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

FORM 10-K

(Mark One)

☒ 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

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

For the transition period from to

Commission File No. 001-07775

MASSEY ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**95-0740960**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4 North 4th Street, Richmond, Virginia	**23219**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (804) 788-1800

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

Title of each class	Name of each exchange on which registered
Common Stock, $0.625 par value	New York Stock Exchange

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

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

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 ☐ No ☒

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

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

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," "non-accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check One):
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company)
Smaller reporting company ☐

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

The aggregate market value of the common stock held by non-affiliates of the registrant on June 30, 2008, was $7,571,508,750 based on the last sales price reported that date on the New York Stock Exchange of $93.75 per share. In determining this figure, the Registrant has assumed that all of its directors and executive officers are affiliates. Such assumptions should not be deemed to be conclusive for any other purpose.

Common stock, $0.625 par value (“Common Stock”), outstanding as of February 17, 2009 — 85,492,888 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Part III incorporates certain information by reference from the registrant’s definitive proxy statement for the 2009 Annual Meeting of Stockholders, which proxy statement will be filed no later than 120 days after the close of the registrant’s fiscal year ended December 31, 2008.

Forward Looking Statements

From time to time, Massey Energy Company, which includes its direct and wholly owned subsidiary, A. T. Massey Coal Company, Inc, and its direct and indirect wholly owned subsidiaries ("we," "our," "us"), makes certain comments and disclosures in reports, including this report, or through statements made by our officers that may be forward-looking in nature. Examples include statements related to our future outlook, anticipated capital expenditures, projected cash flows and borrowings and sources of funding. We caution readers that forward-looking statements, including disclosures that use words such as "believe," "anticipate," "expect," "estimate," "intend," "may," "plan," "project," "will" and similar words or statements are subject to certain risks, trends and uncertainties that could cause actual cash flows, results of operations, financial condition, cost reductions, acquisitions, dispositions, financing transactions, operations, expansion, consolidation and other events to differ materially from the expectations expressed or implied in such forward-looking statements. Any forward-looking statements are also subject to a number of assumptions regarding, among other things, future economic, competitive and market conditions. These assumptions are based on facts and conditions, as they exist at the time such statements are made as well as predictions as to future facts and conditions, the accurate prediction of which may be difficult and involve the assessment of circumstances and events beyond our control. We disclaim any intent or obligation to update these forward-looking statements unless required by securities law, and we caution the reader not to rely on them unduly.

We have based any forward-looking statements we have made on our current expectations and assumptions about future events and circumstances that are subject to risks, uncertainties and contingencies that could cause results to differ materially from those discussed in the forward-looking statements, including, but not limited to:

(i) our cash flows, results of operation or financial condition;
(ii) the successful completion of acquisition, disposition or financing transactions and the effect thereof on our business;
(iii) governmental policies, laws, regulatory actions and court decisions affecting the coal industry or our customers' coal usage;
(iv) legal and administrative proceedings, settlements, investigations and claims and the availability of insurance coverage related thereto;
(v) inherent risks of coal mining beyond our control, including weather and geologic conditions or catastrophic weather-related damage;
(vi) our production capabilities to meet market expectations and customer requirements;
(vii) our ability to obtain coal from brokerage sources or contract miners in accordance with their contracts;
(viii) our ability to obtain and renew permits necessary for our existing and planned operations in a timely manner;
(ix) the cost and availability of transportation for our produced coal;
(x) our ability to expand our mining capacity;
(xi) our ability to manage production costs, including labor costs;
(xii) adjustments made in price, volume or terms to existing coal supply agreements;
(xiii) the worldwide market demand for coal, electricity and steel;
(xiv) environmental concerns related to coal mining and combustion and the cost and perceived benefits of alternative sources of energy such as natural gas and nuclear energy;
(xv) competition among coal and other energy producers, in the United States and internationally;
(xvi) our ability to timely obtain necessary supplies and equipment;
(xvii) our reliance upon and relationships with our customers and suppliers;
(xviii) the creditworthiness of our customers and suppliers;
(xix) our ability to attract, train and retain a skilled workforce to meet replacement or expansion needs;
(xx) our assumptions and projections concerning economically recoverable coal reserve estimates;
(xxi) our failure to enter into anticipated new contracts;
(xxii) future economic or capital market conditions;
(xxiii) foreign currency fluctuations;
(xxiv) the availability and costs of credit, surety bonds and letters of credit that we require;
(xxv) the lack of insurance against all potential operating risks;
(xxvi) our assumptions and projections regarding pension and other post-retirement benefit liabilities;
(xxvii) our interpretation and application of accounting literature related to mining specific issues; and
(xxviii) the successful implementation of our strategic plans and objectives for future operations and expansion or consolidation.

We are including this cautionary statement in this document to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf, of us. Any forward-looking statements should be considered in context with the various disclosures made by us about our businesses, including without limitation the risk factors more specifically described below in Item 1A. Risk Factors of this Annual Report on Form 10-K.

2008 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

Annual Shareholders Meeting

Our 2009 Annual Meeting of Shareholders will be held at 9:00 a.m. EDT on Tuesday, May 19, 2009 at The Jefferson Hotel, 101 West Franklin Street, Richmond, Virginia 23220.

Part I

Because certain terms used in the coal industry may be unfamiliar to many investors, we have provided a Glossary of Selected Terms beginning on page 19 at the end of Item 1. Business.

Item 1. Business

Business Overview

We are one of the premier coal producers in the United States. In terms of produced coal revenue in 2007, we are the fourth largest United States coal company in terms of produced coal revenue, according to Energy Ventures Analysis, Inc. ("EVA"). According to EVA, we are the largest coal company in Central Appalachia, our primary region of operation, in terms of tons produced and total coal reserves in 2007.

We produce, process and sell bituminous coal of various steam and metallurgical grades, primarily of a low sulfur content, through our 23 processing and shipping centers ("Resource Groups"), many of which receive coal from multiple mines. At January 31, 2009, we operated 66 mines, including 46 underground mines (two of which employ both room and pillar and longwall mining) and 20 surface mines (with eleven highwall miners in operation) in West Virginia, Kentucky and Virginia. The number of mines that we operate may vary from time to time depending on a number of factors, including the existing demand for and price of coal, exhaustion of economically recoverable reserves and availability of experienced labor.

Customers for our steam coal product include primarily electric power utility companies who use our coal as fuel for their steam-powered generators. Customers for our metallurgical coal include primarily steel producers who use our coal to produce coke, which is in turn used as a raw material in the steel manufacturing process.

Key statistics for 2008 include:

- Produced coal revenues increased by 25% from $2.1 billion in 2007 to $2.6 billion in 2008 on produced coal sales of 41.0 million tons.
- Reserve base of approximately 2.3 billion tons at December 31, 2008.

A.T. Massey was originally incorporated in Richmond, Virginia in 1920 as a coal brokering business. In the late 1940s, A.T. Massey expanded its business to include coal mining and processing. In 1974, St. Joe Minerals acquired a majority interest in A.T. Massey. In 1981, St. Joe Minerals was acquired by Fluor Corporation. A.T. Massey was wholly owned by Fluor Corporation from 1987 until November 30, 2000. On November 30, 2000, we completed a reverse spin-off (the "Spin-Off") which separated Fluor Corporation into two entities: the "new" Fluor Corporation ("New Fluor") and Fluor Corporation which retained our coal-related businesses and was subsequently renamed Massey Energy Company. Massey Energy Company has been a separate, publicly traded company since December 1, 2000.

Industry Overview

Coal accounted for 24% of the energy consumed (excluding certain alternative fuels including wind, geothermal and solar power generators) by the United States and 29% of energy consumed globally in 2007, according to the BP Statistical Review of World Energy ("BP"). In 2007, coal was the fuel source of 49% of the electricity generated nationwide, as reported by the Energy Information Administration ("EIA"), a statistical agency of the United States Department of Energy.

According to BP, in 2007, the United States was the second largest coal producer in the world, exceeded only by China. Other leading coal producers include Australia, India, South Africa, the Russian Federation and Indonesia. According to BP, the United States has the largest coal reserves in the world, with proved reserves totaling 243 billion tons. The Russian Federation ranks second in proved coal reserves with 157 billion tons, followed by China with 115 billion tons, according to BP.

United States coal reserves are more plentiful than oil or natural gas with 234 years of supply at current production rates. Proved United States reserves of oil amount to 12 years of supply at current production rates and proved United States reserves of natural gas amount to 11 years of supply at current levels of consumption, as reported by BP.

United States coal production has more than doubled over the last 40 years. In 2008, total United States coal production, as estimated by the EIA, was 1.2 billion tons. The primary producing regions by tons were as follows:

Region	% of Total
Powder River Basin	46%
Central Appalachia	20%
West (other than Powder River Basin)	11%
Northern Appalachia	11%
Midwest	9%
All other	3%
Total	100%

The EIA estimated that approximately 69% of United States coal was produced by surface mining methods in 2007. The remaining 31% was produced by underground mining methods, which include room and pillar mining and longwall mining (more fully described in Item 1. Business, under the heading “Mining Methods”).

Coal is used in the United States by utilities to generate electricity, by steel companies to make steel products, and by a variety of industrial users to produce heat and to power foundries, cement plants, paper mills, chemical plants and other manufacturing and processing facilities. Significant quantities of coal are also exported from both East and Gulf Coast terminals. The breakdown of United States coal consumption for the first ten months of 2008 as estimated by the EIA, is as follows:

End Use	% of Total
Electric Power	93%
Other Industrial	5%
Coke	2%
Residential and Commercial	<1%
Total	100%

Coal has long been favored as an electricity generating fuel because of its basic economic advantage. The largest cost component in electricity generation is fuel. This fuel cost is typically lower for coal than competing fuels such as oil and natural gas on a Btu-comparable basis. The EIA estimates the average cost of various fossil fuels for generating electricity in the first 11 months of 2008 was as follows:

Electricity Generation Source	Average Cost per million BTU
Petroleum Liquids	$ 16.56
Natural Gas	$ 9.34
Coal	$ 2.06
Petroleum Coke	$ 1.85

There are factors other than fuel cost that influence each utility’s choice of electricity generation mode, including facility construction cost, access to fuel transportation infrastructure, environmental restrictions, and other factors. The breakdown of United States electricity generation by fuel source in 2007, as estimated by EIA, is as follows:

Electricity Generation Source	% of Total Electricity Generation
Coal	49%
Natural Gas	21%
Nuclear	19%
Hydroelectric	6%
Oil and other (solar, wind, etc.)	5%
Total	100%

Demand for electricity has historically been driven by United States economic growth but it can fluctuate from year to year depending on weather patterns. In 2008, electricity consumption in the United States decreased 0.4% from 2007, but the average growth rate in the past decade was approximately 1.3% per year according to EIA estimates. Because coal-fired generation is used in most cases to meet base load requirements, coal consumption has generally grown at the pace of electricity demand growth.

According to the World Coal Institute ("WCI"), in 2007 the United States ranked seventh among worldwide exporters of coal. Australia was the largest exporter, with other major exporters including Indonesia, the Russian Federation, Columbia, South Africa and China. According to EVA, United States exports increased by 37% from 2007 to 2008. The usage breakdown for 2008 United States coal exports of 80 million tons was 47% for electricity generation and 53% for steel production. In 2008, United States coal exports were shipped to more than 30 countries. The largest purchaser of United States exported utility coal in 2008 continued to be Canada, which took 19.1 million tons or 50% of total utility coal exports. This was up 31% compared to the 14.6 million tons exported to Canada in 2007. Overall steam coal exports increased 43% in 2008 compared to 2007. The largest purchasers of United States exported metallurgical coal were Brazil, which imported approximately 5.9 million tons, or 14%, and Canada, which imported 3.7 million tons, or 9%. In total, metallurgical coal exports increased 31% in 2008 compared to 2007.

Depending on the relative strength of the United States dollar versus currencies in other coal producing regions of the world, United States producers may export more or less coal into foreign countries as they compete on price with other foreign coal producing sources. Likewise, the domestic coal market may be impacted due to the relative strength of the United States dollar to other currencies, as foreign sources could be cost-advantaged based on a coal producing region's relative currency position.

Since 2003, the global marketplace for coal has experienced swings in the demand/supply balance. In periods of supply shortfall, as occurred from 2003 to early 2006 and again in late 2007 through late 2008, the prices for coal reached record highs in the United States. The increased worldwide demand was primarily driven by higher prices for oil and natural gas and economic expansion, particularly in China, India and elsewhere in Asia. At the same time, infrastructure and regulatory limitations in China contributed to a tightening of worldwide coal supply, affecting global prices of coal. The growth in China and India caused an increase in worldwide demand for raw materials and a disruption of expected coal exports from China to Japan, Korea and other countries. Since mid-2008, the United States and world economies have been in an economic recession and financial credit crisis, significantly reducing the demand for coal.

Metallurgical grade coal is distinguished by special quality characteristics that include high carbon content, volatile matter, low expansion pressure, low sulfur content, and various other chemical attributes. High vol met coal is also high in heat content (as measured in Btus), and therefore is desirable to utilities as fuel for electricity generation. Consequently, high vol met coal producers have the ongoing opportunity to select the market that provides maximum revenue and profitability. The premium price offered by steel makers for the metallurgical quality attributes is typically higher than the price offered by utility coal buyers that value only the heat content. The primary concentration of United States metallurgical coal reserves is located in the Central Appalachian region. EVA estimates that the Central Appalachian region supplied 89% of domestic metallurgical coal and 76% of United States exported metallurgical coal during 2007.

For utility coal buyers, the primary goal is to maximize heat content, with other specifications like ash content, sulfur content, and size varying considerably among different customers. Low sulfur coals, such as those produced in the western United States and in Central Appalachia, generally demand a higher price due to restrictions on sulfur emissions imposed by the Federal Clean Air Act, as amended, and implementing regulations ("Clean Air Act") and the volatility in sulfur dioxide ("SO_2 ") allowance prices that occurred in recent years when the demand for all specifications of coal increased. SO_2 allowances permit utilities to emit a higher level of SO_2 than otherwise required under the Clean Air Act regulations. The demand and premium price for low sulfur coal is expected to diminish as more utilities install scrubbers at their coal-fired plants.

Coal shipped for North American consumption is typically sold at the mine loading facility with transportation costs being borne by the purchaser. Offshore export shipments are normally sold at the ship-loading terminal, with the purchaser paying the ocean freight. According to the National Mining Association ("NMA"), approximately two-thirds of United States coal shipments in recent years were transported via railroads. Final delivery to consumers often involves more than one transportation mode. A significant portion of United States production is delivered to customers via barges on the inland waterway system and ships loaded at Great Lakes ports.

Neither we nor any of our subsidiaries are affiliated with or have any investment in BP, EIA, EVA, Platts or WCI. We are a member of the NMA.

Mining Methods

We produce coal using four distinct mining methods: underground room and pillar, underground longwall, surface and highwall mining, which are explained as follows:

In the underground room and pillar method of mining, continuous miners cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars, or columns of coal, to help support the mine roof and control the flow of air. Generally, openings are driven 20 feet wide and the pillars are 40 to 100 feet wide. As mining advances, a grid-like pattern of entries and pillars is formed. When mining advances to the end of a panel, retreat mining may begin. In retreat mining, as much coal as is feasible is mined from the pillars that were created in advancing the panel, allowing the roof to fall upon retreat. When retreat mining is completed to the mouth of the panel, the mined panel is abandoned.

In longwall mining (which is a type of underground mining), a shearer (cutting head) moves back and forth across a panel of coal typically about 1,000 feet in width, cutting a slice approximately 3.5 feet deep. The cut coal falls onto a flexible conveyor for removal. Longwall mining is performed under hydraulic roof supports (shields) that are advanced as the seam is cut. The roof in the mined out areas falls as the shields advance.

Surface mining is used to extract coal deposits found close to the surface. This method involves removal of overburden (earth and rock covering coal) with heavy earth moving equipment, including large shovels and draglines, and explosives, followed by extraction of coal from coal seams. After extraction of coal, disturbed parcels of land are reclaimed by replacing overburden and reestablishing vegetation and plant life.

Highwall mining is used in connection with surface mining. A highwall mining system consists of a remotely controlled continuous miner, which extracts coal and conveys it via augers or belt conveyors to the portal. The cut is typically a rectangular, horizontal opening in the highwall (the unexcavated face of exposed overburden and coal in a surface mine) 11-feet wide and reaching depths of up to 1,000 feet. Multiple, parallel openings are driven into the highwall, separated by narrow pillars that extend the full depth of the hole.

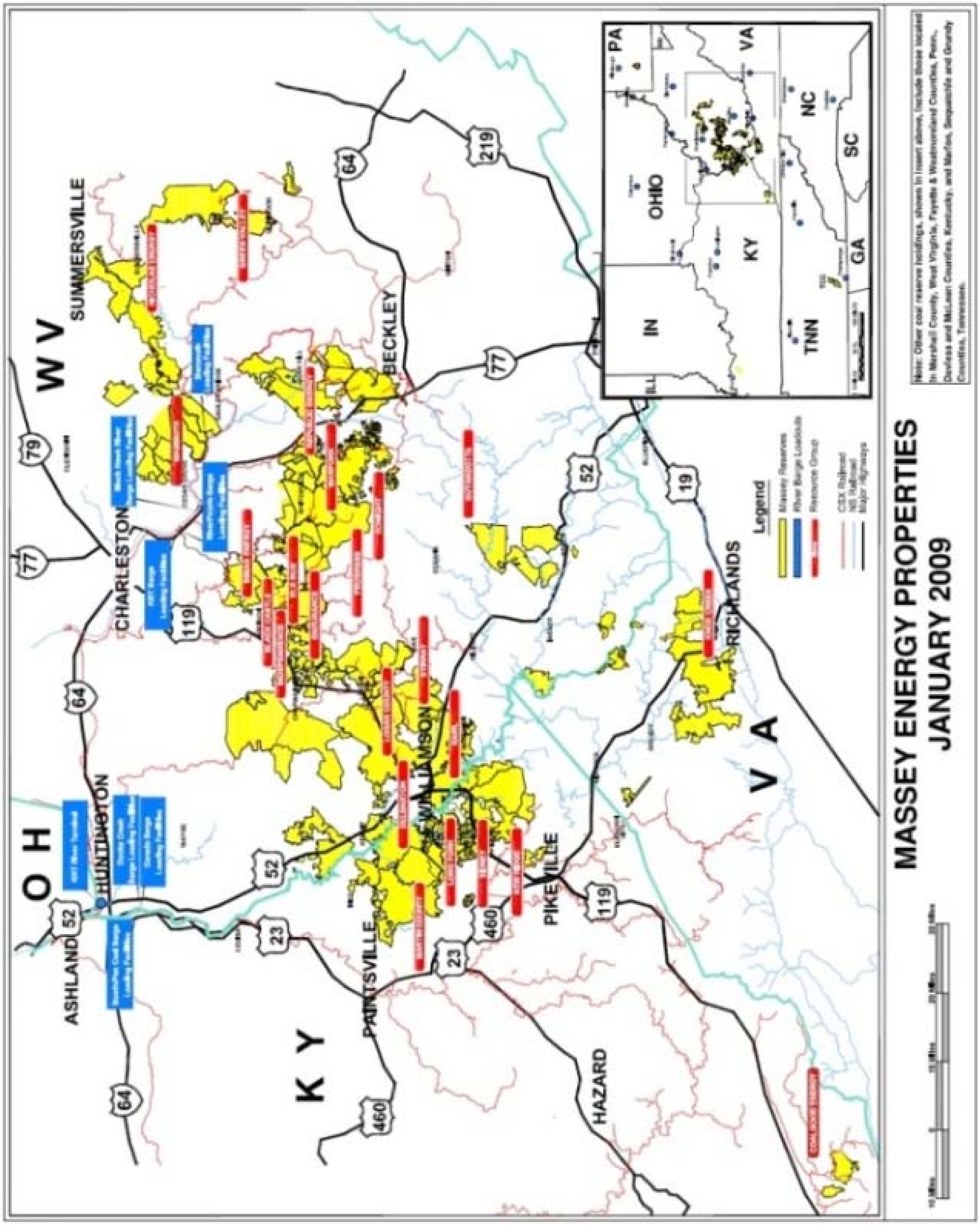
Use of continuous miners in the room and pillar method of underground mining represented approximately 43% of our 2008 coal production. Production from underground longwall mining operations constituted approximately 3% of our 2008 production. Surface mining represented approximately 47% of our 2008 coal production. Surface mines also use highwall mining systems to produce coal from high overburden areas. Highwall mining represented approximately 7% of our 2008 coal production.

Mining Operations

We currently have 23 distinct Resource Groups, including seventeen in West Virginia, five in Kentucky and one in Virginia. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as ten distinct underground or surface mines. Our mines have been developed at strategic locations in close proximity to our preparation plants and rail shipping facilities.

We currently operate solely in the Central Appalachian region, which is the principal source of low sulfur bituminous coal in the United States, used for power generation, metallurgical coke production and industrial boilers. Central Appalachian coal accounted for 20% of 2008 United States coal production according to EIA.

The following map provides the location of our operations within the Central Appalachian region:



The following table provides key operational information on our Resource Groups in 2008:

Resource Group Name	Location (County)	Active/ Inactive	Mine Type	Active Mine Count (1)	Mining Equipment	Transportation	2008 Production (2)	2008 Shipments (3)	Year Established or Acquired
							(Thousands of Tons)		
West Virginia Resource Groups									
Black Castle	Boone	Active	S	1	HW	truck, barge	3,110	1,908	1987
Delbarton	Mingo	Active	U	1		NS	527	776	1999
Edwight	Raleigh	Active	S	1	HW	CSX	1,752	-	2003
Elk Run	Boone	Active	U	5	LW	CSX	2,201	2,796	1978
Endurance	Boone	Active	S	1	HW	CSX	1,127	659	2001
Green Valley	Nicholas	Active	U	3		CSX	727	641	1996
Guyandotte	Wyoming	Active	U	1		NS	146	110	2006
Independence	Boone	Active	U	3	LW	CSX	1,833	3,420	1994
Inman	Boone	Active	U	1		CSX	280	-	2008
Logan County	Logan	Active	S/U	9	HW	CSX	4,651	4,458	1998
Mammoth	Kanawha	Active	U	4		barge	1,233	2,616	2004
Marfork	Raleigh	Active	U	8		CSX	4,043	6,881	1993
Nicholas Energy	Nicholas	Active	S/U	3	HW	NS	3,251	3,081	1997
Progress	Boone	Active	S	1	DL	CSX	5,170	4,177	1998
Rawl	Mingo	Active	U	3		NS	1,000	437	1974
Republic Energy	Raleigh	Active	S	2		truck	2,617	1,210	2004
Stirrat	Logan	Active	S	1		CSX	1,520	1,463	1993
Kentucky Resource Groups									
Coalgood Energy	Harlan	Active	S/U	2	HW	CSX	9	-	2005
Long Fork	Pike	Active				NS	-	1,854	1991
Martin County	Martin	Active	S/U	4		NS	419	236	1969
New Ridge	Pike	Active				CSX	-	261	1992
Sidney	Pike	Active	S/U	10	HW	NS	4,950	3,443	1984
Virginia Resource Group									
Knox Creek	Tazewell	Active	S/U	2	HW	NS	577	536	1997
Total				66			41,143	40,963	

(1) Active mine count as of January 31, 2009.
(2) For purposes of this table, coal production has been allocated to the Resource Group where the coal is mined, rather than the Resource Group where the coal is processed and shipped. Production amounts above represent coal extracted from the ground.
(3) For purposes of this table, coal shipments have been allocated to the Resource Group from where the coal is processed and shipped, rather than the Resource Group where the coal is mined.

S – surface mine
U – underground mine
HW – highwall miners operated in conjunction with surface mines
LW – longwall mine
DL – dragline
NS – Norfolk Southern Railway Company
CSX – CSX Transportation

The following descriptions of the Resource Groups are current as of January 31, 2009.

West Virginia Resource Groups

Black Castle. The Black Castle complex includes a large surface mine, a highwall miner, the Homer III direct-ship loadout, a stoker plant, and the Omar preparation plant. Some of the surface mine coal is trucked to the stoker plant where the coal is crushed and screened. The stoker product is trucked to river docks for barge delivery or trucked directly to customers. A portion of the coal is trucked to the Omar plant, where it is crushed and shipped to customers or, if the coal needs processing, it is belted to the preparation plant at the Independence Resource Group for processing and shipment. The direct-ship facility at the preparation plant can crush 500 tons per hour and the preparation plant can process 800 tons per hour. The Omar preparation plant serves CSX rail system customers with unit train shipments of up to 110 railcars. Coal is also trucked to the Homer III loadout where it is crushed and shipped to customers by rail, trucked to river docks for barge delivery, or trucked directly to customers. The Homer III loadout serves CSX rail system customers with unit train shipments of up to 100 railcars. The Omar preparation plant was not utilized for processing coal in 2008.

Delbarton. The Delbarton complex includes one underground room and pillar mine and a preparation plant. Production from the mine is transported to the Delbarton preparation plant via overland conveyor. The Delbarton preparation plant also processes coal from two surface mines of the Logan County Resource Group. The Delbarton preparation plant can process 600 tons per hour. The clean coal product is shipped to customers via the Norfolk Southern railway in unit trains of up to 110 railcars.

Edwight. The Edwight complex includes a surface mine, a highwall miner and the Goals preparation plant. Production from all of the mines is transported via conveyor system to the Goals preparation plant. The Goals preparation plant can process 800 tons per hour. The rail loading facility serves CSX railway customers with unit trains of up to 100 railcars.

Elk Run. The Elk Run complex produces coal from four underground room and pillar mines and the Logans Fork longwall. All of the room and pillar mines belt coal to the Elk Run preparation plant, while the longwall belts coal to the preparation plant of the Marfork Resource Group. Additionally, Elk Run processes coal produced by surface mines of the Progress Resource Group and transported via underground conveyor system. The Elk Run preparation plant has a processing capacity of 2,200 tons per hour. Elk Run also operates a 200 ton per hour stoker facility that produces screened, small dimension coal for certain of our industrial customers. Customer shipments are loaded on the CSX rail system in unit trains of up to 150 railcars.

Endurance. The Endurance complex includes a surface mine, highwall miner and a direct-ship loadout. A portion of the production from the surface mine is loaded for shipment to customers at the direct ship loadout and the remainder is trucked to the preparation plant at the Independence Resource Group for processing.

