rate payable on the Revolver and the Term Loan is currently LIBOR plus 0.75%, which was 2.2% at December 31, 2008.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Under the Senior Unsecured Credit Facility, the Company must comply with certain financial covenants on a quarterly basis including a minimum interest coverage ratio and a maximum leverage ratio, as defined in the Agreement. The financial covenants also place limitations on the Company s investments in joint ventures, unrestricted subsidiaries, indebtedness of non-loan parties and the imposition of liens on Company assets. The new facility is less restrictive with respect to limitations on the Company s dividend payments, capital expenditures, asset sales and stock repurchases. The Senior Unsecured Credit Facility matures on September 15, 2011.

Convertible Junior Subordinated Debentures

As of December 31, 2008, the Company had $732.5 million aggregate principal of 4.75% Convertible Junior Subordinated Debentures outstanding, which are due 2066, including $57.5 million issued pursuant to the underwriters exercise of their over-allotment option. The Debentures generally require interest to be paid semiannually at a rate of 4.75% per year. The Company may elect to, and to the extent that a mandatory trigger event (as defined in the indenture governing the Debentures) has occurred and is continuing will be required to, defer interest payments on the Debentures. After five years of deferral at the Company s option, or upon the occurrence of a mandatory trigger event, the Company generally must sell warrants or preferred stock with specified characteristics and use the funds from that sale to pay deferred interest, subject to certain limitations. In no event may the Company defer payments of interest on the Debentures for more than 10 years.

The Debentures are convertible at any time on or prior to December 15, 2036 if any of the following conditions occur: (i) the Company s closing common stock price exceeds 140% of the then applicable conversion price for the Debentures (currently $81.81 per share) for at least 20 of the final 30 trading days in any quarter; (ii) a notice of redemption is issued with respect to the Debentures; (iii) a change of control, as defined in the indenture governing the Debentures; (iv) satisfaction of certain trading price conditions; and (v) other specified corporate transactions described in the indenture governing the Debentures. In addition, the Debentures are convertible at any time after December 15, 2036 to December 15, 2041, the scheduled maturity date. In the case of conversion following a notice of redemption or upon a non-stock change of control, as defined in the indenture governing the Debentures, holders may convert their Debentures into cash in the amount of the principal amount of their Debentures and shares of the Company s common stock for any conversion value in excess of the principal amount. In all other conversion circumstances, holders will receive perpetual preferred stock (see Note 16) with a liquidation preference equal to the principal amount of their Debentures, and any conversion value in excess of the principal amount will be settled with the Company s common stock. As a result of the Patriot spin-off, the conversion rate was adjusted. The current conversion rate is 17.1125 shares of common stock per $1,000 principal amount of Debentures effective November 23, 2007. This adjusted conversion rate represents a conversion price of approximately $58.44.

The Debentures are not subject to redemption prior to December 20, 2011. Between December 20, 2011 and December 19, 2036 the Company may redeem the Debentures, in whole or in part, if for at least 20 out of the 30 consecutive trading days immediately prior to the date on which notice of redemption is given, the Company s closing common stock price has exceeded 130% of the then applicable conversion price for the Debentures. On or after December 20, 2036, whether or not the redemption condition is satisfied, the Company may redeem the Debentures, in whole or in part. The Company may not redeem any Debentures unless (i) all accrued and unpaid interest on the Debentures has been paid in full on or prior to the redemption date and (ii) if any perpetual preferred stock is outstanding, the Company has first given notice to redeem the perpetual preferred stock in the same proportion as the redemption of the Debentures. Any redemption of the Debentures will be at a cash redemption price of 100% of the principal amount of the Debentures to be redeemed, plus accrued and unpaid interest to the date of redemption.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On December 15, 2041, the scheduled maturity date, the Company will use commercially reasonable efforts, subject to the occurrence of a market disruption event, as defined in the indenture governing the Debentures, to issue securities of equivalent equity content in an amount sufficient to pay the principal amount of the Debentures, together with accrued and unpaid interest. The final maturity date of the Debentures is December 15, 2066, on which date the entire principal amount of the Debentures will mature and become due and payable, together with accrued and unpaid interest.

In connection with the issuance of the Debentures, the Company entered into a Capital Replacement Covenant (the CRC). Pursuant to the CRC, the Company covenanted for the benefit of holders of covered debt, as defined in the CRC (currently the Company s 7.875% Senior Notes due 2026, issued in the aggregate principal amount of $250.0 million), that neither the Company nor any of its subsidiaries shall repay, redeem or repurchase all or any part of the Debentures on or after December 15, 2041 and prior to December 15, 2046, except to the extent that the total repayment, redemption or repurchase price does not exceed the sum of: (i) 400% of the Company s net cash proceeds from the sale of its common stock and rights to acquire its common stock (including common stock issued pursuant to the Company s dividend reinvestment plan or employee benefit plans); (ii) the Company s net cash proceeds from the sale of its mandatorily convertible preferred stock, as defined in the CRC, or debt exchangeable for equity, as defined in the CRC; and (iii) the Company s net cash proceeds from the sale of other replacement capital securities, as defined in the CRC, in each case, during the six months prior to the notice date for the relevant payment, redemption or repurchase.

The Debentures are unsecured obligations of the Company, ranking junior to all existing and future senior and subordinated debt (excluding trade accounts payable or accrued liabilities arising in the ordinary course of business) except for any future debt that ranks equal to or junior to the Debentures. The Debentures will rank equal in right of payment with the Company s obligations to trade creditors. Substantially all of the Company s existing indebtedness is senior to the Debentures. In addition, the Debentures will be effectively subordinated to all indebtedness of the Company s subsidiaries. The indenture governing the Debentures places no limitation on the amount of additional indebtedness that the Company or any of the Company s subsidiaries may incur.

7.375% Senior Notes Due November 2016 and 7.875% Senior Notes Due November 2026

As of December 31, 2008, the Company had $650.0 million of 7.375% 10-year Senior Notes outstanding, which are due 2016 and $250.0 million of 7.875% 20-year Senior Notes outstanding, which are due 2026. The notes are general unsecured obligations of the Company and rank senior in right of payment to any subordinated indebtedness of the Company; equally in right of payment with any senior indebtedness of the Company; effectively junior in right of payment to the Company s existing and future secured indebtedness, to the extent of the value of the collateral securing that indebtedness; and effectively junior to all the indebtedness and other liabilities of the Company s subsidiaries that do not guarantee the notes. Interest payments are scheduled to occur on May 1 and November 1 of each year. The first interest payment occurred on May 1, 2007.

The notes are guaranteed by the Company s Subsidiary Guarantors, as defined in the note indenture. The note indenture contains covenants that, among other things, limit the Company s ability to create liens and enter into sale and lease-back transactions. The notes are redeemable at a redemption price equal to 100% of the principal amount of the notes being redeemed plus a make-whole premium, if applicable, and any accrued unpaid interest to the redemption date. Net proceeds from the offering, after deducting underwriting discounts and expenses, were

$886.1 million.

6.875% Senior Notes Due March 2013

At December 31, 2008, the Company had $650.0 million of 6.875% Senior Notes outstanding, which are due March 2013. The notes are senior unsecured obligations of the Company and rank equally with all of the

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PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on March 15 and September 15 of each year. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable at fixed redemption prices as set forth in the indenture.

5.875% Senior Notes Due March 2016

As of December 31, 2008, the Company had $218.1 million of 5.875% Senior Notes outstanding, which are due March 2016. The notes are senior unsecured obligations of the Company and rank equally with all of the Company s other senior unsecured indebtedness. Interest payments are scheduled to occur on April 15 and October 15 of each year, and commenced on April 15, 2004. The notes are guaranteed by the Company s Subsidiary Guarantors as defined in the note indenture. The note indenture contains covenants which, among other things, limit the Company s ability to incur additional indebtedness and issue preferred stock, pay dividends or make other distributions, make other restricted payments and investments, create liens, sell assets and merge or consolidate with other entities. The notes are redeemable prior to April 15, 2009, at a redemption price equal to 100% of the principal amount plus a make-whole premium (as defined in the indenture) and on or after April 15, 2009, at fixed redemption prices as set forth in the indenture. Net proceeds from the offering, after deducting underwriting discounts and expenses, were $244.7 million.

Series Bonds

As of December 31, 2008, the Company had $71.0 million in Series Bonds outstanding, which were assumed as part of the Excel acquisition. The 6.84% Series A Bonds have a balloon maturity in December 2014. The 6.34% Series B Bonds mature in December 2014 and are payable in installments with the first scheduled payment made in December 2008. The 6.84% Series C Bonds mature in December 2016 and are payable in installments beginning December 2012. Interest payments are scheduled to occur in June and December of each year.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Interest Rate Swaps

As of December 31, 2008, the Company had a series of fixed-to-floating (fair value hedges) and floating-to-fixed interest rate swaps. The following table details the swaps:

	Notional Amount	Benefit Received	Amount Paid (Dollars in millions)	Termination Date	Fair Value
Fixed to Floating					
67/8 $650M Senior Notes	$ 120.0	6.875% semi-annually	3M LIBOR + 196.9 bps quarterly	3/15/2013	$ 6.0
67/8 $650M Senior Notes	$ 25.0	6.875% semi-annually	6M LIBOR + 299.75 bps semi-annually	3/15/2013	$ 0.8
67/8 $650M Senior Notes	$ 25.0	6.875% semi-annually	6M LIBOR + 307 bps semi-annually	3/15/2013	$ 0.8
67/8 $650M Senior Notes	$ 25.0	6.875% semi-annually	6M LIBOR + 316 bps semi-annually	3/15/2013	$ (0.5)
67/8 $650M Senior Notes	$ 25.0	6.875% semi-annually	6M LIBOR + 307.5 bps semi-annually	3/15/2013	$ 0.8
57/8 $250M Senior Note	$ 100.0	5.875% semi-annually	6M LIBOR + 25.3 bps semi-annually	4/15/2016	$ 4.6
Floating to Fixed					
Senior Unsecured Term Loan A	$ 120.0	3M LIBOR + 100 bps quarterly	6.25% semi-annually	9/15/2011	$ (12.8)
Shovel Construction Financing	$ 22.0	3M LIBOR quarterly	4.812% semi-annually	7/1/2014	$ (4.0)
Shovel Construction Financing	$ 22.0	3M LIBOR quarterly	4.6525% semi-annually	8/26/2014	$ (2.5)
Shovel Construction Financing	$ 22.0	3M LIBOR quarterly	4.758% semi-annually	12/29/2014	$ (2.5)

Legend: M = millions; bps = basis points

In addition, the Company had three additional swaps, with a combined notional amount of $200.0 million that were terminated during the first half of 2008. The combined settlement amount of $6.9 million was recorded as an adjustment to the fair value hedge adjustment and will be amortized to interest expense over the remaining maturity period of the 6.875% Senior Notes.

Because the critical terms of the swaps and the respective debt instruments they hedge coincide, there was no hedge ineffectiveness recognized in the consolidated statements of operations during the years ended December 31, 2008 and 2007. At December 31, 2007 there was a net unrealized gain on the fair value hedges of $1.6 million. The fair value hedge is reflected as an adjustment to the carrying value of the 5.875% and 6.875% Senior Notes.

Capital Lease Obligations and Other

Capital lease obligations include obligations assumed from the Excel acquisition, primarily for mining equipment (see Note 9 for additional information on the Company s capital lease obligations).

Other long-term debt, which consists principally of notes payable, is due in installments through 2016. The weighted-average effective interest rate of this debt was 5.59% as of December 31, 2008.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The aggregate amounts of long-term debt maturities subsequent to December 31, 2008, including capital lease obligations, were as follows (Dollars in millions):

Year of Maturity	
2009	$ 17.0
2010	14.2
2011	505.0
2012	23.9
2013	706.6
2014 and thereafter	1,889.5
Total	$ 3,156.2

Interest paid on long-term debt was $226.0 million, $191.9 million and $114.6 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Company paid interest expense of $5.8 million, $1.5 million and $3.3 million on the Revolver in 2008, 2007 and 2006.

Shelf Registration Statement

On July 28, 2006, the Company filed an automatic shelf registration statement on Form S-3 as a well-known seasoned issuer with the Securities and Exchange Commission. The registration was for an indeterminate number of securities and is effective for three years, at which time the Company expects to be able to file an automatic shelf registration statement that would become immediately effective for another three-year term. Under this universal shelf registration statement, the Company has the capacity to offer and sell from time to time securities, including common stock, preferred stock, debt securities, warrants and units. The Debentures, 7.375% Senior Notes due 2016 and 7.875% Senior Notes due 2026 were issued pursuant to the shelf registration statement.

(13) Asset Retirement Obligations

Reconciliations of the Company s asset retirement obligation liability are as follows:

	December 31,	
	2008	2007
	(Dollars in millions)	
Balance at beginning of year, including discontinued operations	$ 362.8	$ 418.8
Liabilities incurred or acquired		27.0
Liabilities settled or disposed	(6.4)	(16.2)
Accretion expense	20.5	27.5
Revisions to estimates	45.7	29.6

Consolidated asset retirement obligations	422.6	486.7
Liabilities related to the Patriot spin-off		(123.9)
Balance at end of year	$ 422.6	$ 362.8
Balance at end of year active locations	$ 387.2	$ 331.9
Balance at end of year closed or inactive locations	$ 35.4	$ 30.9

The credit-adjusted, risk-free interest rates were 7.91% at December 31, 2008 and 7.85% and 6.60% at January 1, 2008 and 2007, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2008 and 2007, the Company had $740.6 million and $418.3 million, respectively, in surety bonds outstanding to secure reclamation obligations or activities. The amount of reclamation self-bonding in certain states in which the Company qualifies was $773.4 million and $640.6 million as of December 31, 2008 and 2007, respectively. Additionally, the Company had $0.1 million and $1.6 million of letters of credit in support of reclamation obligations or activities as of December 31, 2008 and 2007, respectively.