Green Valley. The Green Valley complex includes three underground room and pillar mines and a preparation plant. The Green Valley preparation plant, which has a processing capacity of 600 tons per hour, receives coal from the mines via trucks. The rail loading facility services customers on the CSX rail system with unit train shipments of up to 75 railcars.

Guyandotte. The Guyandotte complex includes one underground room and pillar mine. The mine belts coal to a third-party preparation plant for washing and shipment to customers via the Norfolk Southern railway system.

Independence. The Independence complex includes the Revolution longwall mine, two underground room and pillar mines and a preparation plant. Production from the underground mines is transported via overland conveyor system to the Independence preparation plant. The surface mine at the Black Castle Resource Group belts coal and the surface mine at the Endurance Resource Group trucks coal requiring processing to the Independence preparation plant . The Independence plant has a processing capacity of 2,200 tons per hour. Customers are served via rail shipments on the CSX rail system in unit trains of up to 150 railcars.

Inman. The Inman complex includes one underground room and pillar mine and a preparation plant. Production from the underground mine is transported via overland conveyor system to the preparation plant. The Inman plant has a processing capacity of 800 tons per hour. Coal processed at the preparation plant is transported via conveyor belt to Black Castle Resource Group's Homer III loadout, which serves customers via rail shipments on the CSX rail system in unit trains of up to 100 railcars.

Logan County. The Logan County complex includes six surface mines, two highwall miners and three underground room and pillar mines, plus the Bandmill preparation plant and the Feats loadout, all on the CSX rail system. Four surface mines deliver coal to the Bandmill plant via truck and conveyor system, two surface mines truck coal to Edwight Resource Group's Goals preparation plant, and the underground mines belt coal directly to the Bandmill plant. The Feats loadout can service customers via the CSX rail system with unit train shipments of up to 80 cars. The Bandmill preparation plant has a processing capacity of 1,800 tons per hour. The Bandmill rail loading facility services customers via the CSX rail system with unit train shipments of up to 150 railcars.

Mammoth. The Mammoth complex operates four underground room and pillar mines and a preparation plant. Coal is transported to the preparation plant using a conveyor system. The plant has a 1,200 tons per hour processing facility capacity with barge loading capabilities on the upper Kanawha River and a rail loading facility that services customers on the Norfolk Southern railway with unit trains of up to 130 railcars.

Marfork. The Marfork complex includes eight underground room and pillar mines and a preparation plant. Production from one of the mines is trucked and from five of the mines is belted directly to the Marfork preparation plant while production from the remaining two mines is belted to Edwight Resource Group's Goals preparation plant. The Marfork preparation plant has a capacity of 2,400 tons per hour. Customers are served via the CSX rail system with unit trains of up to 150 railcars.

Nicholas Energy. The Nicholas Energy complex includes one underground room and pillar mine, two surface mines, two highwall miners and a preparation plant. Coal from the underground mine is transported to the preparation plant for processing via conveyor system. Coal from the highwall miners and the portion of surface mined coal requiring processing is transported to the preparation plant using off-road trucks. Coal not requiring processing is transported via off-road trucks to a conveyor system that moves the coal directly to a rail loadout facility. The plant has a processing capacity of 1,200 tons per hour. Coal shipments are loaded into rail cars for delivery via the Norfolk Southern railway in unit trains of up to 140 railcars, or are transported via on-highway trucks to the Mammoth Resource Group's barge loading facility.

Progress. The Progress complex includes the large Twilight MTR surface mine. A dragline is also utilized at the Twilight MTR surface mine. Production from the Twilight MTR surface mine is transported via underground conveyor to the Elk Run Resource Group for processing and rail shipment.

Rawl. The Rawl complex includes three underground room and pillar mines and a preparation plant. Production from the mines is transported via truck to the preparation plant of the Stirrat Resource Group. The Rawl plant, which was idled in December 2006, has a throughput capacity of 1,450 tons per hour. Customers can be served by the Rawl plant via the Norfolk Southern railway with unit trains of up to 150 railcars.

Republic Energy. The Republic Energy complex consists of two surface mines. Direct-ship coal is trucked using on-highway trucks to various docks on the Kanawha River for barge delivery to customers and to the Marfork Resource Group for rail delivery to customers. Coal requiring processing is trucked using on-highway trucks to Mammoth Resource Group's preparation plant for processing and barge or train delivery to customers.

Stirrat. The Stirrat complex includes one surface mine, a preparation plant and the Superior loadout. The surface mine trucks coal directly to two 12,500 ton silos at the Superior loadout. The Superior loadout serves CSX railway customers with unit trains of up to 100 railcars. The Stirrat preparation plant cleans coal from three adjacent underground room and pillar mines of the Rawl Resource Group. The plant has a rated capacity of 600 tons per hour. Customers are served via the CSX rail system with unit trains of up to 100 railcars.

Kentucky Resource Groups

Coalgood Energy. The Coalgood Energy complex includes one underground room and pillar mine, one surface mine, one highwall miner and a direct-ship loadout. The coal from the surface mine is trucked off-road to the loadout, which serves CSX railway customers with unit trains of up to 100 railcars. The production from the underground mine is being stockpiled until construction is completed on an 800 tons per hour preparation plant, which is projected to be in service by April 2009. Coal from this preparation plant will be loaded onto trains from the existing loadout.

Long Fork. The Long Fork preparation plant processes coal produced by two underground room and pillar mines of the Sidney Resource Group. All production is transported via conveyor system to the Long Fork preparation plant for processing and shipping to customers. The Long Fork plant has a rated capacity of 1,500 tons per hour. The rail loading facility services customers on the Norfolk Southern railway with unit trains of up to 150 railcars.

Martin County. The Martin County complex includes two underground room and pillar mine, two surface mines and a preparation plant. Direct-ship coal production from the surface mines is shipped to river docks via truck. Surface mine coal requiring processing and production from the underground mines is transported by conveyor belt or truck to the preparation plant. Martin County's preparation plant has a throughput capacity of 1,500 tons per hour, although the throughput capacity is limited due to decreased impoundment availability. The coal from the preparation plant can be shipped either via the Norfolk Southern railway in unit trains of up to 125 railcars or to river docks via truck.

New Ridge. The New Ridge complex loads clean coal that is transported via truck from the preparation plant of the Sidney Resource Group and coal trucked directly from Sidney's surface mine. The New Ridge preparation plant has a capacity of 800 tons per hour. The preparation plant is currently idle but may be reactivated from time to time during 2009 as needed. All coal is loaded for shipment to customers via the CSX rail system in unit trains of up to 100 railcars.

Sidney. The Sidney complex includes nine underground room and pillar mines, one surface mine, a highwall miner and a preparation plant. Two of the underground mines transport coal via underground conveyor system to the Long Fork Resource Group for processing and shipment, and the remainder of the underground mines transport production via underground conveyor system or truck to Sidney's preparation plant. A portion of the coal from Sidney's preparation plant and coal from the surface mines are trucked to the New Ridge Resource Group for loading into railroad cars. Sidney's preparation plant has a capacity of 1,500 tons per hour. The rail loading facility at the preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 140 railcars.

Virginia Resource Group

Knox Creek. The Knox Creek complex includes one underground room and pillar mine, one surface mine, two highwall miners and a preparation plant. Production from the underground mine is belted by conveyor system to the preparation plant, while coal requiring processing from the surface mine is trucked to the preparation plant. The preparation plant has a feed capacity of 650 tons per hour. The preparation plant serves customers on the Norfolk Southern rail system with unit trains of up to 100 railcars.

Coal Reserves

We estimate that, as of December 31, 2008, we had total recoverable reserves of approximately 2.3 billion tons consisting of both proven and probable reserves. "Reserves" are defined by the 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. "Recoverable" reserves means coal that is economically recoverable using existing equipment and methods under federal and state laws currently in effect. Approximately 1.5 billion tons of reserves are classified as proven reserves. "Proven (measured) reserves" are defined by the SEC Industry Guide 7 as reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established. The remaining approximately 0.8 billion tons of our reserves are classified as probable reserves. "Probable reserves" are defined by the SEC Industry Guide 7 as 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.

Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and finance associates. Reserve estimates are updated annually using geologic data taken from drill holes, adjacent mine workings, outcrop prospect openings and other sources. Coal tonnages are categorized according to coal quality, seam thickness, mineability and location relative to existing mines and infrastructure. In accordance with applicable industry standards, proven reserves are those for which reliable data points are spaced no more than 2,700 feet apart. Probable reserves are those for which reliable data points are spaced 2,700 feet to 7,900 feet apart. Further scrutiny is applied using geological criteria and other factors related to profitable extraction of the coal. These criteria include seam height, roof and floor conditions, yield and marketability.

As with most coal-producing companies in Central Appalachia, the majority of our coal reserves are controlled pursuant to leases from third-party landowners. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues. These leases convey mining rights to the coal producer in exchange for a per ton or percentage of gross sales price royalty payment to the lessor. However, approximately 17% of our reserve holdings are owned and require no royalty or per ton payment to other parties. Royalty expense for coal reserves from our producing properties (owned and leased) was approximately 4.4% of Produced coal revenue for the year ended December 31, 2008.

The following table provides proven and probable reserve data by "status" (i.e., location, owned or leased, assigned or unassigned, etc.) as of December 31, 2008:

Resource Group	Location (2)	Recoverable Reserves (1) Total	Proven	Probable	Assigned (3)	Unassigned (3)	Owned	Leased
		(In Thousands of Tons)						
West Virginia								
Black Castle	Boone County	86,132	59,402	26,730	39,362	46,770	538	85,594
Delbarton	Mingo County	286,237	120,440	165,797	140,739	145,498	25	286,212
Edwight	Raleigh County	7,796	7,796	-	7,796	-	-	7,796
Elk Run	Boone County	108,782	75,615	33,167	59,488	49,294	4,660	104,122
Endurance	Boone County	23,007	23,007	-	23,007	-	22,602	405
Green Valley	Nicholas County	9,973	9,973	-	9,973	-	-	9,973
Guyandotte	Wyoming County	45,564	17,366	28,198	2,100	43,464	330	45,234
Independence	Boone County	44,466	43,156	1,310	31,487	12,979	9,482	34,984
Inman	Boone County	49,473	47,958	1,515	17,066	32,407	-	49,473
Logan County	Logan County	72,805	65,721	7,084	55,081	17,724	2,388	70,417
Mammoth	Kanawha County	86,425	66,086	20,339	73,108	13,317	42,421	44,004
Marfork	Raleigh County	133,399	105,262	28,137	74,976	58,423	815	132,584
Nicholas Energy	Nicholas County	88,795	48,186	40,609	46,379	42,416	35,517	53,278
Progress	Boone County	17,262	17,262	-	17,262	-	-	17,262
Rawl	Mingo County	108,849	81,087	27,762	74,852	33,997	1,333	107,516
Republic Energy	Raleigh County	56,208	49,688	6,520	56,208	-	-	56,208
Stirrat	Logan County	11,745	7,778	3,967	5,078	6,667	-	11,745
Kentucky								
Coalgood Energy	Harlan County	21,261	12,357	8,904	-	21,261	2,704	18,557
Long Fork	Pike County	4,964	2,764	2,200	264	4,700	-	4,964
Martin County	Martin County	48,181	31,492	16,689	2,783	45,398	1,336	46,845
New Ridge	Pike County	-	-	-	-	-	-	-
Sidney	Pike County	124,211	70,173	54,038	124,211	-	7,028	117,183
Virginia								
Knox Creek	Tazewell County	60,675	44,586	16,089	32,605	28,070	4,552	56,123
Subtotal		1,496,210	1,007,155	489,055	893,825	602,385	135,731	1,360,479
Land Management Companies: (4)								
Black King	Boone County, WV Raleigh County, WV	53,144	40,762	12,382	734	52,410	-	53,144
Boone East	Boone County, WV Kanawha County, WV	141,976	102,853	39,123	5,169	136,807	63,547	78,429
Boone West	Lincoln County, WV Logan County, WV	242,308	92,201	150,107	10,496	231,812	65,553	176,755
Ceres Land	Raleigh County, WV	33,351	24,220	9,131	-	33,351	-	33,351
Rostraver Energy (5)	Various counties, PA	94,086	44,449	49,637	-	94,086	79,907	14,179
Lauren Land	Mingo County, WV Logan County, WV Various counties, KY	167,671	107,301	60,370	11,175	156,496	18,011	149,660
New Market Land	Wyoming County, WV	5,884	2,690	3,194	-	5,884	102	5,782
Raven Resources	Raleigh County, WV Boone County, WV	18,978	18,978	-	-	18,978	-	18,978
Tennessee Consolidated Coal	Various counties, TN	26,907	1,332	25,575	-	26,907	24,054	2,853
Subtotal Land Management		784,305	434,786	349,519	27,574	756,731	251,174	533,131
Other	N/A	57,733	29,680	28,053	12,740	44,993	3,112	54,621
Total		2,338,248	1,471,621	866,627	934,139	1,404,109	390,017	1,948,231

(1) Recoverable reserves represent the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law.
(2) All of the recoverable reserves listed are in Central Appalachia, except for the Rostraver reserves, which are located in Northern Appalachia and Lauren Land reserves, a portion of which are located in the Illinois Basin. The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.
(3) Assigned Reserves represent recoverable reserves that are dedicated to a specific permitted mine; otherwise, the reserves are considered Unassigned. For Land Management Companies, Assigned Reserves have been leased to a third-party and are dedicated to a specific permitted mine of the lessee.
(4) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.
(5) Previously known as Duncan Fork.

The categorization of the "quality" (i.e., sulfur content, Btu, coal type, etc.) of coal reserves is as follows:

Resource Group	Recoverable Reserves	Recoverable Reserves (1) Sulfur Content +1% (2)	-1% (2)	Compliance (2)	Avg. Btu as Received (3)	Coal Type (4)
	(In Thousands of Tons Except Average Btu as Received)					
West Virginia						
Black Castle	86,132	34,116	52,016	22,167	12,700	Utility and Industrial
Delbarton	286,237	111,954	174,283	127,073	13,350	High Vol Met, Utility, and Industrial
Edwight	7,796	1,622	6,174	5,987	12,550	High Vol Met, Utility, and Industrial
Elk Run	108,782	47,027	61,755	51,407	13,700	High Vol Met, Utility, and Industrial
Endurance	23,007	4,952	18,055	10,047	11,850	Utility and Industrial
Green Valley	9,973	471	9,502	3,853	13,100	High Vol Met, Utility, and Industrial
Guyandotte	45,564	-	45,564	45,564	13,850	Low Vol Met
Independence	44,466	19,425	25,041	-	12,650	High Vol Met, Utility, and Industrial
Inman	49,473	32,667	16,806	16,895	12,650	High Vol Met and Utility
Logan County	72,805	22,346	50,459	39,009	12,050	High Vol Met, Utility, and Industrial
Mammoth	86,425	5,216	81,209	41,706	12,150	Utility and Industrial
Marfork	133,399	41,679	91,720	34,931	14,050	High Vol Met, Utility, and Industrial
Nicholas Energy	88,795	39,959	48,836	24,705	12,450	Utility and Industrial
Progress	17,262	6,021	11,241	11,241	12,350	High Vol Met, Utility, and Industrial
Rawl	108,849	28,061	80,788	59,614	12,350	High Vol Met, Utility, and Industrial
Republic	56,208	11,014	45,194	31,238	12,450	High Vol Met and Utility
Stirrat	11,745	223	11,522	7,663	12,300	High Vol Met, Utility, and Industrial
Kentucky						
Coalgood Energy	21,261	4,712	16,549	11,680	13,100	High Vol Met, Utility, and Industrial
Long Fork	4,964	3,500	1,464	-	12,850	Utility and Industrial
Martin County	48,181	33,900	14,281	5,120	12,500	Utility and Industrial
New Ridge	-	-	-	-	-	N/A
Sidney	124,211	47,878	76,333	52,545	13,200	High Vol Met, Utility, and Industrial
Virginia						
Knox Creek	60,675	7,022	53,653	40,250	12,350	High Vol Met, Utility, and Industrial
Subtotal	1,496,210	503,765	992,445	642,695		
Land Management Companies: (5)						
Black King	53,144	99	53,045	36,508	12,150	High Vol Met and Utility
Boone East	141,976	34,939	107,037	36,789	12,500	High Vol Met, Utility, and Low Vol Met
Boone West	242,308	130,063	112,245	79,369	13,350	High Vol Met and Utility
Ceres Land	33,351	5,991	27,360	12,740	12,700	High Vol Met and Utility
Rostraver Energy (6)	94,086	94,086	-	-	14,050	High Vol Met, Utility, and Industrial
Lauren Land	167,671	85,346	82,325	62,628	12,700	High Vol Met and Utility
New Market Land	5,884	-	5,884	5,884	12,700	High Vol Met and Low Vol Met
Raven Resources	18,978	7,449	11,529	1,369	12,100	High Vol Met and Utility
Tennessee Consolidated Coal	26,907	20,353	6,554	4,816	13,000	High Vol Met, Utility and Industrial
Subtotal Land Management	784,305	378,326	405,979	240,103		
Other	57,733	6,638	51,095	45,947	12,800	Various
Total	2,338,248	888,729	1,449,519	928,745		

(1) The reserve numbers of each Resource Group contain a moisture factor specific to the particular reserves of that Resource Group. The moisture factor represents the average moisture present in our delivered coal.
(2) +1% or -1% refers to sulfur content as a percentage in coal by weight. Compliance coal is less than 1% sulfur content by weight and is included in the -1% column.
(3) Represents an estimate of the average Btu per pound present in our coal, as it is received by the customer.
(4) Reserve holdings include metallurgical coal reserves. Although these metallurgical coal reserves receive the highest selling price in the current coal market when marketed to steel-making customers, they can also be marketed as an ultra high Btu, low sulfur utility coal for electricity generation.
(5) Land management companies are our subsidiaries whose primary purposes are to acquire and hold our reserves.
(6) Previously known as Duncan Fork.

Compliance compared to non-compliance coal

Coals are sometimes characterized as compliance or non-compliance coal. The phrase compliance coal, as it is commonly used in the coal industry, refers to compliance only with sulfur dioxide emissions standards imposed by Title IV of the Clean Air Act and indicates that when burned, the coal will produce emissions that will meet the current standard without further cleanup. A coal that is considered a compliance coal for meeting sulfur dioxide standards may not meet an emission standard for a different pollutant such as mercury. Moreover, the term compliance coal is always used with reference to the then current regulatory limit. Clean air regulations that further restrict sulfur dioxide emissions will likely reduce significantly the amount of coal that can be labeled compliance. Currently, coal classified as compliance will meet the power plant emission standard of 1.2 pounds of sulfur dioxide per million Btu's of fuel consumed. At December 31, 2008, approximately 0.9 billion tons, or 40%, of our coal reserves met the current standard as compliance coal.

Distribution

We employ transportation specialists who negotiate freight and terminal agreements with various providers, including railroads, barge lines, ocean-going vessels, bulk motor carriers and terminal facilities. Transportation specialists also coordinate with customers, mining facilities and transportation providers to establish shipping schedules that meet each customer's needs.

Our 2008 shipments of 41.0 million tons were loaded from 23 mining complexes. Rail shipments constituted 91% of total shipments, with 26% loaded on Norfolk Southern trains and 65% loaded on CSX trains. The balance was shipped from mining complexes via truck or barge.

Approximately 22% of production was ultimately delivered via the inland waterway system. Coal is loaded directly into barges, or is transported by rail or truck to docks on the Ohio, Big Sandy and Kanawha Rivers and then ultimately transported by barge to electric utilities, integrated steel producers and industrial consumers served by the inland waterway system. We also moved approximately 2% of our production to Great Lakes' ports for transport to various United States and Canadian customers.

Customers and Coal Contracts

We have coal supply commitments with a wide range of electric utilities, steel manufacturers, industrial customers and energy traders and brokers. By offering coal of both steam and metallurgical grades, we are able to serve a diverse customer base. This market diversity allows us to adjust to changing market conditions and sustain high sales volumes. The majority of our customers purchase coal for terms of one year or longer, but we also supply coal on a spot basis for some customers. At December 31, 2008, approximately 75%, 13% and 12% of Trade receivables represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 56%, 28% and 16%, respectively, as of December 31, 2007. During 2008, we had 25 separate, active agreements with our largest customer, Constellation Energy Commodities Group, Inc. ("Constellation"), with terms ranging from one month to two years which, in the aggregate accounted for 11% of our fiscal year 2008 Produced coal revenue. The largest of the 25 agreements represented less than 2% of our fiscal year 2008 Produced coal revenue. As a result, we do not consider our business to be substantially dependent upon any of these agreements, individually or in the aggregate. No other customer accounted for 10% or more of fiscal year 2008 Produced coal revenue or produced tons. For fiscal year 2009, our contracted sales under separate agreements to Constellation currently represent approximately 26% of our projected produced coal tonnage and 18% of our projected Produced coal revenue. There are no other customers to whom we expect to sell 10% or more of produced tons or to account for 10% or more of Produced coal revenue in 2009.

As is customary in the coal industry, we enter into long-term contracts (one year or more in duration) with many of our customers. These arrangements allow customers to secure a supply for their future needs and provide us with greater predictability of sales volume and sales prices. Long-term contracts are a result of extensive negotiations with customers. As a result, the terms of these contracts vary with respect to price adjustment mechanisms, pricing terms, permitted sources of supply, force majeure provisions, quality adjustments and other parameters. Some of the contracts contain price adjustment mechanisms that allow for changes to prices based on statistics from the United States Department of Labor. Coal quality specifications may be especially stringent for steel customers.

For the year ended December 31, 2008, approximately 97% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2009, coal sales volume percentage pursuant to long-term arrangements will be comparable to 2008. As of February 19, 2009, we had contractual sales commitments of approximately 101 million tons, including commitments subject to price reopener and/or optional tonnage provisions. Remaining contractual terms of our sales commitments range from one to eleven years with an average volume-weighted remaining term of approximately 3.1 years. Sixty-five percent of our total contracted sales tons are priced. As of February 19, 2009, we have committed most of our expected 2009 production. In addition, we purchase coal from third-party coal producers from time to time to supplement production and resell this coal to customers.

Suppliers

The main types of goods we purchase are mining equipment and replacement parts, explosives, fuel, tires, steel-related (including roof control) 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 supply of explosives is concentrated with one supplier, 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, supplier competition continues to develop. In recent years, demand for certain surface and underground mining equipment and off-the-road tires has increased. As a result, lead times for certain items have generally increased, although no material impact is currently expected to our cash flows, results of operations or financial condition.

Competition

The coal industry in the United States and overseas is highly competitive, with numerous producers selling into all markets that use coal. We compete against large and small producers in the United States and overseas. The NMA estimated that in 2007 there were 25 coal companies in the United States with annual production of 5 million or more tons, which together account for approximately 85% of United States production. According to the EIA, we were the sixth largest coal company in terms of tons produced in 2007, exceeded by Peabody Energy Corporation (“Peabody”), Rio Tinto Energy America, Inc., Arch Coal, Inc. (“Arch”), Foundation Coal Holdings Inc. (“Foundation”) and CONSOL Energy Inc. (“CONSOL”). However, in terms of produced coal revenue in 2007, EVA ranks us as the fourth largest United States coal company, exceeded by only Peabody, CONSOL and Arch.

We compete with other producers primarily on the basis of price, coal quality, transportation cost and reliability of supply. Continued demand for coal is also dependent on factors outside of our control, including demand for electricity and steel, general economic conditions, environmental and governmental regulations, weather, technological developments, and the availability and cost of alternative fuel sources. We sell coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition.

Historically, global coal markets have responded to increased demand and higher prices for coal by increasing production and supply. In recent years, however, capacity expansion has been somewhat limited by the increased costs of mining, high capital requirements, coal seam degradation, reserve depletion, labor shortages, transportation issues related to rail, barge and truck shipments, higher costs related to compliance with new and increasingly stringent regulations, the difficulty of obtaining permits and bonding and other factors. While these constraints persist in major coal producing countries and regions, periods of supply and demand imbalance may be extended and increased pricing volatility may result.

Other Related Operations

We have other related operations and activities in addition to our normal coal production and sales business. The following business activities are included in this category:

Coal Handling Joint Venture. We hold a 50% interest in a joint venture that owns and operates third-party end-user coal handling facilities. Certain of our subsidiaries currently operate the coal handling facilities for the joint venture.

Gas Operations. We hold interests in operations that produce, gather and market natural gas from shallow reservoirs in the Appalachian Basin. In the eastern United States, conventional natural gas reservoirs are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. The depths of the reservoirs drilled and operated by us range from 2,500 to 5,800 feet.

Nearly all of our gas production is from operations in southern West Virginia. In this region, we own and operate approximately 160 wells, 200 miles of gathering line, and various small compression facilities. Our southern West Virginia operations control approximately 27,000 acres of drilling rights. In addition, we own a majority working interest in 50 wells operated by others, and minority working interests in approximately 13 wells operated by others. The December 2008 average daily production, from the 228 wells owned or controlled, was 2.0 million cubic feet per day. We do not consider our current gas production level, revenues or costs to be material to our cash flows, results of operations or financial condition.

Other. From time to time, we also engage in the sale of certain non-strategic assets such as timber, oil and gas rights, surface properties and reserves. In addition, we have established several contractual arrangements with customers where services other than coal supply are provided on an ongoing basis. None of these contractual arrangements is considered to be material. Examples of such other services include arrangements with several metallurgical and industrial customers to coordinate shipment of coal to their stockpiles, maintain ownership of the coal inventory on their property and sell tonnage to them as it is consumed. We work closely with customers to provide other services in response to the current needs of each individual customer.

Marketing and Sales

Our marketing and sales force, based in the corporate office in Richmond, Virginia, includes sales managers, distribution/traffic managers and administrative personnel.

During the year ended December 31, 2008, we sold 41.0 million tons of produced coal for total Produced coal revenue of $2.6 billion. The breakdown of produced tons sold by market served was 66% utility, 24% metallurgical and 10% industrial. Sales were concluded with over 100 customers. Export shipment revenue totaled approximately $756.3 million, representing approximately 30% of 2008 Produced coal revenue. In 2008, we exported shipments to customers in 17 countries across the globe, which included destinations in Europe, Asia, Africa, South America and North America. Sales are made in United States dollars, which minimizes foreign currency risk.

Employees and Labor Relations

As of December 31, 2008, we had 6,743 employees, including 124 employees affiliated with the United Mine Workers of America ("UMWA"). Relations with employees are generally good, and there have been no material work stoppages in the past ten years.

Environmental, Safety and Health Laws and Regulations

The coal mining industry is subject to regulation by federal, state and local authorities on matters such as the discharge of materials into the environment, employee health and safety, permitting and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, water appropriation and legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, and storage of petroleum products and substances that are regarded as hazardous under applicable laws. The possibility exists that new legislation or regulations may be adopted that could have a significant impact on our mining operations or on our customers' ability to use coal.

Numerous governmental permits and approvals are required for mining operations. Regulations provide that a mining permit or modification can be delayed, refused or revoked if an officer, director or a stockholder with a 10% or greater interest in the entity is affiliated with or is in a position to control another entity that has outstanding permit violations. Thus, past or ongoing violations of federal and state mining laws by individuals or companies no longer affiliated with us could provide a basis to revoke existing permits and to deny the issuance of addition permits. We are required to prepare and present to federal, state or local authorities data and/or analysis pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment, public and employee health and safety. All requirements imposed by such authorities may be costly and time-consuming and may delay commencement or continuation of exploration or production operations. Accordingly, the permits we need for our mining and gas operations may not be issued, or, if issued, may not be issued in a timely fashion. Permits we need may involve requirements that may be changed or interpreted in a manner that restricts our ability to conduct our mining operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment, health and safety and, as a consequence, our activities may be more closely regulated. Such legislation and regulations, as well as future interpretations of existing laws, may require substantial increases in equipment and operating costs, delays, interruptions or a termination of operations, the extent of which cannot be predicted.

While it is not possible to quantify the expenditures we incur to maintain compliance with all applicable federal and state laws, those costs have been and are expected to continue to be significant. We post surety performance bonds or letters of credit pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, often including the cost of treating mine water discharge when necessary. Compliance with these laws has substantially increased the cost of coal mining for all domestic coal producers. We endeavor to conduct our mining operations in compliance with all applicable federal, state and local laws and regulations. However, even with our substantial efforts to comply with extensive and comprehensive regulatory requirements, violations during mining operations occur from time to time. In 2007, EPA filed suit against us and twenty-seven of our subsidiaries alleging violations of the Federal Clean Water Act. In January 2008, we announced that we had agreed with EPA to settle the lawsuit for a payment of $20 million in penalties. In 2008, we spent approximately $16.2 million to comply with environmental laws and regulations, of which $7.8 million was for reclamation, including $5.0 million for final reclamation. None of these expenditures were capitalized. We anticipate spending approximately $42.8 million and $34.8 million in such non-capital expenditures in 2009 and 2010, respectively. Of these expenditures, $31.4 million and $23.1 million for 2009 and 2010, respectively, are anticipated to be for final reclamation.

Emission Control Technology. We own a majority interest in Coalsolv, LLC (“Coalsolv”), which holds the United States marketing rights for the coal-fired plant emission control technologies developed by Cansolv Technologies, Inc. (“Cansolv”). Cansolv’s technologies remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury, carbon dioxide (CO_2), and other greenhouse gases from flue gas emissions. The Cansolv process has been utilized at various industrial facilities around the world, with additional projects underway in China and Canada. Through Coalsolv, we contributed funds for a pilot plant that has been utilized in the United States and Canada for the testing and piloting of the Cansolv SO_2, NO_X, mercury, and CO_2 capture technology on coal-fired power plants.

Mine Safety and Health

Stringent health and safety standards have been in effect since Congress enacted the Federal Coal Mine Health and Safety Act of 1969. The Federal Coal 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. A further expansion occurred in June 2006 with the enactment of the Mine Improvement and New Emergency Response Act of 2006 (“MINER Act”).

The MINER Act and related Mine Safety and Health Administration (“MSHA”) regulatory action require, among other things, improved emergency response capability, increased availability of emergency breathable air, enhanced communication and tracking systems, more available mine rescue teams, increased mine seal strength and monitoring of sealed areas in underground mines, as well as larger penalties by MSHA for noncompliance by mine operators. Coal producing states, including West Virginia and Kentucky, passed similar legislation. The bituminous coal mining industry was actively engaged throughout 2008 in activities to achieve compliance with these new requirements. These compliance efforts will continue into 2009.

In 2008, MSHA published final rules implementing Section 4 of the MINER Act that addressed mine rescue, sealing of abandoned areas, refuge alternatives, fire prevention and detection, use of air from the belt entry and civil penalty assessments. MSHA also provided guidance on wireless communication and electronic tracking systems and new requirements for the plugging of coal bed methane wells with horizontal branches in coal seams. Two additional regulations were also published related to measures to achieve alcohol and drug free mines and the use of coal mine dust personal monitors. In February 2009, the United States Court of Appeals for the District of Columbia Circuit held that the 2008 rules were not sufficient to satisfy the requirements of the Miner Act in certain respects, and remanded those portions of the rules to MSHA for reconsideration. New rules issued by the MSHA will likely contain more stringent provisions regarding training of rescue teams.

All of the states in which we operate have state programs for mine safety and health regulation and enforcement. Collectively, federal and state safety and health regulation in the coal mining industry is perhaps the most comprehensive and pervasive system for protection of employee health and safety affecting any segment of industry in the United States. While regulation has a significant effect on our operating costs, our United States competitors are subject to the same regulation.

We measure our success in this area primarily through the use of occupational injury and illness frequency rates. We believe that a superior safety and health regime is inherently tied to achieving productivity and financial goals, with overarching benefits for our shareholders, the community and the environment.

Black Lung. Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to: (i) current and former coal miners totally disabled from black lung disease; and (ii) certain survivors of a miner who dies from black lung disease. The Black Lung Disability Trust Fund, to which we must make certain tax payments based on tonnage sold, provides for the payment of medical expenses to claimants whose last mine employment was before January 1, 1970 and to claimants employed after such date, where no responsible coal mine operator has been identified for claims or where the responsible coal mine operator has defaulted on the payment of such benefits. In addition to federal acts, we are also liable under various state statutes for black lung claims. Federal benefits are offset by any state benefits paid.

Workers' Compensation. We are liable for workers' compensation benefits for traumatic injuries under state workers' compensation laws in the states in which we have operations. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation owed to an employee injured in the course of employment.

Coal Industry Retiree Health Benefit Act of 1992 and Tax Relief and Retiree Health Care Act of 2006. The Coal Industry Retiree Health Benefit Act of 1992 ("Coal Act") provides for the funding of health benefits for certain UMWA retirees. The Coal Act established the Combined Benefit Fund ("CBF") into which "signatory operators" and "related persons" are obligated to pay annual premiums for covered beneficiaries. The Coal Act also created a second benefit fund, the 1992 Benefit Plan, for miners who retired between July 21, 1992 and September 30, 1994 and whose former employers are no longer in business. On December 20, 2006, President Bush signed the Tax Relief and Retiree Health Care Act of 2006. This legislation includes important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the SSA revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies"), but phased-in their premium relief. As a pre-1988 signatory, Massey related reachback companies received the applicable premium relief. Effective October 1, 2007, reachback companies will pay only 55% of their plan year 2008 assessed premiums, 40% of their plan year 2009 assessed premiums, and 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies.

Pension Protection Act. The Pension Protection Act of 2006 ("Pension Act") has simplified and transformed the rules governing the funding of defined benefit plans, accelerated funding obligations of employers, made permanent certain provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001, made permanent the diversification rights and investment education provisions for plan participants and encouraged automatic enrollment in defined contribution 401 (k) plans. In general, most provisions of the Pension Act took effect for plan years beginning on or after December 31, 2007. Plans generally are required to set a funding target of 100% of the present value of accrued benefits and sponsors are required to amortize unfunded liabilities over a 7-year period. The Pension Act included a funding target phase-in provision consisting of a 92% funding target in 2008, 94% in 2009, 96% in 2010, and 100% thereafter. Plans with a funded ratio of less than 80%, or less than 70% using special assumptions, are deemed to be "at risk" and are subject to additional funding requirements. As of December 31, 2008, our pension plan was underfunded by $63 million. We currently expect to make contributions in 2009 of approximately $10 million. The funded status at the end of fiscal year 2009, and the need for additional future required contributions, will depend primarily on the actual return on assets during the year and the discount rate at the end of the year.

Environmental Laws

Surface Mining Control and Reclamation Act. The Surface Mining Control and Reclamation Act, ("SMCRA"), which is administered by the Office of Surface Mining Reclamation and Enforcement ("OSM"), establishes mining, environmental protection and reclamation standards for all aspects of surface mining as well as many aspects of deep mining. The SMCRA and similar state statutes require, among other things, the restoration of mined property in accordance with specified standards and an approved reclamation plan. In addition, the Abandoned Mine Land Fund, which is part of the SMCRA, imposes a fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is $0.315 per ton on surface-mined coal and $0.135 per ton on deep-mined coal. A mine operator must submit a bond or otherwise secure the performance of its reclamation obligations. Mine operators must receive permits and permit renewals for surface mining operations from the OSM or, where state regulatory agencies have adopted federally approved state programs under the act, the appropriate state regulatory authority. We accrue for reclamation and mine-closing liabilities in accordance with Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") (see Note 9 to the Notes to Consolidated Financial Statements).

Clean Water Act. Section 301 of the Clean Water Act prohibits the discharge of a pollutant from a point source into navigable waters of the United States except in accordance with a permit issued under either Section 402 or Section 404 of the Clean Water Act. Navigable waters are broadly defined to include streams, even those that are not navigable in fact, and may include wetlands. All mining operations in Appalachia generate excess material, which are typically placed in fills in adjacent valleys and hollows. Likewise, coal refuse disposal areas and coal processing slurry impoundments are located in valleys and hollows. These areas frequently contain intermittent or perennial streams, which are considered navigable waters under the Clean Water Act. An operator must secure a Clean Water Act permit before filling such streams. For approximately the past twenty-five years, operators have secured Section 404 fill permits that authorize the filling of navigable waters with material from various forms of coal mining. Operators have also obtained permits under Section 404 for the construction of slurry impoundments. Discharges from these structures require permits under Section 402 of the Clean Water Act. Section 402 discharge permits are generally not suitable for authorizing the construction of fills in navigable waters.

Clean Air Act. Coal contains impurities, including sulfur, mercury, chlorine, nitrogen oxide and other elements or compounds, many of which are released into the air when coal is burned. The Clean Air Act and corresponding state laws extensively regulate emissions into the air of particulate matter and other substances, including sulfur dioxide, nitrogen oxide and mercury. Although these regulations apply directly to impose certain requirements for the permitting and operation of our mining facilities, by far their greatest impact on us and the coal industry generally is the effect of emission limitations on utilities and other customers. Owners of coal-fired power plants and industrial boilers have been required to expend considerable resources to comply with these air pollution standards. The United States Environmental Protection Agency ("EPA") has imposed or attempted to impose tighter emission restrictions in a number of areas, some of which are currently subject to litigation. The general effect of such tighter restrictions could be to reduce demand for coal. This in turn may result in decreased production and a corresponding decrease in revenue and profits.

National Ambient Air Quality Standards. Ozone is produced by a combination of two precursor pollutants: volatile organic compounds and nitrogen oxide, a by-product of coal combustion. Particulate matter is emitted by sources burning coal as fuel, including coal fired power plants. States are required to submit to EPA revisions to their State Implementation Plans ("SIPs") that demonstrate the manner in which the states will attain National Ambient Air Quality Standards ("NAAQS") every time a NAAQS is revised by EPA. In 2006, EPA adopted a new NAAQS for fine particulate matter, which a number of states and environmental advocacy groups challenged as not sufficiently stringent to satisfy Clean Air Act requirements; in February 2009, the United States Court of Appeals for the District of Columbia Circuit agreed that EPA had inadequately explained its decision regarding several aspects of the NAAQS and remanded those to EPA for reconsideration, a process that could lead to more stringent NAAQS for fine particulate matter. EPA also adopted a more stringent ozone NAAQS on March 27, 2008. Revised SIPs for both ozone and fine particulates could require electric power generators to further reduce particulate, nitrogen oxide and sulfur dioxide emissions. In addition to the SIP process, the Clean Air Act permits states to assert claims against sources in other "upwind" states alleging that emission sources including coal fired power plants in the upwind states are preventing the "downwind" states from attaining a NAAQS. The new NAAQS for ozone and fine particulates, as well as claims by affected states, could result in additional controls being required of coal fired power plants and we are unable to predict the effect on markets for our coal.

Acid Rain Control Provisions. The acid rain control provisions promulgated as part of the Clean Air Act Amendments of 1990 in Title IV of the Clean Air Act ("Acid Rain program") required reductions of sulfur dioxide emissions from power plants. The Acid Rain program is now a mature program and we believe that any market impacts of the required controls have likely been factored into the price of coal in the national coal market.

Regional Haze Program. EPA promulgated a regional haze program designed to protect and to improve visibility at and around so-called Class I Areas, which are generally National Parks, National Wilderness Areas and International Parks. This program may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around the Class I Areas. Moreover, the program requires certain existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions, such as sulfur dioxide, nitrogen oxide and particulate matter. States were required to submit Regional Haze SIPs to EPA by December 17, 2007. Many states did not meet the December 17, 2007, deadline and we are unable to predict the impact on the coal market of the failure to submit Regional Haze SIPs by the deadline or of any subsequent submissions deadlines.

New Source Review Program. Under the Clean Air Act, new and modified sources of air pollution must meet certain new source standards ("New Source Review Program"). In the late 1990s, EPA filed lawsuits against many coal-fired plants in the eastern United States alleging that the owners performed non-routine maintenance, causing increased emissions that should have triggered the application of these new source standards. Some of these lawsuits have been settled, with the owners agreeing to install additional pollution control devices in their coal-fired plants. The remaining litigation and the uncertainty around the New Source Review Program rules could adversely impact utilities' demand for coal in general or coal with certain specifications, including the coal we produce.

Multi-Pollutant Strategies. In March 2005, EPA issued two closely related rules designed to significantly reduce levels of sulfur dioxide, nitrogen oxide and mercury: the Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR"). CAIR sets a "cap-and-trade" program in 28 states and the District of Columbia to establish emissions limits for sulfur dioxide and nitrogen oxide, by allowing utilities to buy and sell credits to assist in achieving compliance with the NAAQS for 8-hour ozone and fine particulates. CAMR as promulgated will cut mercury emissions nearly 70% by 2018 through a "cap-and-trade" program. Both rules were challenged in numerous lawsuits and the United States Court of Appeals for the District of Columbia Circuit vacated CAMR and remanded it to EPA for reconsideration on February 8, 2008. In February 2009, EPA announced its intention to develop a technology-based standard under Section 112 of the Clean Air Act to address mercury emissions rather than pursue the "cap-and-trade" approach of CAMR. The same court vacated the CAIR on July 11, 2008, but subsequently revised its remedy to a remand to EPA for reconsideration on December 23, 2008. EPA is preparing its response to the remand, but the court did not impose a response date. Regardless of the outcome of litigation on either rule, stricter controls on emissions of SO_2, NO_X and mercury are likely in some form. Any such controls may have an impact on the demand for our coal.

Global Climate Change

The United States has not implemented the 1992 Framework Convention on Global Climate Change ("Kyoto Protocol"), which became effective for many countries on February 16, 2005. The Kyoto Protocol was intended to limit or reduce emissions of greenhouse gases, such as carbon dioxide. The United States has not ratified the emission targets of the Kyoto Protocol or any other greenhouse gas agreement among parties.

Nevertheless, global climate change continues to attract considerable public and scientific attention and a considerable amount of legislative attention in the United States is being paid to global climate change and the reduction of greenhouse gas emissions, particularly from coal combustion by power plants. Enactment of laws and passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

Permitting and Compliance

Our operations are principally regulated under surface mining permits issued pursuant to the SMCRA and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. We currently have over 500 surface mining permits. In conjunction with the surface mining permits, most operations hold national pollutant discharge elimination system permits pursuant to the Clean Water Act and state counterpart water pollution control laws for the discharge of pollutants to waters. These permits are issued for terms of five years. Additionally, the Clean Water Act requires permits for operations that fill waters of the United States. Valley fills and refuse impoundments are authorized under permits issued under the Clean Water Act by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart clean air laws allowing and controlling the discharge of air pollutants. These permits are primarily permits allowing initial construction (not operation) and they do not have expiration dates.

We believe we have obtained all permits required for current operations under the SMCRA, Clean Water Act and Clean Air Act and corresponding state laws. We believe that we are in compliance in all material respects with such permits, and routinely correct violations in a timely fashion in the normal course of operations. The expiration dates of the permits are largely immaterial as the law provides for a right of successive renewal. The cost of obtaining surface mining, clean water and air permits can vary widely depending on the scientific and technical demonstrations that must be made to obtain the permits. However, our cost of obtaining a permit is rarely more than $500,000 and our cost of obtaining a renewal is rarely more than $5,000. It is impossible to predict the full impact of future judicial, legislative or regulatory developments on our operations, because the standards to be met, as well as the technology and length of time available to meet those standards, continue to develop and change.

We believe, based upon present information available to us, that accruals with respect to future environmental costs are adequate. For further discussion of our costs, see Note 9 to the Notes to Consolidated Financial Statements. However, the imposition of more stringent requirements under environmental laws or regulations, new developments or changes regarding site cleanup costs or the allocation of such costs among potentially responsible parties, or a determination that we are potentially responsible for the release of hazardous substances at sites other than those currently identified, could result in additional expenditures or the provision of additional accruals in expectation of such expenditures.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), and similar state laws affect coal mining operations by, among other things, imposing cleanup requirements for threatened or actual releases of hazardous substances that may endanger public health or welfare or the environment. Under CERCLA and similar state laws, joint and several liability may be imposed on waste generators, site owners and lessees and others regardless of fault or the legality of the original disposal activity. Although EPA excludes most wastes generated by coal mining and processing operations from the hazardous waste laws, such wastes can, in certain circumstances, constitute hazardous substances for the purposes of CERCLA. In addition, the disposal, release or spilling of some products used by coal companies in operations, such as chemicals, could implicate the liability provisions of the statute. Under 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. Our current and former coal mining operations incur, and will continue to incur, expenditures associated with the investigation and remediation of facilities and environmental conditions under CERCLA.

Endangered Species Act

The federal Endangered Species Act and counterpart state legislation protect species threatened with possible extinction. Protection of endangered species may have the effect of prohibiting or delaying us from obtaining mining permits and may include restrictions on timber harvesting, road building and other mining or agricultural activities in areas containing the affected species. Based on the species that have been identified on our properties to date and the current application of applicable laws and regulations, we do not believe there are any species protected under the Endangered Species Act that would materially and adversely affect our ability to mine coal from our properties in accordance with current mining plans.

Available Information

We make available, free of charge through our Internet website, www.masseyenergyco.com, our annual report, quarterly reports, current reports, proxy statements, Section 16 reports and other information (and any amendments thereto) as soon as practicable after filing or furnishing the material to the SEC, in addition to, our Corporate Governance Guidelines, codes of ethics and the charters of the Audit, Compensation, Executive, Finance, Governance and Nominating, and Safety, Environmental, and Public Policy Committees. These materials also may be requested at no cost by telephone at (866) 814-6512 or by mail at: Massey Energy Company, Post Office Box 26765, Richmond, Virginia 23261, Attention: Investor Relations.

Executive Officers of the Registrant

Incorporated by reference into this Part I is the information set forth in Part III, Item 10 under the caption "Executive Officers of the Registrant" (included herein pursuant to Item 401(b) of Regulation S-K).

****

GLOSSARY OF SELECTED TERMS

Ash. Impurities consisting of iron, aluminum and other incombustible matter that are contained in coal. Since ash increases the weight of coal, it adds to the cost of handling and can affect the burning characteristics of coal.

Bituminous coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 Btu per pound.

British thermal unit, or "Btu." A measure of the thermal energy required to raise the temperature of one pound of pure liquid water one degree Fahrenheit at the temperature at which water has its greatest density (39 degrees Fahrenheit).

Central Appalachia. Coal producing states and regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

Coke. A hard, dry carbon substance produced by heating coal to a very high temperature in the absence of air. Coke is used in the manufacture of iron and steel. Its production results in a number of useful byproducts.

Compliance coal. Described in Item 1. Business, under the heading "Coal Reserves."

Continuous miner. A mining machine with a continuously rolling cutting cylinder used in underground and highwall mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Direct-ship coal. Coal that is shipped without first being processed in a preparation plant.

Deep mine. An underground coal mine.

Dragline. A large machine used in the surface mining process to remove the overburden, or layers of earth and rock covering a coal seam. The dragline has a large bucket suspended from the end of a long boom. The bucket, which is suspended by cables, is able to scoop up substantial amounts of overburden as it is dragged across the excavation area.

Fossil fuel. Fuel such as coal, petroleum or natural gas formed from the fossil remains of organic material.

Highwall mining. Described in Item 1. Business, under the heading “Mining Methods.”

High vol met coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Illinois Basin. The Illinois Basin consists of the coal producing areas in Illinois, Indiana and western Kentucky.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms of one year or longer.

Longwall mining. Described in Item 1. Business, under the heading “Mining Methods.”

Low vol met coal. Coal that averages approximately 20% volatile matter. Volatile matter refers to the impurities that become gaseous when heated to certain temperatures.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as “met” coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality; composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Met coal has a particularly high Btu heat content, but low ash content.

Mine. A mine consists of those operating assets necessary to produce coal from surface or underground locations.

Nitrogen oxide (NOx). Nitrogen oxide is produced as a gaseous by-product of coal combustion.

Northern Appalachia. Northern Appalachia consists of the bituminous coal producing areas in the states of Pennsylvania, Ohio and Maryland and in the northern part of West Virginia.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Overburden ratio. The amount of overburden that must be removed to excavate a given quantity of coal. It is commonly expressed in cubic yards per ton of coal or as a ratio comparing the thickness of the overburden with the thickness of the coal bed.

Pillar. An area of coal left to support the overlying strata in an underground mine, sometimes left permanently to support surface structures.

Powder River Basin. The Powder River Basin consists of the coal producing areas in southeast Montana and northeast Wyoming.

Preparation plant. A preparation plant is a facility for crushing, sizing and washing coal to remove rock and other impurities to prepare it for use by a particular customer. Preparation plants are usually located on a mine site, although one plant may serve several mines. The washing process has the added benefit of removing some of the coal’s sulfur content.

Probable reserves. Described in Item 1. Business, under the heading “Coal Reserves.”

Proven reserves. Described in Item 1. Business, under the heading “Coal Reserves.”

Reclamation. The process of restoring land and the environment to their approximate original state following mining activities. The process commonly includes “recontouring” or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

Reserve. Described in Item 1. Business, under the heading “Coal Reserves.”

Resource Group. An organizational unit, generally located within a specific geographic locale, that contains one or more of the following operations related to the mining, processing or shipping of coal: underground mine, surface mine, preparation plant or load-out facility.

Roof. The stratum of rock or other mineral above a coal seam; the overhead surface of a coal working place.

Room and pillar mining. Described in Item 1. Business, under the heading “Mining Methods.”

Scrubber (flue gas desulfurization unit). Any of several forms of chemical/physical devices that operate to neutralize sulfur and other greenhouse gases formed during coal combustion. These devices combine the sulfur in gaseous emissions with other chemicals to form inert compounds, such as gypsum, that must then be removed for disposal. Although effective in substantially reducing sulfur from combustion gases, scrubbers require about 6% to 7% of a power plant’s electrical output and thousands of gallons of water to operate.

Steam coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as utility coal.

Stoker coal. Coal that is sized to a specific, standard range. Stoker coal is typically one quarter inch by one and one quarter to one and three quarter inch.

Sulfur. One of the elements present in varying quantities in coal that reacts with air when coal is burned to form sulfur dioxide.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. “Low sulfur” coal has a variety of definitions, but typically is used to describe coal consisting of 1.0% or less sulfur.

Sulfur dioxide (SO_2). Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Surface mining. Described in Item 1. Business, under the heading “Mining Methods.”

Tons. A “short” or net ton is equal to 2,000 pounds. A “long” or British ton is approximately 2,240 pounds; a “metric” ton is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Annual Report on Form 10-K.

Underground mine. Also known as a “deep” mine. Usually located several hundred feet below the earth’s surface, an underground mine’s coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Unit train. A railroad train of a specified number of railroad cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in Btu heat content and higher in volatile matter than metallurgical coal. Also known as steam coal.

****

Item 1A. Risk Factors

We are subject to a variety of risks, including, but not limited to, those risk factors set forth below and those referenced herein to other Items contained in this Annual Report on Form 10-K, including Item 1. Business, under the headings "Customers and Coal Contracts," "Competition," "Environmental, Safety and Health Laws and Regulations," Item 3. Legal Proceedings and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), under the headings "Critical Accounting Estimates and Assumptions," "Certain Trends and Uncertainties" and elsewhere in MD&A.

We could be negatively impacted by the competitiveness of the markets in which we compete and declines in the market demand for coal.

We compete with coal producers in various regions of the United States and overseas for domestic and international sales. Continued domestic demand for our coal and the prices that we will be able to obtain primarily will depend upon coal consumption patterns of the domestic electric utility industry and the domestic steel industry. Consumption by the domestic utility industry is affected by the demand for electricity, environmental and other governmental regulations, technological developments and the price of competing coal and alternative fuel supplies including nuclear, natural gas, oil and renewable energy sources, including hydroelectric power. Consumption by the domestic steel industry is primarily affected by economic growth and the demand for steel used in construction as well as appliances and automobiles. In recent years and until a worldwide financial crisis developed in mid-2008, the competitive environment for coal was impacted by sustained growth in a number of the largest markets in the world, including the United States, China, Japan and India, where demand for both electricity and steel supported pricing for steam and metallurgical coal. The financial crisis has reduced demand and increased competition in supplying these markets. The cost of ocean transportation and the value of the United States dollar in relation to foreign currencies significantly impact the relative attractiveness of our coal as we compete on price with other foreign coal producing sources. Increased competition by competing coal producers or producers of alternate fuels in the markets in which we serve could cause a decrease in demand and/or pricing for our coal, adversely impacting our cash flows, results of operations or financial condition.

Portions of our coal reserves possess quality characteristics that enable us to mine, process and market them as either metallurgical coal or high quality steam coal, depending on the prevailing conditions in the markets for metallurgical and steam coal. A decline in the metallurgical market relative to the steam market could cause us to shift coal from the metallurgical market to the steam market, potentially reducing the price we could obtain for this coal and adversely impacting our cash flows, results of operations or financial condition.

Demand for our coal depends on its price and quality and the cost of transporting it to our customers.

Coal prices are influenced by a number of factors and may vary dramatically by region. The two principal components of the price of coal are the price of coal at the mine, which is influenced by mine operating costs and coal quality, and the cost of transporting coal from the mine to the point of use. The cost of mining the coal is influenced by geologic characteristics such as seam thickness, overburden ratios and depth of underground reserves. Underground mining is generally more expensive than surface mining as a result of higher costs for labor (including reserves for future costs associated with labor benefits and health care) and capital costs (including costs for mining equipment and construction of extensive ventilation systems). As of January 31, 2009, we operated 46 active underground mines, including two which employ both room and pillar and longwall mining, and 20 active surface mines, with 11 highwall miners.

Transportation costs represent a significant portion of the delivered cost of coal and, as a result, the cost of delivery is a critical factor in a customer's purchasing decision. Increases in transportation costs could make coal a less competitive source of energy. Such increases could have a material impact on our ability to compete with other energy sources and on our cash flows, results of operations or financial condition. Conversely, significant decreases in transportation costs could result in increased competition from coal producers in other parts of the country or the world, including coal imported into the United States (several United States ports have recently increased or announced plans to increase their capacity to handle imported coal). For instance, coal mines in the western United States could become an increasingly attractive source of coal to consumers in the eastern part of the United States if the costs of transporting coal from the west were significantly reduced and/or rail capacity was increased.

A significant decline in coal prices in general could adversely affect our operating results and cash flows.

Our results are highly dependent upon the prices we receive for our coal. Decreased demand for coal, both domestically and internationally, is causing spot prices and the prices we are able to negotiate on long-term contracts to decline. The lower prices could negatively affect our cash flows, results of operations or financial condition, if we are unable to increase productivity and/or decrease costs in order to maintain our margins.

We depend on continued demand from our customers.

Reduced demand from or the loss of our largest customers could have an adverse impact on our ability to achieve projected revenue. Decreases in demand may result from, among other things, a reduction in consumption by the electric generation industry and/or the steel industry, the availability of other sources of fuel at cheaper costs and a general slow-down in the economy. When our contracts with customers expire, there can be no assurance that the customers either will extend or enter into new long-term contracts or, in the absence of long-term contracts, that they will continue to purchase the same amount of coal as they have in the past or on terms, including pricing terms, as favorable as under existing arrangements. For example, our largest customer, Constellation, accounted for 11% of fiscal year 2008 Produced coal revenue. For fiscal year 2009, our contracted sales to Constellation currently represent approximately 26% of our projected produced coal tonnage and 18% of our projected Produced coal revenue. There are no other customers to whom we expect to sell 10% or more of produced tons or to account for 10% or more of Produced coal revenue in 2009. In the event that a large customer account is lost or a long-term contract is not renewed, profits could suffer if alternative buyers are not willing to purchase our coal on comparable terms.

There may be adverse changes in price, volume or terms of our existing coal supply agreements.

Many of our coal supply agreements contain provisions that permit the parties to adjust the contract price upward or downward at specified times. These contracts may be adjusted 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. Coal supply agreements also typically contain force majeure provisions allowing temporary suspension of performance by us or the customer for 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.

Our financial condition may be adversely affected if we are required by some of our customers to provide performance assurances for certain below-market sales contracts.

Contracts covering a significant portion of our contracted sales tons contain provisions that could require us to provide performance assurances if we experience a material adverse change or, under certain other contracts, if the customer believes our creditworthiness has become unsatisfactory. Generally, under such contracts, performance assurances are only required if the contract price per ton of coal is below the current market price of the coal. Certain of the contracts limit the amount of performance assurance to a per ton amount in excess of the contract price, while others have no limit. The performance assurances are generally provided by the posting of a letter of credit, cash collateral, other security, or a guaranty from a creditworthy guarantor. As of December 31, 2008, we have not received any requests from any of our customers to provide performance assurances. If we are required to post performance assurances on some or all of our contracts with performance assurances provisions, there could be a material adverse impact on our cash flows, results of operations or financial condition.

The level of our indebtedness could adversely affect our ability to grow and compete and prevent us from fulfilling our obligations under our contracts and agreements.

At December 31, 2008, we had $1,465.6 million of total indebtedness outstanding, which represented 58.6% of our total book capitalization. During 2008, we issued $690 million of 3.25% convertible senior notes due 2015 (“3.25% Notes”) and tendered for and retired $313.1 million of our 6.625% senior notes due 2010 (“6.625% Notes”). We have significant debt, lease and royalty obligations. Our ability to satisfy debt service, lease and royalty obligations and to effect any refinancing of indebtedness will depend upon future operating performance, which will be affected by prevailing economic conditions in the markets that we serve as well as financial, business and other factors, many of which are beyond our control. We may be unable to generate sufficient cash flow from operations and future borrowings, or other financings may be unavailable in an amount sufficient to enable us to fund our debt service, lease and royalty payment obligations or our other liquidity needs.

Our relative amount of debt could have material consequences to our business, including, but not limited to: (i) making it more difficult to satisfy debt covenants and debt service, lease payments and other obligations; (ii) making it more difficult to pay quarterly dividends as we have in the past; (iii) increasing our vulnerability to general adverse economic and industry conditions; (iv) limiting our ability to obtain additional financing to fund future acquisitions, working capital, capital expenditures or other general corporate requirements; (v) reducing the availability of cash flows from operations to fund acquisitions, working capital, capital expenditures or other general corporate purposes; (vi) limiting our flexibility in planning for, or reacting to, changes in the business and the industry in which we compete; or (vii) placing us at a competitive disadvantage with competitors with relatively lower amounts of debt. Any of the above-listed factors could have an adverse effect on our business, financial condition and results of operations and our ability to meet our debt payment obligations.

The covenants in our credit facility and the indentures governing debt instruments impose restrictions that may limit our operating and financial flexibility.

Our $175 million asset-based loan credit facility ("ABL Facility") contains a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (1) incur additional indebtedness; (2) increase common stock dividends above specified levels; (3) make loans and investments; (4) prepay, redeem or repurchase debt; (5) engage in mergers, consolidations and asset dispositions; (6) engage in affiliate transactions; (7) create any lien or security interest in any real property or equipment; (8) engage in sale and leaseback transactions; and (9) make distributions from subsidiaries. A decline in our operating results or other adverse factors, including a significant increase in interest rates, could result in us being unable to comply with certain covenants contained in the ABL Facility, which become operative only when our Average Excess Availability (as defined in the ABL Facility) is less than $30 million. These financial covenants include a Minimum Consolidated Fixed Charge Ratio of 1.00 to 1.00 and a minimum Consolidated Net Worth of $550 million under the terms of the ABL Facility (currently approximately $400 million as adjusted for Accounting Changes).

The indentures governing certain of our senior notes also contain a number of significant restrictions and covenants that may limit our ability and our subsidiaries' ability to, among other things: (1) incur additional indebtedness; (2) subordinate indebtedness to other indebtedness unless such subordinated indebtedness is also subordinated to the notes; (3) pay dividends or make other distributions or repurchase or redeem our stock or subordinated indebtedness; (4) make investments; (5) sell assets and issue capital stock of restricted subsidiaries; (6) incur liens; (7) enter into agreements restricting our subsidiaries' ability to pay dividends; (8) enter into sale and leaseback transactions; (9) enter into transactions with affiliates; and (10) consolidate, merge or sell all or substantially all of our assets. 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 the lenders and, in the case of an event of default under our ABL Facility, it could permit the lenders to foreclose on our assets securing the loans under the ABL Facility. If the 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 or on terms that are acceptable to us. If our debt is in default for any reason, our cash flows, results of operations or financial condition could be materially and adversely affected. In addition, complying with these covenants may also cause us to take actions that are not favorable to our shareholders and holders of our senior notes and may make it more difficult for us to successfully execute our business strategy and compete against companies that are not subject to such restrictions.

We are subject to being adversely affected by the potential inability to renew or obtain surety bonds.

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation and to satisfy other miscellaneous obligations. These bonds are typically renewable annually. Surety bond issuers and holders may not continue to renew the bonds or may demand additional collateral upon those renewals. We are also subject to increases in the amount of surety bonds required by federal and state laws as these laws change or the interpretation of these laws changes. Our failure to maintain, or inability to acquire, surety bonds that are required by state and federal law would have a material adverse impact on us, possibly by prohibiting us from developing properties that we desire to develop. That failure could result from a variety of factors including the following: (i) lack of availability, higher expense or unfavorable market terms of new bonds; (ii) restrictions on availability of collateral for current and future third-party surety bond issuers under the terms of our senior notes or revolving credit facilities; (iii) our inability to meet certain financial tests with respect to a portion of the post-mining reclamation bonds; and (iv) the exercise by third-party surety bond issuers of their right to refuse to renew or issue new bonds.

We depend on our ability to continue acquiring and developing economically recoverable coal reserves.

A key component of our future success is our ability to continue acquiring coal reserves for development that have the geological characteristics that allow them to be economically mined. Replacement reserves may not be available or, if available, may not be capable of being mined at costs comparable to those characteristics of the depleting mines. An inability to continue acquiring economically recoverable coal reserves could have a material impact on our cash flows, results of operations or financial condition.

We face numerous uncertainties in estimating economically recoverable coal reserves, and inaccuracies in estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves, including many factors beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by us. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (1) geological conditions; (2) historical production from the area compared with production from other producing areas; (3) the effects of regulations and taxes by governmental agencies; (4) future prices; and (5) future operating costs.

Each of these factors may vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties may vary substantially. As a result, our estimates may not accurately reflect our actual reserves. Actual production, revenues and expenditures with respect to reserves will likely vary from estimates, and these variances may be material.

Defects in title or loss of any leasehold interests in our properties could limit our ability to mine our properties or result in significant unanticipated costs.

A significant portion of our mining operations occurs on properties that we lease. Title defects or the loss of leases could adversely affect our ability to mine the reserves covered by those leases. Our current practice is to obtain a title review from a licensed attorney prior to leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. Separate title confirmation sometimes is not required when leasing reserves where mining has occurred previously. Our right to mine some of our reserves may be adversely affected if defects in title or boundaries exist. In order to obtain leases to conduct our mining operations on property where these defects exist, we may have to incur unanticipated costs. In addition, we may not be able to successfully negotiate new leases for properties containing additional reserves, or maintain our leasehold interests in properties where we have not commenced mining operations during the term of the lease.

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

An increase in the demand for coal could attract new investors to the coal industry, which could spur the development of new mines, and result in added production capacity throughout the industry. During 2008 we increased our coal production having added 19 additional coal mines in the last twelve months. By the end of 2008, our expansion work was continuing and was largely complete. Further expansion plans for 2009 have been deferred or cancelled in light of the changes in market conditions. Several of our competitors have also been increasing their production capacity; however, the recent global financial crisis has caused some of these competitors to announce delays in their expansion projects. Higher price levels of coal could further encourage the development of expanded capacity by new or existing coal producers. Any resulting increases in capacity could further reduce coal prices and reduce our margins.

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

We sometimes obtain coal from brokerage sources and contract miners to fulfill deliveries under our coal supply agreements. Some of our brokerage sources and contract miners may experience adverse geologic mining, escalated operating costs and/or financial difficulties that make their delivery of coal to us at the contracted price difficult or uncertain. Our profitability or exposure to loss on transactions or relationships such as these may be affected based upon the reliability of the supply or the ability to substitute, when economical, third-party coal sources, with internal production or coal purchased in the market and other factors.

Decreased availability or increased costs of key equipment, supplies or commodities such as diesel fuel, steel, explosives, magnetite and tires could decrease our profitability.

Our operations are dependant on reliable supplies of mining equipment, replacement parts, explosives, diesel fuel, tires, magnetite and steel-related products (including roof bolts). If the cost of any mining equipment or key supplies increases significantly, or if they should become unavailable due to higher industry-wide demand or less production by suppliers, there could be an adverse impact on our cash flows, results of operations or financial condition. The supplier base providing mining materials and equipment has been relatively consistent in recent years, although there continues to be consolidation. This consolidation has resulted in a situation where purchases of explosives and certain underground mining equipment are concentrated with single suppliers. In recent years, mining industry demand growth has exceeded supply growth for certain surface and underground mining equipment and heavy equipment tires. As a result, lead times for certain items have generally increased.

Transportation disruptions could impair our ability to sell coal.

We are dependent on our transportation providers to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lockouts, fuel shortages or other events could temporarily impair our ability to supply coal to customers. Our ability to ship coal could be negatively impacted by a reduction in available and timely rail service. Lack of sufficient resources to meet a rapid increase in demand, a greater demand for transportation to export terminals and rail line congestion all could contribute to a disruption and slowdown in rail service. We continue to experience rail service delays and disruptions in service which are negatively impacting our ability to deliver coal to customers and which may adversely affect our results of operations.

Severe weather may affect our ability to mine and deliver coal.

Severe weather, including flooding and excessive ice or snowfall, when it occurs, can adversely affect our ability to produce, load and transport coal, which may negatively impact our cash flows, results of operations or financial condition.

Federal, state and local laws and government regulations applicable to operations increase costs and may make our coal less competitive than other coal producers.

We incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety and endangered species laws, regulations and enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our operations. The costs of compliance with applicable regulations and liabilities assessed for compliance failure could have a material adverse impact on our cash flows, results of operations or financial condition.

New legislation and new regulations may be adopted which could materially adversely affect our mining operations, cost structure or our customers' ability to use coal. New legislation and new regulations may also require us, as well as our customers, to change operations significantly or incur increased costs. The United States Environmental Protection Agency (the "EPA") has undertaken broad initiatives to increase compliance with emissions standards and to provide incentives to our customers to decrease their emissions, often by switching to an alternative fuel source or by installing scrubbers or other expensive emissions reduction equipment at their coal-fired plants.

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.

The Clean Air Act and similar state and local laws extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides and other compounds emitted into the air from electric power plants, which are the largest end-users of our coal. Such regulation may require significant emissions control expenditures for many coal-fired power plants. As a result, the generators may switch to other fuels that generate less of these emissions or install more effective pollution control equipment, possibly reducing future demand for coal and the construction of coal-fired power plants. The majority 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.

Global climate change continues to attract considerable public and scientific attention. Widely publicized scientific reports, such as the Fourth Assessment Report of the Intergovernmental Panel on Climate Change released in 2007, have also engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. A considerable and increasing amount of attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. According to the EIA report, "Emissions of Greenhouse Gases in the United States 2007," coal combustion accounts for 30% of man-made greenhouse gas emissions in the United States. Legislation was introduced in Congress in the past several years to reduce greenhouse gas emissions in the United States and, although no bills to reduce such emissions have yet passed either house of Congress, bills to reduce such emissions remain pending and others are likely to be introduced. President Obama campaigned in favor of a "cap-and-trade" program to require mandatory greenhouse gas emissions reductions and since his election has continued to express support for such legislation, contrary to the previous administration. The United States Supreme Court's 2007 decision in *Massachusetts v. Environmental Protection Agency* ruled that EPA improperly declined to address carbon dioxide impacts on climate change in a rulemaking related to new motor vehicles. The reasoning of the court decision could affect other federal regulatory programs, including those that directly relate to coal use. In July 2008, EPA published an Advanced Notice of Proposed Rulemaking (ANPR) seeking comments regarding the regulation of greenhouse gas emissions; and in February 2009 the newly appointed administrator of EPA granted a petition by environmental advocacy groups to reconsider an interpretive memorandum by her predecessor in December 2008 that concluded the Clean Air Act's Prevention of Significant Deterioration program does not extend to carbon dioxide emissions, a decision that could lead to carbon dioxide emissions from coal-fired power plants being a consideration in permitting decisions. In addition, a growing number of states in the United States are taking steps to require greenhouse gas emissions reductions from coal-fired power plants. Enactment of laws and promulgation of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions, could result in electric generators switching from coal to other fuel sources.

As part of the United Nations Framework Convention on Climate Change, representatives from 187 nations met in Bali, Indonesia in December 2007 to discuss a program to limit greenhouse gas emissions after 2012. The United States participated in the conference. The convention adopted what is called the "Bali Action Plan." The Bali Action Plan contains no binding commitments, but concludes that "deep cuts in global emissions will be required" and provides a timetable for two years of talks to shape the first formal addendum to the 1992 United Nations Framework Convention on Climate Change treaty since the Kyoto Protocol. The ultimate outcome of the Bali Action Plan, and any treaty or other arrangement ultimately adopted by the United States or other countries, may have a material adverse impact on the global supply and demand for coal. This is particularly true if cost effective technology for the capture and sequestration of carbon dioxide is not sufficiently developed. Technologies that may significantly reduce emissions into the atmosphere of greenhouse gases from coal combustion, such as carbon capture and sequestration (which captures carbon dioxide at major sources such as power plants and subsequently stores it in nonatmospheric reservoirs such as depleted oil and gas reservoirs, unmineable coal seams, deep saline formations, or the deep ocean) have attracted and continue to attract the attention of policy makers, industry participants, and the public. For example, in July 2008 EPA proposed rules that would establish, for the first time, requirements specifically for wells used to inject carbon dioxide into geologic formations. Considerable uncertainty remains, not only regarding rules that may become applicable to carbon dioxide injection wells but also concerning liability for potential impacts of injection, such as groundwater contamination or seismic activity. In addition, technical, environmental, economic, or other factors may delay, limit, or preclude large-scale commercial deployment of such technologies, which could ultimately provide little or no significant reduction of greenhouse gas emissions from coal combustion.

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

Our operations may adversely impact the environment which could result in material liabilities to us.

The processes required to mine coal may cause certain impacts or generate certain materials that might adversely affect the environment from time to time. The mining processes we use could cause us to become subject to claims for toxic torts, natural resource damages and other damages as well as for the investigation and clean up of soil, surface water, groundwater, and other media. Such claims may arise, for example, out of conditions at sites that we currently own or operate, as well as at sites that we previously owned or operated, or may acquire. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share.

Certain coal that we mine needs to be cleaned at preparation plants, which generally require coal refuse areas and/or slurry impoundments. Such areas and impoundments are subject to extensive regulation and monitoring. Slurry impoundments have been known to fail, releasing large volumes of coal slurry into nearby surface waters and property, resulting in damage to the environment and natural resources, as well as injuries to wildlife. We maintain coal refuse areas and slurry impoundments at a number of our mining complexes. If one of our impoundments were to fail, we could be subject to substantial claims for the resulting environmental impact and associated liability, as well as for fines and penalties.

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

These and other similar unforeseen impacts that our operations may have on the environment, as well as exposures to certain substances or wastes associated with our operations, could result in costs and liabilities that could materially and adversely affect us and could have a material adverse impact on our cash flows, results of operations or financial condition.

The Mine Safety and Health Administration ("MSHA") or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed, which could adversely affect our ability to meet our customers' demands.

MSHA or other federal or state regulatory agencies may order certain of our mines to be temporarily or permanently closed. Our customers may challenge our issuance of force majeure notices in connection with such closures. If these challenges are successful, we may have to purchase coal from third-party sources to satisfy those challenges; negotiate settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, terminate customers' contracts or face claims initiated by our customers against us. The resolution of these challenges could have a material adverse impact on our cash flows, results of operations or financial condition.

We must obtain governmental permits and approvals for mining operations, which can be a costly and time-consuming process, can result in restrictions on our operations, and is subject to litigation that may delay or prevent us from obtaining necessary permits.

Our operations are principally regulated under surface mining permits issued pursuant to the Surface Mining Control and Reclamation Act (the "SMCRA") and state counterpart laws. Such permits are issued for terms of five years with the right of successive renewal. Additionally, the Clean Water Act requires permits for operations that discharge into waters of the United States. Valley fills and refuse impoundments are authorized under permits issued by the United States Army Corps of Engineers. Such permitting under the Clean Water Act has been a frequent subject of litigation by environmental advocacy groups that has resulted in periodic declines in such permits issued by the United States Army Corps of Engineers. Additionally, certain surface mines and preparation plants have permits issued pursuant to the Clean Air Act and state counterpart laws allowing and controlling the discharge of air pollutants. Regulatory authorities exercise considerable discretion in the timing of permit issuance. Requirements imposed by these authorities may be costly and time-consuming and may result in delays in, or in some instances preclude, the commencement or continuation of development or production operations. Adverse outcomes in lawsuits challenging permits or failure to comply with applicable regulations could result in the suspension, denial or revocation of required permits, which could have a material adverse impact on our cash flows, results of operations or financial condition.

The loss of key personnel or the failure to attract qualified personnel could affect our ability to operate the Company effectively.

The successful management of our business is dependent on a number of key personnel. Our future success will be affected by our continued ability to attract and retain highly skilled and qualified personnel. There are no assurances 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 an adverse affect on our cash flows, results of operations or financial condition.

Shortages of skilled labor in the Central Appalachian coal industry may pose a risk in achieving high levels of productivity at competitive costs.

Coal mining continues to be a labor-intensive industry. In recent years, we have encountered a shortage of experienced mine workers when the demand and prices for all specifications of coal we mine increased appreciably. The hiring of these less experienced workers has negatively impacted our productivity and cash costs. A continued lack of skilled miners could continue to have an adverse impact on our labor productivity and cost and our ability to meet current production requirements to fulfill existing sales commitments or to expand production to meet the increased demand for coal.

Union represented labor creates an increased risk of work stoppages and higher labor costs.

At December 31, 2008, approximately 1.8% of our total workforce was represented by the United Mine Workers of America (the "UMWA"). Our unionized workforce is spread out amongst five of our coal preparation plants and one smaller surface mine. In 2008, these preparation plants handled approximately 29.3% of our coal production. We are currently in the process of negotiating successor collective bargaining agreements for ones that have expired. In connection with these negotiations and with respect to our unionized operations generally, there may be an increased risk of strikes and other labor disputes, as well as higher labor costs. If some or all of our current open shop operations were to become unionized, we could be subject to additional risk of work stoppages, other labor disputes and higher labor costs, which could adversely affect the stability of production and reduce net income.

Legislation has been proposed to the United States Congress to enact a law allowing for workers to choose union representation solely by signing election cards ("Card Check"), which would eliminate the use of secret ballots to elect union representation. While the impact is uncertain, if Card Check legislation is enacted into law, it will be administratively easier for the UMWA to unionize coal mines and may lead to more coal mines becoming unionized.

Inflationary pressures on supplies and labor may adversely affect our profit margins.

Although inflation in the United States has been relatively low in recent years, over the course of the last two to three years, we have been significantly impacted by price inflation in many of the components of our cost of produced coal revenue, such as fuel, steel and labor. If the prices for which we sell our coal do not increase in step with rising costs or if these costs do not decline sufficiently, our profit margins would be reduced and our cash flows, results of operations or financial condition would be adversely affected.

We are subject to various legal proceedings, which may have a material effect on our business.

We are parties to a number of legal proceedings incident to normal business activities. Some of the allegations brought against us are with merit, while others are not. There is always the potential that an individual matter or the aggregation of many matters could have a material adverse effect on our cash flows, results of operations or financial position. See Note 18 of the Notes to Consolidated Financial Statements.

We have significant reclamation and mine closure obligations. If the assumptions underlying our accruals are materially inaccurate, we could be required to expend greater amounts than anticipated.

SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Estimates of our total reclamation and mine-closing liabilities are based upon permit requirements and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by management and engineers. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

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

We are subject to long-term liabilities under a variety of benefit plans and other arrangements with current and former employees. These obligations have been estimated based on actuarial assumptions, including actuarial estimates, assumed discount rates, estimates of life expectancy, expected returns on pension plan assets and changes in healthcare costs.

If our assumptions relating to these benefits change in the future or are incorrect, we may be required to record additional expenses, which would reduce our profitability. In addition, future regulatory and accounting changes relating to these benefits could result in increased obligations or additional costs, which could also have a material adverse impact on our cash flows, results of operations or financial condition. See also Notes 5, 10 and 11 of the Notes to Consolidated Financial Statements for further discussion.

Our pension plans are currently underfunded and we may have to make significant cash payments to the plans, reducing the cash available for our business

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. We currently expect to make contributions in 2009 of approximately $10 million. If the performance of the assets in our pension plans does not meet our expectations, or if other actuarial assumptions are modified, our contributions could be higher than we expect.

The value of the assets held in our pension plans has been adversely affected by the recent disruptions in the financial markets, and the applicable discount rates applied in determining our pension liabilities have also been negatively affected by the crisis in the financial markets. As a result, as of December 31, 2008, our annual measurement date, our pension plan was underfunded by $63 million (based on the actuarial assumptions used for SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158")). Our pension plans are subject to the Employee Retirement Income Security Act of 1974 ("ERISA"). Under ERISA, the Pension Benefit Guaranty Corporation, or PBGC, has the authority to terminate an underfunded pension plan under limited circumstances. In the event our pension plan is terminated for any reason while the plan is underfunded, we will incur a liability to the PBGC that may be equal to the entire amount of the underfunding.

Provisions in our restated certificate of incorporation and restated bylaws, the agreements governing our indebtedness and Delaware law may discourage a takeover attempt even if doing so might be beneficial to our shareholders.

Provisions contained in our restated certificate of incorporation and restated bylaws could impose impediments to the ability of a third-party to acquire us even if a change of control would be beneficial to you. Provisions of our restated certificate of incorporation and restated bylaws impose various procedural and other requirements, which could make it more difficult for stockholders to effect certain corporate actions. For example, our restated certificate of incorporation authorizes our board of directors to determine the rights, preferences, privileges and restrictions of unissued series of preferred stock, without any vote or action by our stockholders. Thus, our board of directors can authorize and issue shares of preferred stock with voting or conversion rights that could adversely affect the voting or other rights of holders of Common Stock. We are also subject to provisions of Delaware law that prohibit us from engaging in any business combination with any "interested stockholder," meaning, generally, that a stockholder who beneficially owns more than 15% of Common Stock cannot acquire us for a period of three years from the date this person became an interested stockholder unless various conditions are met, such as approval of the transaction by our board of directors. These provisions may have the effect of delaying or deterring a change of control of our Company, and could limit the price that certain investors might be willing to pay in the future for shares of Common Stock.

If a "fundamental change" (as defined in the indenture governing the 3.25% convertible senior notes due 2015 ("3.25% Notes")) occurs, holders of the 3.25% Notes will have the right, at their option, either to convert their 3.25% Notes or require us to repurchase all or a portion of their 3.25% Notes, and holders of the 4.75% convertible senior notes due 2023 and 2.25% convertible senior notes due 2024 will have the right to require us to repurchase all or a portion of their notes. In the event of a "make-whole fundamental change" (as defined in the indenture governing the 3.25% Notes), we also may be required to increase the conversion rate applicable to any 3.25% Notes surrendered for conversion. In addition, the indentures for the convertible notes prohibit us from engaging in certain mergers or acquisitions unless, among other things, the surviving entity is a U.S. entity that assumes our obligations under the convertible notes. Certain of our debt instruments impose similar restrictions on us, including with respect to mergers or consolidations with other companies and the sale of substantially all of our assets. These provisions could prevent or deter a third-party from acquiring us even where the acquisition could be beneficial to you.

We may not realize all or any of the anticipated benefits from acquisitions we undertake, as acquisitions entail a number of inherent risks.

From time to time we expand our business and reserve position through acquisitions of businesses and assets, mergers, joint ventures or other transactions. Such transactions involve various inherent risks, such as:

- uncertainties in assessing the value, strengths and potential profitability of, and identifying the extent of all weaknesses, risks, contingent and other liabilities (including environmental liabilities) of, acquisition or other transaction candidates;
- the potential loss of key customers, management and employees of an acquired business;
- the ability to achieve identified operating and financial synergies anticipated to result from an acquisition or other transaction;
- problems that could arise from the integration of the acquired business;
- the risk of obtaining mining permits for acquired coal assets; and
- unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying the acquisition or other transaction rationale.

Any one or more of these and other factors could cause us not to realize the benefits anticipated to result from the acquisition of businesses or assets or could result in unexpected liabilities associated with these acquisitions.

Foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We rely on customers in other countries for a portion of our sales, with shipments to countries in North America, South America, Europe, Asia and Africa. We compete in these international markets against coal produced in other countries. Coal is sold internationally in United States dollars. As a result, mining costs in competing producing countries may be reduced in United States dollar terms based on currency exchange rates, providing an advantage to foreign coal producers. Currency fluctuations among countries purchasing and selling coal could adversely affect the competitiveness of our coal in international markets.

Terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war may negatively affect our cash flows, results of operations or financial condition.

Our business is affected by general economic conditions, fluctuations in consumer confidence and spending, and market liquidity, which can decline as a result of numerous factors outside of our control, such as terrorist attacks and acts of war. Future terrorist attacks against United States targets, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting customers may materially adversely affect operations. As a result, there could be delays or losses in transportation and deliveries of coal to customers, decreased sales of coal and extension of time for payment of accounts receivable from customers. Strategic targets such as energy-related assets may be at greater risk of future terrorist attacks than other targets in the United States. In addition, such disruption may lead to significant increases in energy prices that could result in government-imposed price controls. It is possible that any, or a combination, of these occurrences could have a material impact on cash flows, results of operations or financial condition.

Coal mining is subject to inherent risks, some for which we maintain third-party insurance and some for which we self-insure.

Our operations are subject to certain events and conditions that could disrupt operations, including fires and explosions, accidental mine water discharges, coal slurry releases and impoundment failures, natural disasters, equipment failures, maintenance problems and flooding. We maintain insurance policies that provide limited coverage for some, but not all, of these risks. Even where insurance coverage applies, there can be no assurance that these risks would be fully covered by insurance policies and insurers may contest their obligations to make payments. Failures by insurers to make payments could have a material adverse effect on our cash flows, results of operations or financial condition. We self-insure our highwall miners and underground equipment, including our longwalls. We do not currently carry business interruption insurance.

An accounting change for cash settled convertible debt instruments applicable to our 3.25% Notes will likely cause our reported interest expense to increase.

In May 2008, the FASB issued FASB Staff Position APB 14-1, “Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement),” reflecting new rules that would change the accounting for certain convertible debt instruments, which includes our 3.25% Notes. Under these new rules, which are effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years, an issuer of a convertible debt instrument that may be settled entirely or partially in cash upon conversion will be required to account for the liability and equity components of the instrument separately. The debt component will be recorded at an estimated fair value, as of the issuance date, of a similar debt instrument without the conversion feature, and the difference between the proceeds for the convertible debt and the amount reflected as a debt liability will be recorded as additional paid-in capital. As a result, the debt will be treated as if it had been issued at a discount and will subsequently be accreted through interest expense to its par value over its expected life, with a rate of interest that reflects the issuer’s nonconvertible debt borrowing rate. Due to the requirement to accrete the debt to its par value, which increases the debt component on which interest expense is computed, we expect to incur approximately $18 million of additional, non-cash interest charges in 2009, increasing to approximately $28 million in 2014.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We own and lease properties totaling approximately 1 million acres in West Virginia, Kentucky, Virginia, Pennsylvania and Tennessee. In addition, certain of our owned or leased properties are leased or subleased to third-party tenants. Our current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. We generally have not obtained title insurance in connection with acquisitions of coal reserves. In some cases, the seller or lessor warrants property title. We have not required title confirmation in certain cases under long-standing lease agreements where we are now the current lessor and the lease covers property where mining has occurred previously. We currently own or lease the equipment that is utilized in mining operations. The following table describes the location and general character of our major existing facilities, exclusive of mines, coal preparation plants and their adjoining offices.

Administrative Offices:

Richmond, Virginia	Owned	Massey Corporate Headquarters
Julian, West Virginia	Owned	Massey Operational Headquarters

For a description of mining properties, see Item 1. Business, under the heading “Mining Operations” and “Coal Reserves

Item 3. Legal Proceedings

Shareholder Suits

On July 2, 2007, Manville Personal Injury Trust (“Manville”) filed a suit in the Circuit Court of Kanawha County, West Virginia (the “Circuit Court”), which suit was amended on December 14, 2007, styled as a shareholder derivative action asserting that it was a shareholder acting on our behalf. We were named as a nominal defendant. Each of the then members of our Board of Directors, certain of our officers and certain of our former directors and officers were named as defendants (“Manville Defendants”). The complaint alleged breach of fiduciary duties to us arising out of the Manville Defendants’ alleged failure to cause us to comply with applicable state and federal environmental and worker-safety laws and regulations. The complaint sought to recover unspecified damages in favor of us, appropriate equitable relief and an award to Manville, respectively, of the costs and expenses associated with these actions. On September 7, 2007, Mr. Vernon Mercier filed a similar action in the United States District Court, Southern District of West Virginia (the “District Court”), styled as a shareholder derivative action asserting that he is a shareholder acting on our behalf (the “Vernon Mercier Action”). We are named as a nominal defendant. Each of the then members of our Board of Directors and certain of our officers and one former officer were named as defendants (“Original Vernon Mercier Defendants”).

On May 20, 2008, the Circuit Court entered an order preliminarily approving a settlement agreement in the Manville action. A final settlement hearing was held on June 25, 2008, and, rejecting the objections of Mr. Mercier, on June 30, 2008, the Circuit Court entered a final order approving the settlement and dismissing the Manville action with prejudice. The settlement agreement requires us to make certain corporate governance changes and pay Manville’s counsel fees and expenses in the amount of $2,700,000 as compensation for professional services rendered and expenses incurred in the prosecution of the litigation. This payment was made on July 15, 2008. Mr. Mercier declined to appeal this ruling.

On December 5, 2008, Mr. Mercier filed an Amended Complaint in the District Court, adding new members of our Board of Directors and additional employees to the Original Vernon Mercier Defendants (collectively, the “Vernon Mercier Defendants”), restating his original claim and adding claims for breach of fiduciary duty in connection with approval of the settlement of the Manville action and our CEO’s compensation package and a purported failure to comply with the terms of the settlement of the Manville action. On February 27, 2009, the Vernon Mercier Defendants jointly moved to dismiss the Amended Complaint, contending that the settlement in the Manville action bars Mr. Mercier from continuing to prosecute his federal court action and that Mr. Mercier’s claims otherwise lack merit.

We and the Vernon Mercier Defendants have insurance coverage applicable to these matters. We believe these matters will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

Certain information regarding other legal proceedings required by this Item 3 is contained in Note 18, "Contingencies" to the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K and is incorporated herein by reference.

We are parties to a number of other legal proceedings, incident to our normal business activities. These matters include, but are not limited to, contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition.

We are also party to lawsuits and other legal proceedings related to the non-coal businesses previously conducted by Fluor Corporation (renamed Massey Energy Company) but now conducted by New Fluor. Under the terms of the Distribution Agreement entered into by New Fluor and us as of November 30, 2000, in connection with the Spin-Off of New Fluor, New Fluor agreed to indemnify us with respect to all such legal proceedings and has assumed their defense.

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

There were no matters submitted to a vote of security holders through a solicitation of proxies or otherwise during the fourth quarter of the fiscal year ended December 31, 2008.

Part II

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

Common Stock

Common Stock is listed on the New York Stock Exchange ("NYSE") and trades under the symbol MEE. As of February 17, 2009, there were 85,492,888 shares outstanding and approximately 6,866 shareholders of record of Common Stock.

The following table sets forth the high and low sales prices per share of Common Stock on the NYSE for the past two years, based upon published financial sources, and the dividends declared on each share of Common Stock for the quarter indicated.

		High		Low		Dividends
Fiscal Year 2007						
Quarter ended March 31, 2007	$	26.35	$	21.55	$	0.04
Quarter ended June 30, 2007	$	30.73	$	23.97	$	0.04
Quarter ended September 30, 2007	$	26.80	$	16.01	$	0.04
Quarter ended December 31, 2007	$	37.99	$	21.49	$	0.05
Fiscal Year 2008						
Quarter ended March 31, 2008	$	44.00	$	26.22	$	0.05
Quarter ended June 30, 2008	$	95.70	$	35.33	$	0.05
Quarter ended September 30, 2008	$	94.09	$	31.15	$	0.05
Quarter ended December 31, 2008	$	35.00	$	10.05	$	0.06

Dividends

On February 17, 2009, our board of directors declared a dividend of $0.06 per share, payable on March 31, 2009, to shareholders of record on March 17, 2009.

Our current dividend policy anticipates the payment of quarterly dividends in the future. Our Board of Directors increased the regular quarterly dividend to $0.06 per share in the fourth quarter of 2008. The ABL Facility and our 6.875% senior notes due 2013 (the "6.875% Notes") contain provisions that restrict us from paying dividends in excess of certain amounts. The ABL Facility limits the payment of dividends to $50 million annually on Common Stock. The 6.875% Notes limit the payment of dividends to $25 million annually on Common Stock, plus the availability in the Restricted Payments Baskets (as defined in the Indenture governing the 6.875% Notes). In addition, dividends can be paid only so long as no default exists under the ABL Facility or the 6.875% Notes, as the case may be, or would result thereunder from paying such dividend. There are no other restrictions, other than those set forth under the corporate laws of the State of Delaware, where we are incorporated, on our ability to declare and pay dividends. The declaration and payment of dividends to holders of Common Stock will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, and capital requirements.

Convertible Debt Securities

Our 4.75% convertible senior notes due 2023 (the "4.75% Notes") are convertible by holders into shares of Common Stock during certain periods under certain circumstances. None of the 4.75% Notes were eligible for conversion at December 31, 2008. If all of the notes outstanding at December 31, 2008 had been eligible and were converted, we would have been required to issue 3,610 shares of Common Stock. In addition, holders of the 4.75% Notes may require us to purchase all or a portion of their 4.75% Notes on May 15, 2009, May 15, 2013, and May 15, 2018. For purchases on May 15, 2013 or May 15, 2018, we may, at our option, choose to pay the purchase price in cash or in shares of Common Stock or any combination thereof. In June 2008, $660,000 of principal amount of the 4.75% Notes was converted into 34,037 shares of Common Stock. No other conversions occurred during the year. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of the conversion and redemption features of the 4.75% Notes.

Our 2.25% convertible senior notes due 2024 (the “2.25% Notes”) are convertible by holders into shares of Common Stock during certain periods under certain circumstances. None of the 2.25% Notes were eligible for conversion at December 31, 2008. If all of the notes outstanding at December 31, 2008 had been eligible and were converted, we would have been required to issue 287,113 shares of Common Stock. No conversions occurred during the year. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 2.25% Notes.

The 3.25% Notes are convertible under certain circumstances and during certain periods into (i) cash, up to the aggregate principal amount of the 3.25% Notes subject to conversion and (ii) cash, Common Stock or a combination thereof, at our election in respect to the remainder (if any) of our conversion obligation. As of December 31, 2008, the price per share of Common Stock had not reached the specified threshold for conversion. No conversions occurred during the year. See Note 6 to the Notes to Consolidated Financial Statements for further discussion of conversion features of the 3.25% Notes.

Repurchase Program

On November 14, 2005, our Board of Directors authorized a stock repurchase program (the “Repurchase Program”), authorizing us to repurchase shares of Common Stock. We may repurchase Common Stock from time to time, as determined by authorized officers, up to an aggregate amount not to exceed $500 million (excluding commissions) with free cash flow as existing financing covenants may permit. Existing covenants currently allow for up to approximately $611 million of share repurchases. As of December 31, 2008, we had $420 million available under the current authorization. The stock repurchases may be conducted on the open market, through privately negotiated transactions, through derivative transactions or through purchases made in accordance with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended (“Exchange Act”), in compliance with the SEC’s regulations and other legal requirements. The Repurchase Program does not require us to acquire any specific number of shares and may be terminated at any time. Through December 31, 2008, 2,874,800 shares have been repurchased at an average price of $27.80 per share and classified as Treasury stock. All of the 2,874,800 shares held as Treasury stock were issued as part of the 4,370,000 shares of Common Stock which we publicly offered and sold in August 2008. No additional share repurchases have been made since that time.

Common Stock Offering Program

On February 3, 2009, pursuant to Rule 424(b)(5),we filed a prospectus supplement with the Securities and Exchange Commission (“SEC”) allowing us to sell up to 5.0 million shares of Common Stock from time to time in our discretion. The proceeds from any shares of Common Stock sold will be used for general corporate purposes, which may include funding for acquisitions or investments in business, products, technologies, and repurchases and repayment of our indebtedness.

Transfer Agent and Registrar

The transfer agent and registrar for Common Stock is Wells Fargo Shareowner Services, 161 North Concord Exchange, South St. Paul, Minnesota 55075, toll free (800) 689-8788.

Item 6. Selected Financial Data

SELECTED FINANCIAL DATA[1]

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(In millions, except per share, per ton, and number of employees amounts)				
CONSOLIDATED STATEMENT OF INCOME DATA:					
Produced coal revenue	$ 2,559.9	$ 2,054.4	$ 1,902.3	$ 1,777.7	$ 1,456.7
Total revenue	2,989.8	2,413.5	2,219.9	2,204.3	1,766.6
Income (Loss) before interest and income taxes	133.2	179.7	111.0	(20.9)	46.2
Income (Loss) before cumulative effect of accounting change	56.2	94.1	41.6	(101.6)	13.9
Net income (loss)	56.2	94.1	41.0	(101.6)	13.9
Income (Loss) per share - Basic [1]					
Income (Loss) before cumulative effect of accounting change	$ 0.69	$ 1.17	$ 0.51	$ (1.33)	$ 0.18
Net income (loss)	$ 0.69	$ 1.17	$ 0.50	$ (1.33)	$ 0.18
Income (Loss) per share - Diluted [1]					
Income (Loss) before cumulative effect of accounting change	$ 0.68	$ 1.17	$ 0.51	$ (1.33)	$ 0.18
Net income (loss)	$ 0.68	$ 1.17	$ 0.50	$ (1.33)	$ 0.18
Dividends declared per share	$ 0.21	$ 0.17	$ 0.16	$ 0.16	$ 0.16
CONSOLIDATED BALANCE SHEET DATA:					
Working capital	$ 731.3	$ 522.6	$ 445.2	$ 670.8	$ 458.4
Total assets	3,675.8	2,860.7	2,740.7	2,986.5	2,650.9
Long-term debt	1,463.6	1,102.7	1,102.3	1,102.6	900.2
Shareholders' equity [2]	1,036.6	784.0	697.3	841.0	776.9
OTHER DATA:					
EBIT [3]	$ 133.2	$ 179.7	$ 111.0	$ (20.9)	$ 46.2
EBITDA [3]	$ 390.6	$ 425.7	$ 341.5	$ 213.6	$ 270.8
Average cash cost per ton sold [4]	$ 48.53	$ 43.10	$ 42.33	$ 35.62	$ 30.50
Produced coal revenue per ton sold	$ 62.50	$ 51.55	$ 48.71	$ 42.02	$ 36.02
Capital expenditures	$ 736.5	$ 270.5	$ 298.1	$ 346.6	$ 347.2
Produced tons sold	41.0	39.9	39.1	42.3	40.4
Tons produced	41.1	39.5	38.6	43.1	42.0
Number of employees	6,743	5,407	5,517	5,709	5,034

(1) In accordance with accounting principles generally accepted in the United States (“GAAP”), the effect of certain dilutive securities was excluded from the calculation of the diluted income (loss) per common share for the years ended December 31, 2008, 2007, 2006, 2005, and 2004, as such inclusion would result in antidilution.

(2) Certain accounting pronouncements adopted in 2007 and 2006 affect the comparability of the 2007 and 2006 financial statements to prior years. The adoption of FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109” on January 1, 2007 increased equity by $5.2 million (see Note 7 to the Notes to Consolidated Financial Statements for more information). The adoption of Emerging Issues Task Force Issue No. 04-6, “Accounting for Stripping Costs Incurred During Production in the Mining Industry” on January 1, 2006 decreased equity by $93.8 million and the adoption of SFAS No. 158, “Employer’s Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)” on December 31, 2006 decreased equity by $40.2 million (see Notes 5, 10 and 11 to the Notes to Consolidated Financial Statements for more information).

(3) EBIT is defined as Income (Loss) before interest and taxes. EBITDA is defined as Income (Loss) before interest and taxes before deducting Depreciation, depletion, and amortization ("DD&A"). Although neither EBIT nor EBITDA are measures of performance calculated in accordance with GAAP, we believe that both measures are useful to an investor in evaluating us because they are widely used in the coal industry as measures to evaluate a company's operating performance before debt expense and as a measure of its cash flow. Neither EBIT nor EBITDA purport to represent operating income, net income or cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance calculated in accordance with GAAP. In addition, because neither EBIT nor EBITDA are calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Net income to EBIT and to EBITDA.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
			(In millions)		
Net income (loss)	$ 56.2	$ 94.1	$ 41.0	$ (101.6)	$ 13.9
Cumulative effect of accounting change, net of tax	-	-	0.6	-	-
Income tax expense(benefit)	4.1	35.4	3.4	26.2	(19.5)
Net interest expense and loss on short-term investment	72.9	50.2	66.0	54.5	51.8
EBIT	133.2	179.7	111.0	(20.9)	46.2
Depreciation, depletion and amortization	257.4	246.0	230.5	234.5	224.6
EBITDA	$ 390.6	$ 425.7	$ 341.5	$ 213.6	$ 270.8

(4) Average cash cost per ton is calculated as the sum of Cost of produced coal revenue and Selling, general and administrative expense ("SG&A") (excluding DD&A), divided by the number of produced tons sold. Although Average cash cost per ton is not a measure of performance calculated in accordance with GAAP, we believe that it is useful to investors in evaluating us because it is widely used in the coal industry as a measure to evaluate a company's control over its cash costs. Average cash cost per ton should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP. In addition, because Average cash cost per ton is not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. The table below reconciles the GAAP measure of Total costs and expenses to Average cash cost per ton.

	Year Ended December 31,									
	2008		2007		2006		2005		2004	
	(In millions, except per ton amounts)									
	$	per ton	$	per ton	$	per ton	$	per ton	$	per ton
Total costs and expenses	$2,856.6		$2,233.8		$2,108.8		$2,225.2		$1,720.4	
Less: Freight and handling costs	306.4		167.6		156.5		150.9		148.8	
Less: Cost of purchased coal revenue	28.5		95.2		62.6		112.6		104.1	
Less: Depreciation, depletion and amortization	257.4		246.0		230.5		234.5		224.6	
Less: Other expense	3.2		7.3		6.2		8.0		9.5	
Less: Litigation charge	250.1		-		-		-		-	
Less: Loss on financing transactions	0.5		-		-		212.4		-	
Less: Net change in fair value of derivative instruments	22.6		-		-		-		-	
Average cash cost	$1,987.9	$48.53	$1,717.7	$43.10	$1,653.0	$42.33	$1,506.8	$35.62	$1,233.4	$30.50

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

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") is intended to help the reader understand Massey Energy Company, our operations and our present business environment. MD&A is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes thereto contained in Item 8 of this report. From time to time, we may make statements that may constitute "forward-looking statements" within the meaning of the "safe-harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. Please see "Forward-Looking Statements" on page i hereto and are incorporated herein and the risk factors that may cause such a difference, which are set forth in Item 1A. Fisk Factors and are incorporated herein.

Executive Overview

We operate coal mines and processing facilities in Central Appalachia, which generate revenues and cash flow through the mining, processing and selling of steam and metallurgical grade coal, primarily of low sulfur content. We also generate income and cash flow through other coal-related businesses. Other revenue is obtained from royalties, rentals, gas well revenues, gains on the sale of non-strategic assets and miscellaneous income.

We reported net income for the year ended December 31, 2008 of $56.2 million, or $0.68 per diluted share, compared to net income for 2007 of $94.1 million, or $1.17 per diluted share. Net income in 2008 included pre-tax charges of $250.1 million related to the litigation with Wheeling-Pittsburgh Steel Corporation ("Wheeling-Pittsburgh"), pre-tax gains totaling $32.4 million related to asset and reserve exchanges with third-parties and a $22.6 million non-cash pre-tax charge to recognize the net unrealized losses on certain coal contracts that qualify as derivatives. Net income in 2007 included pre-tax gains totaling approximately $10.3 million related to a reserve exchange with a third-party, $33.6 million related to a favorable decision on our appeal of the previous jury decision in the Harman lawsuit and $6.7 million on the sale of a mineral rights override, offset by a $20.0 million non-tax deductible penalty related to a settlement with EPA.

Produced tons sold were 41.0 million in 2008, compared to 39.9 million in 2007. Shipments of metallurgical coal improved significantly in 2008 over 2007 as demand for this type of coal, especially in the export market, increased during 2008, allowing certain quality coal to be shifted from the utility to the metallurgical market. Production increased as new mines were started in 2008 as part of our expansion plan. We produced 41.1 million tons during 2008, compared to 39.5 million tons produced in 2007.

During 2008, Produced coal revenue increased by 25% over the prior year as we benefited from higher coal sales prices for both domestic and export sales secured in new coal sales agreements as lower-priced contracts expired and we shipped a larger percentage of higher-priced metallurgical tons in 2008. Our average Produced coal revenue per ton sold in 2008 increased by 21.2% to $62.50 compared to $51.55 in 2007 and by 73.5% over a five-year period compared to $36.02 in 2004. Our average Produced coal revenue per ton in 2008 for metallurgical tons sold increased by 33.9% to $97.07 from $72.49 in 2007.

We experienced a significant increase in costs during the past 5-year period, with Average cash cost per ton sold increasing from $30.50 in fiscal 2004 to $48.53 in fiscal 2008 (a reconciliation of these non-GAAP figures is presented in footnote 4 of Item 6. Selected Financial Data). The increased cost level is primarily due to indirect costs associated with compliance with new safety regulations, increased sales-related costs from the growth in average per ton realization, higher labor costs, mining supplies costs and litigation settlements.

Since we first announced our expansion and cost reduction plans in October 2007, we have opened 19 new mines and added 10 new underground miner sections at existing mines. In all, we have expanded production at 14 of our existing resource groups, started up the Inman Resource Group, re-started the Martin County and Coalgood Resource Groups, and provided new jobs for more than 1,300 additional members. By the end of 2008, our expansion work was continuing and was largely complete. A few projects that were initiated in 2008 remain to be completed in the first half of 2009, including the construction of a new processing plant at our Coalgood Resource Group and the addition of two new Superior highwall miners. Further expansion plans for 2009 have been deferred or cancelled in light of the changes in market conditions.

In November 2007, the Supreme Court of Appeals of West Virginia ("WV Supreme Court") reversed a jury decision in the Harman lawsuit, finding in favor of us and reversing the jury award. Subsequently, on January 24, 2008, the WV Supreme Court decided to rehear the case, which was re-argued on March 12, 2008. On April 3, 2008, the WV Supreme Court again reversed the judgment against certain of our subsidiaries and remanded the case with direction to enter an order dismissing the case, with prejudice, in its entirety. The Harman plaintiffs petitioned the United States Supreme Court to review the WV

Supreme Court’s dismissal of their claims. In December 2008, the United States Supreme Court (“U.S.

Supreme Court") agreed to review the case. Oral argument before the U.S. Supreme Court is scheduled for March 3, 2009. The U.S. Supreme Court could affirm the dismissal of the case by the WV Supreme Court or direct the WV Supreme Court to rehear the case. If the WV Supreme Court, which is comprised of five justices, rehears the case, the matter would not be heard by the same five justices who heard the matter in April 2008. The justices of the reconfigured WV Supreme Court could dismiss the plaintiffs' claims again, or reach some different result, including a reinstatement of the original verdict against us with interest.

On May 22, 2008, the WV Supreme Court decided not to hear an appeal of the verdicts against us or our subsidiary Central West Virginia Energy Company ("CWVE") that awarded damages in favor of Wheeling-Pittsburgh and Mountain State Carbon, LLC in the amount of $219.9 million, comprising $119.9 million compensatory and $100 million punitive damages (plus an additional $24 million of pre-judgment interest). On December 1, 2008, the United States Supreme Court declined to accept the petitions for certiorari filed on behalf of us and CWVE. On December 4, 2008, we paid the total amount of $267.4 million, which represented the entire judgment against us and CWVE, including all applicable interest payments.

On August 12, 2008, we issued in a registered underwritten public offering $690 million of 3.25% convertible senior notes due 2015, resulting in net proceeds of approximately $674.1 million. The 3.25% Notes are our fully registered, unsecured obligations, rank equally with all of our other unsecured senior indebtedness and are guaranteed by substantially all of our current and future operating subsidiaries. Interest is payable semiannually on August 1 and February 1 of each year. Also on August 12, 2008, we completed a registered underwritten public offering of 4,370,000 shares of Common Stock (which included the re-issuance of 2,874,800 Treasury stock shares) at a public offering price of $61.50 per share, resulting in net proceeds of $258.2 million. We used the proceeds from the concurrent Common Stock and the convertible notes offerings to purchase a portion of our 6.625% Notes in connection with the 6.625% Notes consent solicitation and tender offer and for general corporate purposes.

On August 19, 2008, we settled with holders of $311.5 million of the $335 million outstanding of the 6.625% Notes, representing approximately 93% of the outstanding 6.625% Notes, who tendered their 6.625% Notes pursuant to our tender offer for the 6.625% Notes. As a result of the receipt of consents of approximately 93% of the outstanding 6.625% Notes, we received the requisite consents to execute a supplemental indenture relating to the 6.625% Notes, which eliminated substantially all of the restrictive covenants in the 6.625% Notes' indenture. On September 3, 2008, we settled with holders of an additional $1.6 million of the 6.625% Notes, who tendered their 6.625% Notes after the consent solicitation deadline.

On September 16, 2008, The Reserve Primary Fund ("Primary Fund") reported a net asset value of $0.97 per share as a result of the Primary Fund's valuing at zero its holdings of debt securities issued by Lehman Brothers Holdings, Inc., which filed for bankruptcy on September 15, 2008. The Primary Fund suspended redemptions and subsequently announced that it would be liquidated. As of September 16, 2008, we had an investment in the Primary Fund of $217.9 million. Based on our assessment of the Primary Fund's net asset value, the planned disbursement schedule of the Primary Fund's cash and the underlying securities, we determined that the approximate fair value of our investment as of September 30, 2008 was $211.4 million, and recorded a loss of $6.5 million. On October 31, 2008 and December 3, 2008, the Primary Fund made distributions to us of $110.7 million and $61.3 million, respectively, leaving an investment balance of $39.4 million. Subsequent to December 31, 2008, on February 20, 2009, the Primary Fund made an additional distribution to us of $14.5 million. We are currently unable to access our remaining cash invested with the Primary Fund. While we expect to receive substantially all of our remaining holdings in the Primary Fund during 2009, we cannot predict when this will occur or the actual amount we will eventually receive.

The continuing recession, credit crisis and related turmoil in the global financial system has had and may continue to have a negative impact on our business, financial condition and liquidity. We may face significant future challenges if conditions in the financial markets do not improve or continue to worsen. Worldwide demand for coal has been adversely impacted, particularly for our metallurgical grade coals, which we expect will have a negative effect on our revenues. The competitiveness of coal exported from the United States has been negatively impacted by strengthening of the U.S. dollar and the decline of freight costs of ocean going vessels allowing coal produced in more distant countries, such as Australia, to compete with U.S. exports in the Atlantic Basin. Moreover, volatility and disruption of financial markets could affect the creditworthiness of our customers and/or limit our customers' ability to obtain adequate financing to maintain operations and result in a further decrease in sales volume that could have a negative impact on our cash flows, results of operations or financial condition.

Results of Operations

2008 Compared with 2007

Revenues

(In thousands)	Year Ended December 31, 2008	2007	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 2,559,929	$ 2,054,413	$ 505,516	25%
Freight and handling revenue	306,397	167,641	138,756	83%
Purchased coal revenue	30,684	108,191	(77,507)	(72)%
Other revenue	92,779	83,278	9,501	11%
Total revenues	$ 2,989,789	$ 2,413,523	$ 576,266	24%

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2008 compared to 2007:

(In millions, except per ton amounts)	Year Ended December 31, 2008	2007	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.0	27.4	(0.4)	(1)%
Metallurgical	9.9	8.5	1.4	16%
Industrial	4.1	4.0	0.1	2%
Total	41.0	39.9	1.1	3%
Produced coal revenue per ton sold:				
Utility	$ 49.92	$ 45.18	$ 4.74	10%
Metallurgical	97.07	72.49	24.58	34%
Industrial	61.78	50.82	10.96	22%
Weighted average	62.50	51.55	10.95	21%

Shipments of metallurgical coal increased in 2008 compared to 2007, as demand for this type of coal, especially in the export market, increased during 2008, allowing certain quality coal to be shifted from the utility to the metallurgical market. Production increased as new mines were started in 2008 as part of our expansion plan. The average per ton sales price for utility coal continued to improve in 2008, attributable to prices contracted during a period of increased demand for utility coal in the United States. The higher demand resulted in shortages of certain quality utility coal, increasing the market prices of this coal, and allowing us to negotiate agreements containing higher-priced terms as lower-priced contracts expired.

Freight and handling revenue increased due to an increase in export tons sold from 4.8 million tons in 2007 to 8.1 million tons in 2008. In addition, during 2008 there was a significant increase in freight rates, including fuel surcharges during a large portion of the year.

Purchased coal revenue decreased mainly due to a decrease in purchased tons sold from 2.1 million in 2007 to 0.5 million in 2008.

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, joint venture revenue and other miscellaneous revenue. Other revenue for 2008 includes a pre-tax gain of $32.4 million on an exchange of coal reserves and other assets. In addition, railroad refund income was higher in 2008 than in 2007, offset by lower royalty earnings in 2008 compared to 2007. Other revenue for 2007 includes a pre-tax gain of $10.3 million on an exchange of coal reserves and $6.7 million on the sale of mineral rights override (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

(In thousands)	Year Ended December 31, 2008	2007	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,910,953	$ 1,641,774	$ 269,179	16%
Freight and handling costs	306,397	167,641	138,756	83%
Cost of purchased coal revenue	28,517	95,241	(66,724)	(70)%
Depreciation, depletion and amortization, applicable to:	-			
Cost of produced coal revenue	253,737	242,755	10,982	5%
Selling, general and administrative	3,590	3,280	310	9%
Selling, general and administrative	77,015	75,845	1,170	2%
Other expense	3,207	7,308	(4,101)	(56)%
Litigation charge	250,061	-	250,061	100%
Loss on financing transactions	538	-	538	100%
Net change in fair value of derivative instruments	22,552	-	22,552	100%
Total costs and expenses	$ 2,856,567	$ 2,233,844	$ 622,723	28%

Cost of produced coal revenue increased due to increased sales-related costs on higher produced coal revenues including production royalties and severance taxes, increased supplies costs including diesel fuel and explosives, higher labor costs, litigation settlements and higher indirect costs associated with compliance with new safety regulations. Supplies costs increased both due to a commodity driven inflationary increase and overall usage as the volume of produced tons sold increased from 39.9 million tons in 2007 to 41.0 million tons in 2008.

Freight and handling costs increased due to an increase in export tons sold from 4.8 million tons in 2007 to 8.1 million tons in 2008. In addition, during 2008 there was a significant increase in freight rates, including fuel surcharges during a large portion of the year.

Cost of purchased coal revenue decreased due to a decrease in purchased tons sold from 2.1 million in 2007 to 0.5 million in 2008.

Depreciation, depletion and amortization applicable to Cost of produced coal revenue increased due to impact of various of our capital projects which went into service during 2008.

Litigation charge represents the court award and associated interest for the Wheeling-Pittsburgh matter (see Note 18 in the Notes to Consolidated Financial Statements for further discussion).

Loss on financing transactions relates to $9.1 million fees incurred for the tender offer for our 6.625% Notes, offset by an $8.6 million gain recognized from the purchase of $19.0 million of our 3.25% Notes on the open market during 2008 (see Note 6 in the Notes to Consolidated Financial Statements for further discussion).

Net change in fair value of derivative instruments represents net unrealized losses of $22.6 million related to purchase and sales contracts that qualify as derivatives (see Note 15 in the Notes to Consolidated Financial Statements for further discussion).

Interest

Interest income remained comparable to prior year at $23.6 million as the current year decline in interest rates on Cash and cash equivalents was offset by higher cash balances on hand from August 2008 onward due to the debt and equity issuances in the third quarter and the recording of $7.0 million of interest income on the black lung excise tax refund. Interest expense primarily increased due to 2007 including a credit to interest expense of $11.4 million relating to interest which had previously been accrued on the Harman matter which was overturned by the WV Supreme Court in 2007 (see Note 18 in the Notes to Consolidated Financial Statements for further discussion). The remainder of the increase can be attributed $6.1 million included in interest expense for the write-off of debt issuance costs and the related interest rate swap balance due to the repurchase of the 6.625% Notes (see Note 6 in the Notes to Consolidated Financial Statements for further discussion).

Loss on short-term investment

Loss on short-term investment represents a *pro rata* share of the estimated loss in our investment in the Primary Fund of $6.5 million (see Note 16 to the Notes to Condensed Consolidated Financial Statements for further discussion).

Income Taxes

Income tax expense was $4.1 million for 2008 compared with a tax expense of $35.4 million for 2007. The income tax rates for 2008 and 2007 were favorably impacted by percentage depletion allowances and the usage of net operating loss carryforwards. The income tax rate in 2008 was negatively impacted by nondeductible penalties and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. Also impacting the 2008 income tax rate were favorable adjustments in connection with the election to forego bonus depreciation and claim a refund for alternative minimum tax credits. The income tax rate in 2007 was negatively impacted by a nondeductible EPA settlement and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. The 2007 rate was also favorably impacted by the adjustment of reserves in connection with the closing of a prior period audit by the IRS. Because of the discrete tax events occurring in 2008, the tax rate for 2008 may not be indicative of future tax rates.

2007 Compared with 2006

Revenues

(In thousands)	Year Ended December 31, 2007	2006	Increase (Decrease)	% Increase (Decrease)
Revenues				
Produced coal revenue	$ 2,054,413	$ 1,902,259	$ 152,154	8%
Freight and handling revenue	167,641	156,531	11,110	7%
Purchased coal revenue	108,191	70,636	37,555	53%
Other revenue	83,278	90,428	(7,150)	(8)%
Total revenues	$ 2,413,523	$ 2,219,854	$ 193,669	9%

The following is a breakdown, by market served, of the changes in produced tons sold and average produced coal revenue per ton sold for 2007 compared to 2006:

	Year Ended December 31,			
(In millions, except per ton amounts)	2007	2006	Increase (Decrease)	% Increase (Decrease)
Produced tons sold:				
Utility	27.4	27.7	(0.3)	(1)%
Metallurgical	8.5	7.8	0.7	9%
Industrial	4.0	3.6	0.4	11%
Total	39.9	39.1	0.8	2%
Produced coal revenue per ton sold:				
Utility	$ 45.18	$ 42.37	$ 2.81	7%
Metallurgical	72.49	69.20	3.29	5%
Industrial	50.82	53.13	(2.31)	(4)%
Weighted average	51.55	48.71	2.84	6%

Shipments of metallurgical and industrial coal increased in 2007 compared to 2006, mainly due to improved productivity at underground room and pillar mines resulting from lower turnover and a more stable workforce, and improved performance from the railroads shipping this coal. The average per ton sales price for utility coal continued to improve in 2007, attributable to prices contracted during a period of increased demand for utility coal in the United States. The higher demand resulted in shortages of certain quality utility coal, increasing the market prices of this coal, and allowed us to negotiate agreements containing higher price terms as lower-priced contracts expired. The decrease in average per ton sales price for the industrial market is mainly attributable to lower pricing on sales contracted for 2007 shipments.

Purchased coal revenue increased mainly due to an increase in purchased tons sold from 1.3 million in 2006 to 2.1 million in 2007, offset by a 4% decrease in revenue per ton. We purchase varying amounts of coal to supplement produced coal sales.

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, earnings from the sale and operation of a synfuel plant, joint venture revenue and other miscellaneous revenue. Other revenue for 2007 includes a pre-tax gain of $10.3 million on an exchange of coal reserves and $6.7 million on the sale of a mineral rights override. In addition, railroad refunds and royalty income were higher in 2007 than in 2006, offset by lower synfuel earnings in 2007 compared to 2006. Other revenue for 2006 includes a pre-tax gain of $30.0 million on the sale of our Falcon reserves (see Note 4 in the Notes to Consolidated Financial Statements for further discussion).

Costs

	Year Ended December 31,			
(In thousands)	2007	2006	Increase (Decrease)	% Increase (Decrease)
Costs and expenses				
Cost of produced coal revenue	$ 1,641,774	$ 1,599,092	$ 42,682	3%
Freight and handling costs	167,641	156,531	11,110	7%
Cost of purchased coal revenue	95,241	62,613	32,628	52%
Depreciation, depletion and amortization, applicable to:				
Cost of produced coal revenue	242,755	227,279	15,476	7%
Selling, general and administrative	3,280	3,259	21	1%
Selling, general and administrative	75,845	53,834	22,011	41%
Other expense	7,308	6,240	1,068	17%
Total costs and expenses	$ 2,233,844	$ 2,108,848	$ 124,996	6%

Cost of produced coal revenue increased due to increased sales-related costs on higher produced coal revenues including production royalties and severance taxes, increased supplies costs including diesel fuel and explosives, and higher indirect costs associated with compliance with new safety regulations. Supplies costs increased both due to a commodity driven inflationary increase and overall usage as the volume of produced tons sold increased from 39.1 million tons in 2006 to 39.9 million tons in 2007.

Cost of purchased coal revenue increased due to an increase in purchased tons sold from 1.3 million in 2006 to 2.1 million in 2007, offset by a 4% decrease in average cost of purchased coal per ton.

Selling, general and administrative expenses increased due to higher stock-based and performance-based compensation expenses due to increased stock price value in 2007 and attainment of more performance based compensation targets versus 2006.

Interest

Interest income increased due to higher cash and interest-bearing deposit balances during 2007 as compared to 2006. Interest expense decreased due to 2007 including a credit to interest expense of $11.4 million relating to the Harman matter (see Note 18 in the Notes to Consolidated Financial Statements for further discussion).

Income Taxes

Income tax expense was $35.4 million for 2007 compared with a tax expense of $3.4 million for 2006. The income tax rates for 2007 and 2006 were favorably impacted by percentage depletion allowances and the usage of net operating loss carryforwards. The income tax rate for 2007 was negatively impacted by a nondeductible EPA settlement and an increase in deferred tax asset valuation allowances related principally to federal net operating losses. Also impacting the 2007 income tax rate were favorable adjustments in connection with the closing of a prior period audit by the IRS. The income tax rate in 2006 was also favorably impacted by the adjustment of reserves in connection with the closing of a prior period audit by the IRS.

Liquidity and Capital Resources

At December 31, 2008, our available liquidity was $706.5 million, comprised of Cash and cash equivalents of $607.0 million and $99.5 million of availability from our asset-based revolving credit facility. We also have a $39.4 million investment in the Primary Fund, which is recorded in Short-term investment (see Note 16 in the Notes to Consolidated Financial Statements for further discussion). Our total debt-to-book capitalization ratio was 58.6% at December 31, 2008.

Debt was comprised of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 756,041	$ 755,401
3.25% convertible senior notes due 2015	671,000	-
6.625% senior notes due 2010	21,949	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	70	730
Capital lease obligations	6,912	8,823
Fair value hedge adjustment	-	(5,054)
Total debt	1,465,619	1,104,547
Amounts due within one year	(1,976)	(1,875)
Total long-term debt	$ 1,463,643	$ 1,102,672

See Note 6 in the Notes to Consolidated Financial Statements for further discussion of our debt and debt-related covenants.

Asset-Based Credit Facility

We maintain an asset-based revolving credit agreement, which provides for available borrowings, including letters of credit, of up to $175 million, depending on the level of eligible inventory and accounts receivable. The facility expires on May 15, 2010; however if the 6.625% Notes have been refinanced, defeased, or paid in full by May 15, 2010, the expiration date is extended to August 15, 2011. As of December 31, 2008, there were $75.5 million of letters of credit issued and there were $0 outstanding borrowings under this facility.

Debt Ratings

Moody's Investors Service ("Moody's") and Standard & Poor's Rating Services ("S&P") rate our long-term debt. As of December 31, 2008, our S&P outlook rating is Stable. Moody's outlook on all of our notes is Stable; our Long-Term Corporate Family Rating is B1.

Current Ratings:	Moody's	S&P
6.875% Notes	B2	BB-
3.25% Notes	NR	BB-
6.625% Notes	B2	NR
2.25% Notes	B2	BB-
4.75% Notes	B3	NR

NR - Not separately rated

Financing Transactions

On August 5, 2008, we commenced a consent solicitation and cash tender offer for any and all of the outstanding $335 million of 6.625% Notes and concurrently we commenced registered underwritten public offerings of convertible senior notes (the 3.25% Notes) and shares of Common Stock and announced our intention to use the proceeds of the offerings to purchase some or all of the 6.625% Notes in the tender offer and for general corporate purposes.

On August 19, 2008, we settled with holders of $311.5 million of the 6.625% Notes, representing approximately 93% of the outstanding 6.625% Notes, who tendered their 6.625% Notes pursuant to our consent solicitation and tender offer for the 6.625% Notes. The total consideration for these 6.625% Notes was $1,026.57 per $1,000 principal amount of the 6.625% Notes. The total consideration included a consent payment of $25 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

As a result of the consents of approximately 93% of the outstanding 6.625% Notes, we received the requisite consents to execute a supplemental indenture relating to the 6.625% Notes, which eliminated substantially all of the restrictive covenants in the 6.625% Notes' indenture. On September 3, 2008, we settled with holders of an additional $1.6 million of the 6.625% Notes, who tendered their 6.625% Notes after the consent solicitation deadline. The total consideration for these 6.625% Notes was $1,001.57 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

3.25% Notes

On August 12, 2008, we issued $690 million of 3.25% Notes in a registered underwritten public offering, resulting in net proceeds to us of approximately $674.1 million. The 3.25% Notes are guaranteed on a senior unsecured basis by substantially all of our current and future operating subsidiaries (the "Guarantors"). The 3.25% Notes and the guarantees rank equally with all of our and the Guarantors' existing and future senior unsecured indebtedness and rank senior to all of our and the Guarantors' indebtedness that is expressly subordinated to the 3.25% Notes and the guarantees, but are effectively subordinated to all of our and the Guarantors' existing and future senior secured indebtedness to the extent of the value of the assets securing the indebtedness and to all liabilities of our subsidiaries that are not Guarantors.

The 3.25% Notes bear interest at a rate of 3.25% per annum, payable semi-annually in arrears on August 1 and February 1 of each year, beginning on February 1, 2009. The 3.25% Notes will mature on August 1, 2015, unless earlier repurchased by us or converted.

The 3.25% Notes are convertible in certain circumstances during certain periods at an initial conversion rate of 11.4106 shares of Common Stock per $1,000 principal amount of 3.25% Notes (which represented an initial conversion price of approximately $87.64 per share), subject to adjustment in certain circumstances.

The 3.25% Notes are convertible under certain circumstances and during certain periods into (i) cash, up to the aggregate principal amount of the 3.25% Notes subject to conversion and (ii) cash, shares of Common Stock or a combination thereof, at our election in respect to the remainder (if any) of our conversion obligation. Subject to earlier repurchase, the 3.25% Notes will be convertible only in the following circumstances and to the following extent:

- during any calendar quarter, if the closing sale price of our shares of Common Stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price in effect on the last trading day of the immediately preceding calendar quarter;

- during the five consecutive business days immediately after any five consecutive trading day period (the "note measurement period") in which the average trading price per $1,000 principal amount of 3.25% Notes was equal to or less than 97% of the average conversion value of the 3.25% Notes during the note measurement period;

- if we make certain distributions on our shares of Common Stock or engage in certain transactions; and

- at any time from, and including, February 1, 2015 until the close of business on the second business day immediately preceding August 1, 2015.

The indenture governing the 3.25% Notes contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the trustee for the 3.25% Notes or the holders of not less than 25% in aggregate principal amount of the 3.25% Notes then outstanding may declare the unpaid principal of the 3.25% Notes and any accrued and unpaid interest thereon immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us, the principal amount of the 3.25% Notes together with any accrued and unpaid interest thereon will automatically become and be immediately due and payable.

Open Market Debt Repurchase

On November 6, 2008, we concluded an open market purchase, retiring $19.0 million of principal amount of the 3.25% Notes at a cost of $10.4 million, plus accrued interest resulting in a gain of $8.6 million recorded in Loss on financing transactions. Depending on market conditions and covenant restrictions, we may continue to make debt repurchases from time to time through open market purchases, private transactions or otherwise.

Common Stock Issuance

On August 12, 2008, we completed a registered underwritten public offering of 4,370,000 shares of Common Stock, which included re-issuing 2,874,800 shares of our Treasury stock, at a public offering price of $61.50 per share, resulting in proceeds to us of $258.2 million, net of underwriting fees. As discussed in Note 17 to the Notes to Consolidated Financial Statements, we used these proceeds and the proceeds of the concurrent 3.25% Notes offering to purchase a portion of the 6.625% Notes in connection with the 6.625% Notes consent solicitation and tender offer and for general corporate purposes.

Fair Value Hedge Adjustment

On December 9, 2005, we exercised our right to terminate our interest rate swap agreement, which was hedged against a portion of the 6.625% Notes. We paid a $7.9 million termination payment to the swap counterparty on December 13, 2005. The termination payment, which is reflected in the table above at December 31, 2007, as Fair value hedge adjustment, was being amortized into Interest expense through November 15, 2010, the maturity date of the 6.625% Notes. As discussed in Note 6 to the Notes to Consolidated Financial Statements under Financing Transactions, on August 19, 2008, we settled with holders of approximately 93% of the outstanding 6.625% Notes that were tendered pursuant to our consent solicitation and tender offer for the 6.625% Notes. As a result of the acceptance of the consent solicitation and tender offer of the 6.625% Notes, the remaining balance of the Fair value hedge adjustment ($4.2 million) was written off to Interest expense.

Cash Flow

Net cash provided by operating activities was $385.1 million for 2008 compared to $396.0 million for 2007. Cash provided by operating activities reflects Net income adjusted for non-cash charges and changes in working capital requirements.

Net cash utilized by investing activities was $776.5 million and $242.3 million for 2008 and 2007, respectively. The cash used in investing activities reflects capital expenditures in the amount of $736.5 million and $270.5 million for 2008 and 2007, respectively. These capital expenditures are for replacement of mining equipment, the expansion of mining and shipping capacity, and projects to improve the efficiency of mining operations. Included in these capital expenditures are $3.0 million of cash spent for the buyout of operating leases in both 2008 and 2007. Additionally, 2008 and 2007 included $6.0 million and $28.1 million, respectively, of proceeds provided by the sale of assets (see Note 4 to the Notes to Consolidated Financial Statements for further discussion).

Net cash provided by financing activities was $633.2 million for 2008 compared to net cash utilized of $27.7 million for 2007, respectively. Financing activities reflect changes in debt levels, common stock offerings, exercising of stock options, payments of dividends and cash receipts generated from sale-leaseback transactions. Financing activities for 2008 primarily reflects the $674.1 million of proceeds provided by the issuance of the 3.25% Notes, $258.2 million of proceeds provided by the issuance of Common Stock, $322.1 million utilized for the tender payment for the 6.625% Notes, and the $10.4 million utilized for the purchase of our 3.25% Notes on the open market discussed above. Financing activities for 2007 included $30 million for the repurchases of 1.5 million shares of Common Stock under the share repurchase program discussed below. We also generated $41.3 million from several sale-leaseback (operating leases) transactions of certain mining equipment in 2008, compared to $13.1 million of sale-leasebacks in 2007.

We believe that cash on hand, cash generated from operations and our borrowing capacity will be sufficient to meet our working capital requirements, scheduled debt payments, potential share repurchases and debt repurchases, anticipated dividend payments, expected settlements and final awards of outstanding litigation and anticipated capital expenditures including planned expansions (other than major acquisitions) for at least the next twelve months. Nevertheless, our ability to satisfy our debt service obligations, repurchase shares and debt, pay dividends, pay settlements and final awards of outstanding litigation, or fund planned capital expenditures including planned expansions, will substantially depend upon our future operating performance, which will be affected by prevailing economic conditions in the coal industry, debt covenants and financial, business and other factors, some of which are beyond our control. (See also "Concentration of Credit Risk and Major Customers" in Note 14 in the Notes to Consolidated Financial Statements.) We frequently evaluate potential acquisitions. In the past, we have funded acquisitions primarily with cash generated from operations. As a result of the cash needs we have described above and possible acquisition opportunities, in the future we may consider a variety of financing sources, including debt or equity financing. Currently, other than our asset-based revolving credit facility, we have no commitments for any additional financing. We cannot be certain that we can obtain additional financing on terms that we find acceptable, if at all, through the issuance of equity securities or the incurrence of additional debt. Additional equity financing may dilute our stockholders, and debt financing, if available, and may, among other things, restrict our ability to repurchase Common Stock, declare and pay dividends and raise future capital. If we are unable to obtain additional needed financing, it may prohibit us from making acquisitions, capital expenditures and/or investments, which could materially and adversely affect our prospects for long-term growth.

Common Stock Offering Program

On February 3, 2009, pursuant to Rule 424(b)(5),we filed a prospectus supplement with the Securities and Exchange Commission ("SEC") allowing us to sell up to 5.0 million shares of Common Stock from time to time in our discretion. The proceeds from any shares of Common Stock sold will be used for general corporate purposes, which may include funding for acquisitions or investments in business, products, technologies, and repurchases and repayment of our indebtedness.

Share Repurchases

The Board of Directors has authorized a total of $500 million (excluding commissions) to repurchase our common stock under our share repurchase program. Through December 31, 2008, 2,874,800 shares have been repurchased at an average price of $27.80 per share and classified as Treasury stock. All of the 2,874,800 shares held as Treasury stock were re-issued as part of the 4,370,000 shares of Common Stock which were offered and sold in an underwritten public offering in August 2008. As of December 31, 2008, we had $420 million available under the current authorization. We may repurchase shares of Common Stock from time to time in compliance with the SEC's regulations and other legal requirements, and subject to market conditions and other factors. The share repurchase program does not require us to acquire any specific number of shares and may be terminated at any time.

The following table summarizes information about shares of Common Stock that were purchased during the fourth quarter of 2008.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plan
October 1 through October 31	-	-	-	-
November 1 through November 30	-	-	-	-
December 1 through December 31	-	-	-	-
Total	-		-	27,667,984 (1)

(1) Calculated using $420 million that may yet be purchased under our share repurchase program and $15.18, the closing price of Common Stock as reported on the New York Stock Exchange on January 31, 2009.

Contractual Obligations

We have various contractual obligations that are recorded as liabilities within the Consolidated Financial Statements in this Annual Report on Form 10-K. Other obligations, such as certain purchase commitments, operating lease agreements, and other executory contracts are not recognized as liabilities within the Consolidated Financial Statements but are required to be disclosed. The following table is a summary of our significant obligations as of December 31, 2008 and the future periods in which such obligations are expected to be settled in cash. The table does not include current liabilities accrued within the Consolidated Financial Statements, such as Accounts payable and Payroll and employee benefits.

	Payments Due by Period (In Thousands)				
	Total	**Within 1 Year**	**1-3 Years**	**3-5 Years**	**Beyond 5 Years**
Long-term debt (1)	$ 1,875,465	$ 75,732	$ 171,838	$ 908,556	$ 719,339
Capital lease obligations (2)	7,415	2,285	5,082	25	23
Operating lease obligations (3)	292,595	71,237	126,677	75,831	18,850
Coal lease obligations (4)	159,960	18,906	36,379	31,806	72,869
Purchased coal obligations (5)	145,419	145,419	-	-	-
Other purchase obligations (6)	333,095	323,290	7,555	2,250	-
Total Obligations	$ 2,813,949	$ 636,869	$ 347,531	$ 1,018,468	$ 811,081

(1) Long-term debt obligations reflect the future interest and principal payments of our fixed rate senior unsecured notes outstanding as of December 31, 2008. See Note 6 to the Notes to Consolidated Financial Statements for additional information.

(2) Capital lease obligations include the amount of imputed interest over the terms of the leases. See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(3) See Note 13 to the Notes to Consolidated Financial Statements for additional information.

(4) Coal lease obligations include minimum royalties paid on leased coal rights. Certain coal leases do not have set expiration dates but extend until completion of mining of all merchantable and mineable coal reserves. For purposes of this table, we have generally assumed that minimum royalties on such leases will be paid for a period of 20 years.

(5) Purchased coal obligations represent commitments to purchase coal from external production sources under firm contracts as of December 31, 2008.

(6) Other purchase obligations primarily include capital expenditure commitments for surface mining and other equipment as well as purchases of materials and supplies. We have purchase agreements with vendors for most types of operating expenses. However, our open purchase orders (which are not recognized as a liability until the purchased items are received) under these purchase agreements, combined with any other open purchase orders, are not material and are excluded from this table. Other purchase obligations also include contractual commitments under transportation contracts. Since the actual tons to be shipped under these contracts are not set and will vary, the amount included in the table reflects the minimum payment obligations required by the contracts.

Additionally, we have liabilities relating to pension and other postretirement benefits, work related injuries and illnesses, and mine reclamation and closure. As of December 31, 2008, payments related to these items are estimated to be:

Payments Due by Years (In Thousands)		
Within 1 Year	**1 - 3 Years**	**3 - 5 Years**
$50,880	$81,670	$99,148

Our determination of these noncurrent liabilities is calculated annually and is based on several assumptions, including then-prevailing conditions, which may change from year to year. In any year, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. Moreover, in particular for periods after 2008, the estimates may change from the amounts included in the table, and may change significantly, if assumptions change to reflect changing conditions. These assumptions are discussed in the Notes to Consolidated Financial Statements and in Critical Accounting Estimates and Assumptions of this Management's Discussion and Analysis of Financial Condition and Results of Operations section.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for workers' compensation programs, various insurance contracts and other obligations. At December 31, 2008, we had $120.5 million of letters of credit outstanding of which $45.0 million was collateralized by $46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $75.5 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2008.

On January 22, 2008, a settlement was reached regarding our previously reported disagreement and protest of a new actuarial methodology being applied by the Office of Workers' Claims ("OWC") for the Commonwealth of Kentucky in determining levels of surety against potential future claims. The settlement resulted in the dismissal of our cases pending in the Franklin County Circuit Court of Kentucky and required us to post additional surety of $11.5 million for the 2006 and 2007 assessments against potential claims. That additional surety requirement was satisfied with the posting of a letter of credit issued under our asset-based lending arrangement.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2008, we had $330.2 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $321.1 million, and other miscellaneous obligation bonds of $9.1 million. Outstanding surety bonds of $46.1 million are secured with letters of credit. In addition, in December 2008, a $50.0 million appeal bond in the Wheeling-Pittsburgh legal matter was used to pay the plaintiff following the U.S. Supreme Court decision to not hear our appeal of the matter (see Note 18 to Notes to Consolidated Financial Statements for further discussion).

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

Certain Trends and Uncertainties

Our inability to satisfy contractual obligations may adversely affect profitability.

From time to time, we have disputes with customers over the provisions of sales agreements relating to, among other things, coal pricing, quality, quantity, delays and force majeure declarations. Our inability to satisfy contractual obligations could result in the purchase of coal from third-party sources to satisfy those obligations, the negotiation of settlements with customers, which may include price reductions, the reduction of commitments or the extension of the time for delivery, and customers terminating contracts, declining to do future business with us, or initiating claims against us. Recently, several of our customers have notified us of losses they have allegedly incurred due to alleged shortfalls in contracted coal shipments. We believe that factors beyond our control or responsibility account for most or all of the shortfalls. However, we may not be able to resolve all of these disputes, or other disputes with customers over sales agreements, in a satisfactory manner, which could result in the payment of substantial damages or otherwise harm our reputation and our relationships with our customers (see Note 18 to the Notes to Consolidated Financial Statements for further discussion).

The global financial crisis may have an impact on our business, financial condition and liquidity in ways that we currently cannot predict.

The continuing credit crisis and related turmoil in the global financial markets has had and may continue to have an impact on our business, financial condition and liquidity.

We are currently unable to access our remaining cash invested with the Primary Fund, a money market fund that has suspended redemptions and is being liquidated. We had invested $217.9 million in this fund, which had a fair value of $211.4 million at September 30, 2008. On October 31, 2008 and December 3, 2008, the Primary Fund made distributions to us of $110.7 million and $61.3 million, respectively, leaving an investment balance of $39.4 million. Subsequent to December 31, 2008, on February 20, 2009, the Primary Fund made an additional distribution to us of $14.5 million. While we expect to receive substantially all of our remaining holdings in this fund during 2009, we cannot predict when this will occur or the actual amount we will eventually receive.

The current difficult economic market environment is causing contraction in the availability of credit in the marketplace. In addition to the impact that the global financial crisis has already had on us, we may face significant challenges if conditions in the financial markets do not improve or continue to worsen. For example, an extension of the credit crisis to other industries could adversely impact overall demand, particularly for our metallurgical grade coals, which could have a negative effect on our revenues. In addition, our ability to access the capital markets may be severely restricted at a time when we would like, or need, to access these markets, which could have an impact on our flexibility to react to changing economic and business conditions and could potentially reduce our sources of liquidity. Moreover, volatility and disruption of financial markets could limit customers' ability to obtain adequate financing to maintain operations and result in a decrease in sales volume that could have a negative impact on our cash flows, results of operations or financial condition.

Capital and credit market volatility may affect our costs of borrowing.

While we maintain business relationships with a diverse group of financial institutions, their continued viability is not certain. Difficulties at one or more such financial institutions could lead them not to honor their contractual credit commitments under our ABL Facility or to renew their extensions of credit or provide new sources of credit. Recently, the capital and credit markets have been highly volatile as a result of adverse conditions that have caused the failure and near failure of a number of large financial services companies. If the capital and credit markets continue to experience volatility and the availability of funds remains limited, we may incur increased costs associated with borrowings. While we believe that recent governmental and regulatory actions should reduce the risk of a further deterioration or systemic contraction of capital and credit markets, there can be no certainty that our liquidity will not be negatively impacted by adverse conditions in the capital and credit markets.

We may be adversely affected by a decline in the financial condition and creditworthiness of our customers.

In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or guarantees or, ultimately, a suspension of credit privileges. The creditworthiness of customers can limit who we can do business with and at what price. For the year ended December 31, 2008, approximately 97% of coal sales volume was pursuant to long-term contracts. We anticipate that in 2009, the percentage of our sales pursuant to long-term contracts will be comparable with the percentage of our sales for 2008. For 2009, approximately 60% of our projected sales tons are contracted to be sold to our 10 largest customers, with our largest customer currently contracted to purchase approximately 26% of our projected 2009 sales. Many of our customers, including many of our large customers, are experiencing lower demand and weaker financial performance due to the economic downturn. If one or more of our larger customers fails to make payment for our sales to them, there could be an adverse effect on our cash flows, results of operations or financial condition.

We have contracts to supply coal to energy trading and brokering companies who resell the coal to the ultimate users. We are subject to being adversely affected by any decline in the financial condition and creditworthiness of these energy trading and brokering companies. In addition, as one of the largest suppliers of metallurgical coal to the United States steel industry and a significant exporter to foreign users, we are subject to being adversely affected by any decline in the financial condition or production volume of both United States and foreign steel producers.

Some of our customers may be unwilling to take all of their contracted tonnage or may request a price lower than their contracted price.

Many of our customers are experiencing lower demand for their products and services due to the current severe economic downturn, particularly customers in the steel industry. Several of our steel customers have announced production cutbacks in excess of 30% of their normal operating capacity and some of our utility and industrial customers have announced smaller cutbacks. The lower demand for our customers' products results in lower demand for the coal used in their manufacturing process. Some of our customers have requested and others may request deferrals of shipments, reduction of contracted sales tonnages and/or reduction of the contracted sales price. If we believe it is in our best interests to agree to any reduction in contracted price and/or tons from our customers, there could be an adverse effect on our cash flows, results of operations or financial condition.

Critical Accounting Estimates and Assumptions

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts. These estimates and assumptions are based on information available as of the date of the financial statements. Significant changes to the estimates and assumptions used in determining certain liabilities described below could introduce substantial volatility to our costs. The following critical accounting estimates and assumptions were used in the preparation of the financial statements:

Defined Benefit Pension Plans

The estimated cost and benefits of non-contributory defined benefit pension plans are determined by independent actuaries, who, with management's review and approval, use various actuarial assumptions, including discount rate, future rate of increase in compensation levels and expected long-term rate of return on pension plan assets. The discount rate is an estimate of the current interest rate at which the applicable liabilities could be effectively settled as of the measurement date. In estimating the discount rate, forecasted cash flows were discounted using each year's associated spot interest rate on high quality fixed income investments. At December 31, 2008 and 2007, the discount rate used to determine defined benefit pension liability was 6.10% and 6.50%, respectively. The impact of lowering the discount rate 0.25% for 2008 would have increased the 2008 net periodic pension expense by approximately $1.8 million. The rate of increase in compensation levels is determined based upon our long-term plans for such increases. The rate of increase in compensation levels used was 4.0% for the years ended December 31, 2008 and 2007. The expected long-term rate of return on pension plan assets is based on long-term historical return information and future estimates of long-term investment returns for the target asset allocation of investments that comprise plan assets. The expected long-term rate of return on plan assets used to determine expense in each period was 8.0% for each of the years ended December 31, 2008, 2007 and 2006, respectively. A 0.5% decrease in the expected long-term rate of return assumption would have increased the 2008 net periodic pension expense by approximately $1.4 million. We expect our 2009 pension costs related to our qualified non-contributory pension plan to significantly increase as a result of investment losses on the pension assets during 2008. The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions might materially affect our financial position or results of operations. See Note 5 to the Notes to Consolidated Financial Statements for further discussion on our pension plans.

We have an internal investment committee ("Investment Committee") that sets investment policy for the pension assets, selects and monitors investment managers and monitors asset allocation. In January 2009, the Investment Committee revised the target pension assets allocation for an interim period given the recent volatility and uncertainty in the equity securities markets. The targeted asset allocation for equity securities was revised to 25% of current plan assets compared to 54.2% of the pension assets invested in equity securities at December 31, 2008, with the balance of plan assets now to be invested in cash, cash equivalents and debt securities. The plan asset portfolio has been rebalanced consistent with the revised targeted asset allocation strategy. The rebalancing will not impact the 2009 pension expense, however the investment returns on pension assets from this rebalancing could materially impact pension expense in future periods.

Coal Workers' Pneumoconiosis

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and various states' statutes, for the payment of medical and disability benefits to eligible recipients resulting from occurrences of coal workers' pneumoconiosis disease (black lung). An annual evaluation is prepared by independent actuaries, who, after review and approval by management, use various assumptions regarding disability incidence, medical costs trend, cost of living trend, mortality, death benefits, dependents and interest rates. We record expense related to this obligation using the service cost method. At December 31, 2008 and December 31, 2007, the discount rate used to determine the black lung liability was 6.10%

and 6.50%, respectively. Included in Note 11 to the Notes to Consolidated Financial Statements is a medical cost trend and cost of living trend sensitivity analysis.

Workers' Compensation

Our operations have workers' compensation coverage through a combination of either self-insurance, participation in a state run program, or commercial insurance. We accrue for the self-insured liability by recognizing cost when it is probable that the liability has been incurred and the cost can be reasonably estimated. To assist in the determination of this estimated liability we utilize the services of third-party administrators who derive claim reserves from historical experience. These third parties provide information to independent actuaries, who after review and consultation with management with regards to actuarial assumptions, including discount rate, prepare an evaluation of the self-insured liabilities. At December 31, 2008 and December 31, 2007, the discount rate used to determine the self-insured workers' compensation liability obligation was 5.00%. A decrease in the assumed discount rate increases the workers' compensation self-insured liability and related expense. Actual experience in settling these liabilities could differ from these estimates, which could increase our costs. See Note 11 to the Notes to Consolidated Financial Statements for further discussion on workers' compensation.

Other Postretirement Benefits

Our sponsored health care plans provide retiree health benefits to eligible union and non-union retirees who have met certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits, and retiree contributions. These plans are not funded. We pay costs as incurred by participants. The estimated cost and benefits of the retiree health care plans are determined by independent actuaries, who, after review and approval by management, use various actuarial assumptions, including discount rate, expected trend in health care costs and per capita claims costs. At December 31, 2008 and December 31, 2007, the discount rate used to determine the other postretirement benefit liability was 6.10% and 6.50%, respectively. The impact of lowering the discount rate 0.25% for 2008 would have increased the 2008 net periodic postretirement benefit cost by approximately $0.3 million. At December 31, 2008, assumptions of our health care plans' cost trend were projected at annual rates of 8.5% for pre-Medicare claims, 8.8% for Medicare-eligible claims and 7.0% for Medicare supplemental plans, all ranging down to 5.0% by 2019 and remaining level thereafter. The impact of increasing the health care cost trend rate by 1.0% would have increased the 2008 net periodic postretirement benefit cost by approximately $3.2 million. Included in Note 10 to the Notes to Consolidated Financial Statements is a sensitivity analysis on the health care trend rate assumption.

Reclamation and Mine Closure Obligations

The SMCRA establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. Total reclamation and mine-closing liabilities are based upon permit requirements and engineering estimates related to these requirements. We account for our reclamation liabilities under SFAS 143. SFAS 143 requires that asset retirement obligations be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we considered the estimated current cost of reclamation and applied inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing. The estimated liability can change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

Contingencies

We are parties to a number of legal proceedings, incident to our normal business activities. These matters include contract disputes, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates, we do not believe that any liability arising from these matters individually or in the aggregate should have a material impact upon our consolidated cash flows, results of operations or financial condition. However, it is reasonably possible that the ultimate liabilities in the future with respect to these lawsuits and claims may be material to our cash flows, results of operations or financial condition. See Item 3. Legal Proceedings and Note 18 to the Notes to Consolidated Financial Statements for further discussion on our contingencies.

Income Taxes

We account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), as interpreted by FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48"), 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 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including tax attribute carrybacks, the future reversals of existing taxable temporary differences, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

Under FIN 48, we are required to establish reserves based upon management's assessment of exposure associated with tax positions taken relative to temporary and permanent tax differences and tax credits, plus penalties and interest, if any, on the accrued uncertain tax positions. The tax reserves are analyzed periodically and adjustments are made as events occur to warrant adjustment to the reserves. Management believes that we have adequately provided for any income taxes that may ultimately be paid with respect to all open tax years.

Coal Reserve Values

There are numerous uncertainties inherent in estimating quantities and values of economically recoverable coal reserves. Many of these uncertainties are beyond our control. As a result, estimates of economically recoverable coal reserves are by their nature uncertain. Information about our reserves consists of estimates based on engineering, economic and geological data assembled and analyzed by our internal engineers, geologists and financial associates. Some of the factors and assumptions that impact economically recoverable reserve estimates include: (i) geological conditions; (ii) historical production from similar areas with similar conditions; (iii) the assumed effects of regulations and taxes by governmental agencies; (iv) assumptions governing future prices; and (v) future operating costs.

Each of these factors may in fact vary considerably from the assumptions used in estimating reserves. For these reasons, estimates of the economically recoverable quantities of coal attributable to a particular group of properties, and classifications of these reserves based on risk of recovery and estimates of future net cash flows, may vary substantially. Actual production, revenue and expenditures with respect to reserves will likely vary from estimates, and these variances may be material. Variances would affect both the Consolidated Statements of Income, in the form of revenue and expenditures, as well as the Consolidated Balance Sheets, in the form of valuation of coal reserves, depletion rates and potential impairment.

Derivative Instruments

We evaluate each of our coal sales and coal purchase forward contracts under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities (as amended)" ("SFAS 133") to determine if they qualify for the normal purchase normal sale ("NPNS") exception prescribed by SFAS 133. The majority of our forward contracts do qualify for the NPNS exception based on management's intent and ability to physically deliver or take physical delivery of the coal. For those contracts that do not qualify for NPNS, the contracts are required to be accounted for as derivative instruments in accordance with SFAS 133, which requires all derivative instruments that do not qualify for teh NPNS exception to be recognized as assets or liabilities and to be measured at fair value. To establish fair values for these contracts, we use bid/ask price quotations obtained from independent third-party brokers. The net fair value change in our contracts deemed derivatives under SFAS 133 at December 31, 2008, was recognized as an unrealized loss in the current period earnings. We could experience difficulty in valuing our derivative instruments if the number of third-party brokers should decrease or market liquidity is reduced. See Note 15 to the Notes to Consolidated Financial Statements for further discussion of our derivative instruments.

Recent Accounting Pronouncements

Refer to Note 1 in the Notes to Consolidated Financial Statements for information concerning the effect of recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Discussions about Market Risk

Our net interest expense is currently not sensitive to changes in the general level of short-term interest rates. At December 31, 2008, all of the outstanding $1,465.6 million of our debt was under fixed-rate instruments. However, if it should become necessary to borrow under our asset-based revolving credit facility, those borrowings would be made at a variable rate. Interest income is sensitive to changes in short-term interest rates. Assuming that Cash and cash equivalents was fixed at the December 31, 2008 level of $607.0 million, a hypothetical 100 basis point decrease in money market interest rates would result in a decrease of approximately $6.1 million in Interest income.

In 2008, we primarily managed market price risk for coal through the use of long-term coal supply agreements, which are contracts with a term of one year or more in duration, rather than through the use of derivative instruments. We estimate that the percentage of tons sold pursuant to these long-term contracts was 97% for our fiscal year ended December 31, 2008. We anticipate that in 2009, the percentage of our tons sold pursuant to long-term contracts will be comparable with the percentage of our sales for 2008. The prices for coal shipped under long-term contracts may be below the current market price for similar types of coal at any given time. As a consequence of the substantial volume of our sales that are subject to these long-term agreements, we have less coal available with which to capitalize on stronger coal prices if and when they arise. In addition, because long-term contracts may allow the customer to elect volume flexibility based on requirements, our ability to realize the higher prices that may be available in the spot market may be restricted when customers elect to purchase higher volumes under such contracts, or our exposure to market-based pricing may be increased should customers elect to purchase fewer tons.

From time to time we may also purchase coal directly from third parties to supplement our produced and processed coal in order to provide coal to meet customer requirements under sales contracts. Certain of our purchase and sale contracts meet the definition of a derivative instrument under SFAS 133. The use of purchase and sales contracts which are accounted for as derivative instruments could materially affect our results of operations as a result of the requirement to mark them to market at the end of each reporting period in accordance with SFAS 133.

These transactions give rise to commodity price risk, which represents the potential gain or loss that can be caused by an adverse change in the price of coal. Outstanding purchase and sales contracts at December 31, 2008, that are accounted for as derivative instruments in accordance with SFAS 133 are summarized as follows:

	Price Range	Tons Outstanding	Delivery Period
Purchase Contracts	$49.00-$103.00	1,758,000	01/01/09-12/31/09
Sales Contracts	$48.00-$75.00	2,223,000	01/01/09-12/31/09

As of December 31, 2008, a hypothetical increase of 10% in the forward market price would result in an additional fair value loss recorded for these derivative instruments of $2.8 million. A hypothetical decrease of 10% in the forward market price would result in a reduction in the fair value loss recorded for these derivative instruments of $2.8 million.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited the accompanying consolidated balance sheets of Massey Energy Company as of December 31, 2008 and 2007, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule 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 Massey Energy Company 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. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 7 to the consolidated financial statements, in 2007 the Company changed its method for accounting for income taxes to comply with the accounting provisions of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*. As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for post-production stripping costs to comply with the accounting provisions of Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred During Production in the Mining Industry*. As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for defined benefit pension and other post-retirement plans to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statement Nos. 87, 77, 106, and 132(R)*. As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation to comply with the accounting provisions of Financial Accounting Standards Board Statement No. 123 (R), *Share-Based Payment*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Massey Energy 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 and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

Richmond, Virginia
February 27, 2009

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Amounts)

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
Revenues			
Produced coal revenue	$ 2,559,929	$ 2,054,413	$ 1,902,259
Freight and handling revenue	306,397	167,641	156,531
Purchased coal revenue	30,684	108,191	70,636
Other revenue	92,779	83,278	90,428
Total revenues	2,989,789	2,413,523	2,219,854
Costs and expenses			
Cost of produced coal revenue	1,910,953	1,641,774	1,599,092
Freight and handling costs	306,397	167,641	156,531
Cost of purchased coal revenue	28,517	95,241	62,613
Depreciation, depletion and amortization, applicable to:			
Cost of produced coal revenue	253,737	242,755	227,279
Selling, general and administrative	3,590	3,280	3,259
Selling, general and administrative	77,015	75,845	53,834
Other expense	3,207	7,308	6,240
Litigation charge	250,061	-	-
Loss on financing transactions	538	-	-
Net change in fair value of derivative instruments	22,552	-	-
Total costs and expenses	2,856,567	2,233,844	2,108,848
Income before interest and taxes	133,222	179,679	111,006
Interest income	23,576	23,969	20,094
Interest expense	(89,928)	(74,145)	(86,076)
Loss on short-term investment	(6,537)	-	-
Income before taxes	60,333	129,503	45,024
Income tax expense	(4,085)	(35,405)	(3,408)
Income before cumulative effect of accounting change	56,248	94,098	41,616
Cumulative effect of accounting change, net of tax	-	-	(639)
Net income	$ 56,248	$ 94,098	$ 40,977
Income per share - Basic			
Income before cumulative effect of accounting change	$ 0.69	$ 1.17	$ 0.51
Cumulative effect of accounting change	-	-	(0.01)
Net income	$ 0.69	$ 1.17	$ 0.50
Income per share - Diluted			
Income before cumulative effect of accounting change	$ 0.68	$ 1.17	$ 0.51
Cumulative effect of accounting change	-	-	(0.01)
Net income	$ 0.68	$ 1.17	$ 0.50
Shares used to calculate income per share			
Basic	81,816	80,123	80,847
Diluted	82,895	80,654	81,386

See Notes to Consolidated Financial Statements

MASSEY ENERGY COMPANY
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Amounts)

	December 31, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 606,997	$ 365,220
Short-term investment	39,383	-
Trade and other accounts receivable, less allowance of $873 and $444, respectively	233,266	156,572
Inventories	233,168	183,360
Income taxes receivable	6,621	16,302
Other current assets	116,061	165,940
Total current assets	1,235,496	887,394
Net Property, Plant and Equipment	2,297,696	1,793,920
Other Noncurrent Assets		
Pension assets	-	47,323
Other noncurrent assets	142,644	132,034
Total other noncurrent assets	142,644	179,357
Total assets	$ 3,675,836	$ 2,860,671
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable, principally trade and bank overdrafts	$ 244,201	$ 148,206
Short-term debt	1,976	1,875
Payroll and employee benefits	56,959	46,512
Other current liabilities	201,017	171,269
Total current liabilities	504,153	367,862
Noncurrent Liabilities		
Long-term debt	1,463,643	1,102,672
Deferred income taxes	117,268	154,705
Pension obligation	63,304	-
Other noncurrent liabilities	490,834	451,428
Total noncurrent liabilities	2,135,049	1,708,805
Total liabilities	2,639,202	2,076,667
Shareholders' Equity		
Capital stock		
Preferred – authorized 20,000,000 shares without par value; none issued	-	-
Common – authorized 150,000,000 shares of $0.625 par value; issued 85,447,970 and 82,818,578 shares, respectively	53,378	51,743
Treasury stock, 2,874,800 shares at cost	-	(79,986)
Additional capital	444,122	237,684
Retained earnings	640,496	601,587
Accumulated other comprehensive loss	(101,362)	(27,024)
Total shareholders' equity	1,036,634	784,004
Total liabilities and shareholders' equity	$ 3,675,836	$ 2,860,671

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF CASH FLOWS
(In Thousands)

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
Cash Flows from Operating Activities			
Net income	$ 56,248	$ 94,098	$ 40,977
Adjustments to reconcile Net income to Cash provided by operating activities:			
Cumulative effect of accounting change	-	-	639
Depreciation, depletion and amortization	257,327	246,035	230,538
Share-based compensation expense	13,856	17,095	7,350
Deferred income taxes	8,560	27,403	(17,381)
Gain on disposal of assets	(2,926)	(6,751)	(46,557)
Gain on reserve exchanges	(32,449)	(10,284)	-
Loss on financing transactions	7,049	-	-
Net change in fair value of derivative instruments	22,552	-	-
Unrealized loss on short-term investment	6,537	-	-
Accretion of asset retirement obligations	11,844	11,758	10,166
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(77,953)	19,253	(43,456)
(Increase) decrease in inventories	(49,808)	7,696	(8,070)
Decrease in other current assets	46,724	6,382	24,573
(Increase) decrease in other assets	(6,902)	(5,362)	9,920
Increase (decrease) in accounts payable and bank overdrafts	95,995	31,049	(45,632)
Increase (decrease) in accrued income taxes	10,048	(35,714)	42,638
Increase (decrease) in other accrued liabilities	21,189	(558)	17,046
Increase (decrease) in pension obligation	1,625	5,171	(8,755)
Increase (decrease) in other noncurrent liabilities	522	(212)	4,712
Asset retirement obligation payments	(4,957)	(11,061)	(4,205)
Cash provided by operating activities	385,081	395,998	214,503
Cash Flows from Investing Activities			
Capital expenditures	(736,529)	(270,461)	(298,132)
Redesignation of cash equivalent to short-term investment	(217,900)	-	-
Proceeds from redemption of short-term investment	171,980	-	-
Proceeds from sale of assets	5,958	28,118	51,467
Cash utilized by investing activities	(776,491)	(242,343)	(246,665)
Cash Flows from Financing Activities			
Issuance of common stock	258,188	-	-
Stock repurchase	-	(29,991)	(49,995)
Repayments of capital lease obligations	(1,911)	(2,409)	(10,214)
Proceeds from issuance of 3.25% convertible senior notes	674,136	-	-
Repurchase of 3.25% convertible senior notes	(10,450)	-	-
Tender payment for 6.625% senior notes	(322,139)	-	-
Proceeds from sale-leaseback transactions	41,318	13,146	21,819
Cash dividends paid	(21,310)	(12,837)	(12,814)
Proceeds from stock options exercised	16,519	4,001	2,142
Excess income tax (expense) benefit from stock option exercises	(1,164)	410	1,051
Cash provided (utilized) by financing activities	633,187	(27,680)	(48,011)
Increase (decrease) in cash and cash equivalents	241,777	125,975	(80,173)
Cash and cash equivalents at beginning of period	365,220	239,245	319,418
Cash and cash equivalents at end of period	$ 606,997	$ 365,220	$ 239,245
Supplemental Cash Flow Information			
Cash paid during the period for income taxes	$ 4,219	$ 34,052	$ 157

See Notes to Consolidated Financial Statements.

MASSEY ENERGY COMPANY
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(In Thousands, Except Per Share Amounts)

	Common Stock Shares	Common Stock Amount	Additional Capital	Unamortized Executive Stock Plan Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock	Total Shareholders' Equity
Balance at December 31, 2005	81,940	$ 51,213	$ 215,749	$ (7,130)	$ 581,621	$ (469)	$ -	$ 840,984
Net income					40,977			40,977
Other comprehensive income, net of deferred tax of $(21):								
Minimum pension liability adjustment						109		109
Comprehensive income								41,086
Adoption of accounting standards:								
Share-based payments			(7,130)	7,130				-
Post-production stripping costs, net of deferred tax of $59,970					(93,798)			(93,798)
Pension and postretirement plans,								-
net of deferred tax of $25,801						(40,356)		(40,356)
Dividends declared ($0.16 per share)					(12,906)			(12,906)
Stock option expense			6,112					6,112
Exercise of stock options	185	115	2,027					2,142
Stock option tax benefit			1,051					1,051
Restricted stock	239	129	2,822					2,951
Share repurchase	(1,299)						(49,995)	(49,995)
Issuance of stock for debt conversion	1	1	19					20
Balance at December 31, 2006	81,066	$ 51,458	$ 220,650	$ -	$ 515,894	$ (40,716)	$ (49,995)	$ 697,291
Net income					94,098			94,098
Other comprehensive income:								
Pension and postretirement plans, net of deferred tax of $8,754						13,692		13,692
Comprehensive income								107,790
Adoption of accounting standards:								
Uncertainty in income taxes					5,182			5,182
Dividends declared ($0.17 per share)					(13,587)			(13,587)
Stock option expense			8,308					8,308
Exercise of stock options	299	188	3,813					4,001
Stock option tax benefit			410					410
Restricted stock	155	97	4,503					4,600
Share repurchase	(1,576)						(29,991)	(29,991)
Balance at December 31, 2007	79,944	$ 51,743	$ 237,684	$ -	$ 601,587	$ (27,024)	$ (79,986)	$ 784,004
Net income					56,248			56,248
Other comprehensive income:								
Pension and								

postretirement plans, net of deferred tax of $47,528						(74,338)		(74,338)
Comprehensive loss								(18,090)
Dividends declared ($0.21 per share)					(17,339)			(17,339)
Stock option expense			8,204					8,204
Exercise of stock options	787	492	16,027					16,519
Stock option tax expense			(1,164)					(1,164)
Restricted stock	300	185	5,467					5,652
Issuance of stock for debt conversion	34	21	639					660
Issuance of additional common shares	4,370	937	177,265				79,986	258,188
Balance at December 31, 2008	85,435	$ 53,378	$ 444,122	$ -	$ 640,496	$ (101,362)	$ -	$ 1,036,634

See Notes to Consolidated Financial Statements.

1. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Massey Energy Company ("we", "our", or "us"), its wholly owned and sole, direct operating subsidiary A.T. Massey Coal Company, Inc. ("A.T. Massey") and A.T. Massey's wholly owned direct and indirect subsidiaries. Inter-company transactions and accounts are eliminated in consolidation. We have no independent assets or operations. We do not have a controlling interest in any separate independent operations. Investments in business entities in which we do not have control, but have the ability to exercise significant influence over the operating and financial policies, are accounted for under the equity method.

A.T. Massey fully and unconditionally guarantees our obligations under the 6.625% senior notes due 2010 ("6.625% Notes"), the 6.875% senior notes due 2013 ("6.875% Notes"), the 3.25% convertible senior notes due 2015 ("3.25% Notes"), the 4.75% convertible senior notes due 2023 ("4.75% Notes") and the 2.25% convertible senior notes due 2024 ("2.25% Notes"). In addition, the 6.625% Notes, the 6.875% Notes, the 3.25% Notes and the 2.25% Notes are fully and unconditionally, jointly and severally guaranteed by A.T. Massey and substantially all of our indirect operating subsidiaries, each such subsidiary being indirectly 100% owned by us. The subsidiaries not providing a guarantee of the 6.625% Notes, the 6.875% Notes, the 3.25% Notes and the 2.25% Notes are minor (as defined under Securities and Exchange Commission ("SEC") Rule 3-10(h)(6) of Regulation S-X). See Note 6 for a more complete discussion of debt.

Reclassifications

To maintain consistency and comparability, certain amounts from previously reported consolidated financial statements have been reclassified to conform to current year presentation. These reclassifications had no effect on previously reported consolidated operating income, net earnings or shareholders' equity.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect reported amounts. These estimates are based on information available as of the date of the financial statements. Therefore, actual results could differ from those estimates. The most significant estimates used in the preparation of the consolidated financial statements are related to defined benefit pension plans, coal workers' pneumoconiosis ("black lung"), workers' compensation, other postretirement benefits, reclamation and mine closure obligations, contingencies, income taxes, coal reserve estimates, stock options and derivative instruments.

Revenue Recognition

Produced coal revenue is realized and earned when title passes to the customer. Coal sales are made to our customers under the terms of coal supply agreements, most of which are long-term (one year or greater). Under the typical terms of these coal supply agreements, title and risk of loss transfer to the customer at the mine, dock, or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s) that serves each of our mines. We incur certain "add-on" taxes and fees on coal sales. Coal sales reported in Produced coal revenues include these "add-on" taxes and fees charged by various federal and state governmental bodies.

Freight and handling revenue consists of shipping and handling costs invoiced to coal customers and paid to third-party carriers. These revenues are directly offset by Freight and handling costs.

Purchased coal revenue represents revenue recognized from the sale of coal purchased from third-party production sources. We take title to the purchased coal, which we then resell to our customers. Typically, title and risk of loss transfer to the customer at the mine, dock or port, where coal is loaded to the rail, barge, ocean-going vessel, truck or other transportation source(s).

Other revenue includes refunds on railroad agreements, royalties related to coal lease agreements, gas well revenue, gains on the sale of non-strategic assets and reserve exchanges, joint venture revenue and other miscellaneous revenue. 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. Certain agreements require minimum lease payments regardless of the extent to which minerals are produced from the leasehold. The terms of these agreements generally range from specified periods of 5 to 10 years, or can be for an unspecified period until all reserves are depleted.

Derivative Instruments

We evaluate each of our coal sales and coal purchase forward contracts under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") to determine if they qualify for the normal purchase normal sale ("NPNS") exception prescribed by SFAS 133. The majority of our forward contracts do qualify for the NPNS exception based on management's intent and ability to physically deliver or take physical delivery of the coal. For those contracts that do not qualify for NPNS, the contracts are required to be accounted for as derivative instruments in accordance with SFAS 133, which requires all derivative instruments to be recognized as assets or liabilities and to be measured at fair value. Those contracts that have been identified as derivatives have not been designated as cash flow or fair value hedges and, accordingly, the net change in fair value is recorded in current period earnings. We record changes in derivative assets and liabilities subject to mark-to-market accounting on a net basis in Net change in fair value of derivative instruments in our Consolidated Statements of Income.

Cash and Cash Equivalents

Cash and cash equivalents are stated at cost, which approximates fair value. Cash equivalents are primarily invested in money market funds, which consist of highly liquid investments. At December 31, 2008, we maintained $607.0 million in Cash and cash equivalents. These balances include $305.0 million invested in shares of seven institutional money market funds, all of which carry AAA/Aaa ratings from Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), respectively. In addition, $265.0 million was invested in shares of institutional money funds which invest substantially all of their funds in securities supported by obligations of the United States Treasury and carry an AAA/Aaa rating from S&P and Moody's, respectively. All of these money funds participate in the U.S. Treasury Temporary Guarantee Program for Money Market Funds. The remaining $37.0 million is invested in other liquid interest and non-interest bearing accounts.

Short-Term Investment

Short-term investment is comprised of an investment in The Reserve Primary Fund ("Primary Fund"), a money market fund that has suspended redemptions and is being liquidated. We have determined that our investment in the Primary Fund no longer meets the definition of a security within the scope of Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities" ("SFAS 115") since the equity investment no longer has a readily determinable fair value. Therefore, the investment has been classified as a short-term investment subject to the cost method of accounting, and therefore reflected at the lower of cost or net realizable value. This classification as a short-term investment is based on our assessment of each of the individual securities that make up the underlying portfolio holdings in the Primary Fund, which primarily consisted of commercial paper and discount notes having maturity dates within the next 12 months, and the stated notifications from the Primary Fund that they expect to liquidate all of their holdings and make distributions within a year. Accordingly, we have reclassified our investment in the Primary Fund from Cash and cash equivalents to Short-term investment on our Consolidated Balance Sheet as of December 31, 2008. See Note 16 in the Notes to Consolidated Financial Statements for additional information.

Trade Receivables

Trade accounts receivable are recorded at the invoiced amount and are non-interest bearing. We maintain a bad debt reserve based upon the expected collectibility of our accounts receivable. The reserve includes specific amounts for accounts that are likely to be uncollectible, as determined by such variables as customer creditworthiness, the age of the receivables, bankruptcies and disputed amounts. Account balances are charged off against the reserve after all means of collection have been exhausted and the potential for recovery is considered remote.

Inventories

Produced coal and supplies inventories generally are stated at the lower of average cost or net realizable value. Coal inventory costs include labor, supplies, equipment, operating overhead and other related costs. Purchased coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value.

Prior to 2006, we accounted for the costs of removing overburden and waste materials (stripping costs) incurred during the production phase of a mine as a component of surface mining inventory costs. As overburden was removed, the stripping costs were captured in inventory costs and attributed to the proven reserves benefited. On January 1, 2006, we adopted Emerging Issues Task Force ("EITF") Issue No. 04-6, "Accounting for Stripping Costs Incurred During Production in the Mining Industry" ("EITF 04-6"). This consensus limits accounting for production-related stripping costs as a component of inventory to those costs associated with extracted or saleable inventories. Therefore, stripping costs in 2008, 2007 and 2006 are recorded as Cost of produced coal revenue while 2005 stripping costs were shown in Inventories as Advance stripping costs.

Surface mine stripping costs

We account for the costs of removing overburden and waste materials (stripping costs) at surface mines differently, depending upon whether the costs are incurred prior to producing coal (pre-production) versus after a more than de minimis amount of shippable product is produced (post-production). Production-related stripping costs are only included as a component of inventory if they are associated with extracted or saleable inventories. Pre-production stripping costs are capitalized in mine development and amortized over the life of the developed pit consistent with coal industry practices. Post-production stripping costs are expensed as incurred and recorded as Cost of produced coal revenue.

Pre-production stripping costs – 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 in mine development and amortized over the life of the developed pit consistent with coal industry practices.

Post-production stripping costs – 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.

Income Taxes

We account for income taxes in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 109, “Accounting for Income Taxes” (“SFAS 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 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion of the deferred tax asset will not be realized. In evaluating the need for a valuation allowance, we take into account various factors, including carrybacks, the expected level of future taxable income and available tax planning strategies. If actual results differ from the assumptions made in the evaluation of our valuation allowance, we record a change in valuation allowance through income tax expense in the period such determination is made.

In June 2006, the Financial Accounting Standards Board (“FASB”) issued Interpretation No. 48, “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109” (“FIN 48”) to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted FIN 48 effective January 1, 2007. We accrue interest and penalties, if any, related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense.

Property, Plant and Equipment

Property, plant and equipment are carried at cost and stated net of accumulated depreciation. Expenditures that extend the useful lives of existing buildings and equipment are capitalized. Maintenance and repairs are expensed as incurred. Coal exploration costs are expensed as incurred. 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. Development costs, including pre-production stripping costs, applicable to the opening of new coal mines and certain mine expansion projects are capitalized until production begins. When properties are retired or otherwise disposed, the related cost and accumulated depreciation are removed from the respective accounts and any profit or loss on disposition is credited or charged to Other revenue.

Our coal reserves are controlled either through direct ownership or through leasing arrangements. Mining properties owned in fee represent owned coal properties carried at cost. Leased mineral rights represent leased coal properties carried at the cost of acquiring those leases. The leases are generally long-term in nature (original term five to fifty years or until the mineable and merchantable coal reserves are exhausted), and substantially all of the leases contain provisions that allow for automatic extension of the lease term as long as mining continues.

Depreciation of buildings, plants and equipment is calculated on the straight-line method over their estimated useful lives or lease terms as follows:

	Years
Buildings and plants	20 to 30
Equipment	3 to 20
Capital leases	4 to 7

Ownership of assets under capital leases transfers to us at the end of the lease term. Depreciation of assets under capital leases is included within Depreciation, depletion and amortization.

Amortization of development costs is computed using the units-of-production method over the estimated proven and probable reserve tons.

Depletion of mining properties owned in fee and leased mineral rights is computed using the units-of-production method over the estimated proven and probable reserve tons (as adjusted for recoverability factors). As of December 31, 2008, approximately $152.2 million of costs associated with mining properties owned in fee and leased mineral rights are not currently subject to depletion as mining has not begun or production has been temporarily idled on the associated coal reserves.

We capitalize certain costs incurred in the development of internal-use software, including external direct material and service costs, in accordance with the American Institute of Certified Public Accountants' Statement of Position 98-1, "Accounting for the Costs of Computer Software Developed for or Obtained for Internal Use." All costs capitalized are amortized using the straight-line method over the estimated useful life not to exceed 7 years.

Impairment of Long-Lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value, which is usually measured based on an estimate of future discounted cash flows. There were no material impairment losses recorded during the periods covered by the consolidated financial statements.

Advance Mining Royalties

Coal leases that require minimum annual or advance payments and are recoverable from future production are generally deferred and charged to expense as the coal is subsequently produced. At December 31, 2008 and 2007, advance mining royalties included in Other noncurrent assets totaled $35.3 million and $37.0 million, net of an allowance of $14.7 million and $16.2 million, respectively.

Reclamation

We account for reclamation liabilities in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 requires that asset retirement obligations ("ARO") be recorded as a liability based on fair value, which is calculated as the present value of the estimated future cash flows, in the period in which it is incurred. Management and engineers periodically review the estimate of ultimate reclamation liability and the expected period in which reclamation work will be performed. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. When the liability is initially recorded, the offset is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Accretion expense is included in Cost of produced coal revenue. To settle the liability, the obligation is paid, and to the extent there is a difference between the liability and the amount of cash paid, a gain or loss upon settlement is incurred. Additionally, we perform a certain amount of required reclamation of disturbed acreage as an integral part of our normal mining process; these costs are expensed as incurred. See Note 9 for a more complete discussion of our reclamation liability.

Pension Plans

We sponsor a noncontributory defined benefit pension plan covering substantially all administrative and non-union employees. Our policy is to annually fund the defined benefit pension plan at or above the minimum amount required by law. We also sponsor a nonqualified supplemental benefit pension plan for certain salaried employees, which is unfunded.

We account for our defined benefit pension plans in accordance with SFAS No. 87 “Employers' Accounting for Pensions” (“SFAS 87”), which requires the costs of benefits to be provided to be accrued over the employees’ estimated remaining service life. These costs are determined on an actuarial basis. SFAS No. 158 “Employer’s Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)” (“SFAS 158”) amended SFAS 87, and requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost. We adopted SFAS 158 as of December 31, 2006. As a result of adoption, we recognized the funded status of the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan in the Consolidated Balance Sheet, decreasing the Pension asset by $53.2 million for the qualified defined benefit pension plan and increasing Other noncurrent liabilities by $199,000 for the nonqualified supplemental benefit pension plan. The $53.4 million, net of the deferred tax effect of $20.8 million, was recorded in Accumulated other comprehensive loss. See Note 5 for a more complete discussion of our pension plans.

Black Lung Benefits

We are responsible under the Federal Coal Mine Health and Safety Act of 1969, as amended, and under various states’ statutes for the payment of medical and disability benefits to employees and their dependents resulting from occurrences of black lung. We provide for federal and state black lung claims principally through a self-insurance program.

We account for our accumulated black lung obligations in accordance with SFAS No. 112 “Employers' Accounting for Postemployment Benefits—an amendment of FASB Statements No. 5 and 43” (“SFAS 112”), which requires the costs of benefits to be provided to be accrued over the employees’ estimated remaining service life. These costs are determined on an actuarial basis. SFAS No. 158 amended SFAS 112, and requires us to recognize the funded status of our black lung obligations in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. We use the service cost method to account for our self-insured black lung obligation. The liability measured under the service cost method represents the discounted future estimated cost for former employees either receiving or projected to receive benefits, and the portion of the projected liability relative to prior service for active employees projected to receive benefits. Expense for black lung under the service cost method represents the service cost, which is the portion of the present value of benefits allocated to the current year, interest on the accumulated benefit obligation, and amortization of unrecognized actuarial gains and losses. We amortize unrecognized actuarial gains and losses over a five-year period.

We adopted SFAS 158 as of December 31, 2006. As a result of adoption, we recognized the accumulated black lung obligation in the Consolidated Balance Sheet, decreasing the black lung liability by $16.6 million to $53.3 million ($50.3 million in Other noncurrent liabilities and $3.0 million in Other current liabilities at December 31, 2006). The $16.6 million decrease, net of the deferred tax of $6.5 million, was recorded in Accumulated other comprehensive loss. See Note 11 for a more complete discussion of black lung benefits.

Workers’ Compensation

We are liable for workers’ compensation benefits for traumatic injuries under state workers’ compensation laws in states in which we have operations. Our operations have workers’ compensation coverage through a combination of either a self-insurance program, or commercial insurance through a deductible or first dollar insurance policy. We record our self-insured liability on a discounted actuarial basis using various assumptions, including discount rate and future cost trends. See Note 11 for a more complete discussion of workers’ compensation benefits.

Postretirement Benefits Other than Pensions

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union members. Postretirement benefits other than pensions are accounted for in accordance with FAS No. 106 “Employers' Accounting for Postretirement Benefits Other Than Pensions” (“SFAS 106”), which requires the costs of benefits to be provided to be accrued over the employees’ estimated remaining service life. These costs are determined on an actuarial basis. SFAS 158 amended SFAS 106, and requires us to recognize the funded status of our benefit plans in our Consolidated Balance Sheet and to recognize as a component of Accumulated other comprehensive loss, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost. These amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost.

We adopted SFAS 158 as of December 31, 2006. As a result of adoption, we recognized the funded status of the postretirement medical benefit plans in the Consolidated Balance Sheet, increasing Other noncurrent liabilities by $29.4 million. The $29.4 million, net of the deferred tax effect of $11.5 million, was recorded in Accumulated other comprehensive loss.

Under the Coal Industry Retiree Health Benefits Act of 1992 (the “Coal Act”), coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the United Mine Workers of America (“UMWA”) Benefit Funds. We treat our obligation under the Coal Act as participation in a multi-employer plan as permitted by EITF No. 92-13, “Accounting for Estimated Payments in Connection with the Coal Industry Retiree Health Benefit Act of 1992,” and record the cost of our obligation as expense as payments are assessed. See Note 10 for a more complete discussion of postretirement benefits other than pensions.

Stock-based Compensation

Prior to 2006, we accounted for stock-based compensation using the intrinsic value method prescribed by Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees,” (“APB No. 25”) and related interpretations. On January 1, 2006, we adopted FASB Statement No. 123(R), “Share-Based Payments” (“SFAS 123R”) using the modified-prospective method. The modified-prospective method requires us to recognize compensation cost of equity instruments based on their grant-date fair value. Results from prior periods have not been restated. A cumulative effect of a change in accounting principle of $0.6 million loss (net of $0.4 million tax) was recognized in 2006 to reflect a change to the fair value method for those liability awards previously accounted for using the intrinsic value method and to reflect the impact of estimated forfeitures. We use the Black-Scholes option-pricing model to determine the fair value of stock options as of the date of grant and certain liability awards with option characteristics (i.e., stock appreciation rights, or “SARs”). For periods after the adoption date, compensation cost for both equity and liability awards have been measured and recorded in accordance with the provisions of SFAS 123R. The benefits of tax deductions in excess of recognized compensation cost are reported as a financing cash flow, rather than as an operating cash flow as required under previous literature. See Note 12 for a more complete discussion of stock-based compensation.

Earnings per Share

The number of shares used to calculate basic earnings per share is based on the weighted average number of our outstanding common shares during the respective periods. The number of shares used to calculate diluted earnings per share is based on the number of common shares used to calculate basic earnings per share plus the dilutive effect of stock options and other stock-based instruments held by our employees and directors during each period and debt securities currently convertible into our common stock, $0.625 par value (“Common Stock”) during the period. In accordance with accounting principles generally accepted in the United States, the effect of dilutive securities in the amount of 0.01 million, 0.8 million and 2.0 million for the years ended December 31, 2008, 2007 and 2006, respectively, was excluded from the calculation of the diluted earnings per common share as such inclusion would result in antidilution.

The computation for basic and diluted earnings per share is based on the following per share information:

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
	(In Thousands, Except Per Share Amounts)		
Numerator:			
Income before cumulative effect of accounting change - numerator for basic	$ 56,248	$ 94,098	$ 41,616
Cumulative effect of accounting change, net of tax	-	-	(639)
Effect of convertible notes	188	200	-
Net income - numerator for diluted	$ 56,436	$ 94,298	$ 40,977
Denominator:			
Weighted average shares - denominator for basic	81,816	80,123	80,847
Effect of stock options/restricted stock	772	207	539
Effect of convertible notes	307	324	-
Adjusted weighted average shares - denominator for diluted	82,895	80,654	81,386
Income per share:			
Basic:			
Before cumulative effect of accounting change	$ 0.69	$ 1.17	$ 0.51
Cumulative effect of accounting change	-	-	(0.01)
Net income	$ 0.69	$ 1.17	$ 0.50
Diluted:			
Before cumulative effect of accounting change	$ 0.68	$ 1.17	$ 0.51
Cumulative effect of accounting change	-	-	(0.01)
Net income	$ 0.68	$ 1.17	$ 0.50

Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157"). In February 2008, the FASB issued FASB Staff Position 157-2, Partial Deferral of the Effective Date of SFAS 157, which delayed the effective date of SFAS 157 for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities. We adopted SFAS 157 effective January 1, 2008 for financial assets and financial liabilities. The adoption of SFAS 157 for financial assets and liabilities did not have a material impact on our financial position or results of operations. We do not believe that the adoption of SFAS 157 for non-financial assets and non-financial liabilities will significantly impact our financial position and results of operations. See Note 16 to the Notes to Consolidated Financial Statements for more information on SFAS 157.

In October 2008, the FASB issued Staff Position No. FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" ("FSP 157-3"). FSP 157-3 clarifies the application of SFAS 157 for financial assets and liabilities in cases where a market is not active. We determined the guidance provided by FSP 157-3 in its estimation of fair values as of December 31, 2008 did not have an effect on our results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159, "Fair Value Option for Financial Assets and Liabilities – Including an amendment of FASB Statement No. 115" ("SFAS 159"). SFAS 159 permits entities to choose to measure certain financial assets and liabilities at fair value (the "fair value option"). Unrealized gains and losses, arising subsequent to the election of the fair value option, are reported in earnings. We adopted SFAS 159 effective January 1, 2008. We have not elected the fair value option for existing assets or liabilities upon adoption. Therefore, the implementation of SFAS 159 did not have an effect on our results of operations or financial position.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133" ("SFAS 161") which is effective for fiscal years beginning after November 15, 2008. SFAS 161 amends the disclosure requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" to provide an enhanced understanding of how and why derivative instruments are used, how they are accounted for and their effect on an entity's financial condition, performance and cash flows. We adopted SFAS 161 effective January 1, 2009, which will require additional disclosures to our Consolidated Financial Statements starting with our Form 10-Q filing for March 31, 2009.

In May 2008, the FASB issued FASB Staff Position APB 14-1 ("FSP APB 14-1"), "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)," which applies to all convertible debt instruments that have a ''net settlement feature,'' which means that such convertible debt instruments, by their terms, may be settled either wholly or partially in cash upon conversion. FSP APB 14-1 requires issuers of convertible debt instruments that may be settled wholly or partially in cash upon conversion to separately account for the liability and equity components in a manner reflective of the issuers' nonconvertible debt borrowing rate. FSP APB 14-1 requires that an entity determine the estimated fair value of a similar debt instrument as of the date of the issuance without the conversion feature but inclusive of any other embedded features and assign that value to the debt component of the instrument, which would result in a discount being recorded. The debt would subsequently be accreted through interest expense to its par value over its expected life using the market rate at the date of issuance. The residual value between the initial proceeds and the value allocated to the debt would be reflected in equity as additional paid in capital. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Early adoption is not permitted and retroactive application to all periods presented is required. FSP APB 14-1 is applicable to our 3.25% Notes. Due to the requirement to accrete the debt to its par value, which increases the debt component on which interest expense is computed, we expect to incur approximately $18 million of additional, non-cash interest charges in 2009, increasing to approximately $28 million in 2014.

2. Inventories

Inventories consisted of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Saleable coal	$ 144,834	$ 120,343
Raw coal	16,802	11,471
Subtotal coal inventory	161,636	131,814
Supplies inventory	71,532	51,546
Total inventory	$ 233,168	$ 183,360

Saleable coal represents coal ready for sale, including inventories designated for customer facilities under consignment arrangements of $50.7 million and $62