(14) Pension and Savings Plans

One of the Company s subsidiaries, Peabody Investments Corp. (PIC), sponsors a defined benefit pension plan covering certain U.S. salaried employees and eligible hourly employees at certain PIC subsidiaries (the Peabody Plan). A PIC subsidiary also has a defined benefit pension plan covering eligible employees who are represented by the UMWA under the Western Surface Agreement (the Western Plan). PIC also sponsors an unfunded supplemental retirement plan to provide senior management with benefits in excess of limits under the federal tax law.

During the period ended March 31, 1999, the Company made an amendment to phase out the Peabody Plan. Effective January 1, 2001, certain employees no longer accrue future service under the plan while other employees accrue reduced service under the plan based on their age and years of service as of December 31, 2000. For plan benefit calculation purposes, employee earnings are also frozen as of December 31, 2000. The Company has adopted an enhanced savings plan contribution structure in lieu of benefits formerly accrued under the defined benefit pension plan.

Annual contributions to the plans are made as determined by consulting actuaries based upon the Employee Retirement Income Security Act of 1974 minimum funding standard. In May 1998, the Company entered into an agreement with the Pension Benefit Guaranty Corporation (PBGC) which requires the Company to maintain certain minimum funding requirements. Beginning on January 1, 2008, new minimum funding standards were required by the Pension Protection Act of 2006. Assets of the plans are primarily invested in various marketable securities, including U.S. government bonds, corporate obligations and listed stocks.

Net periodic pension costs included the following components:

	Year Ended December 31,		
	2008	2007	2006
	(Dollars in millions)		
Service cost for benefits earned	$ 2.0	$ 12.7	$ 12.2
Interest cost on projected benefit obligation	51.0	49.0	46.0
Expected return on plan assets	(60.6)	(57.4)	(54.6)
Amortization of prior service cost	1.3	0.4	
Amortization of actuarial (gains) losses	(0.5)	15.3	22.7
Net periodic pension costs	(6.8)	20.0	26.3
Curtailment gain	(0.6)	(0.4)	

Total net periodic pension (benefit) cost	$ (7.4)	$ 19.6	$ 26.3

In 2007, benefits were frozen for certain participants of the Company s Western U.S. Mining operations and those participants impacted by the Patriot spin-off under the Peabody Plan resulting in actuarially determined curtailment gains of $0.6 million and $0.4 million for the years ended December 31, 2008 and 2007, respectively.

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following includes amounts recognized in accumulated other comprehensive income:

	Year Ended December 31, 2008 (Dollars in millions)
Net actuarial loss arising during year	$ 199.2
Amortizations:	
Actuarial gain	0.5
Prior service cost/curtailment	(0.7)
Total recognized in other comprehensive income	199.0
Net periodic pension costs	(6.8)
Total recognized in net periodic pension costs and other comprehensive income	$ 192.2

The Company amortizes actuarial gains and losses using a 5% corridor with a five-year amortization period. The estimated net actuarial gain and prior service cost that will be amortized from accumulated other comprehensive income (loss) into net periodic pension costs during the year ended December 31, 2009 are $1.7 million and $1.4 million, respectively.

The following summarizes the change in benefit obligation, change in plan assets and funded status of the Company s plans:

	December 31, 2008	December 31, 2007
	(Dollars in millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$ 778.2	$ 832.8
Service cost	2.0	12.7
Interest cost	51.0	49.0
Plan amendments		7.9
Curtailments		(20.5)
Benefits paid	(46.7)	(42.6)
Actuarial gain	(15.9)	(61.1)
Projected benefit obligation at end of period	768.6	778.2
Change in plan assets:		
Fair value of plan assets at beginning of period	732.4	704.2

Actual return on plan assets	(154.4)	65.4
Employer contributions	21.3	5.4
Benefits paid	(46.7)	(42.6)
Fair value of plan assets at end of period	552.6	732.4
Funded status at end of year	(216.0)	(45.8)
Amounts recognized in the consolidated balance sheets:		
Intangible asset (included in Investments and other assets)		0.2
Current obligation (included in Accounts payable and accrued expenses)	(1.6)	(1.3)
Noncurrent obligation (included in Other noncurrent liabilities)	(214.4)	(44.7)
Net amount recognized	$ (216.0)	$ (45.8)

PEABODY ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted-average assumptions used to determine the benefit obligations as of the end of each year were as follows: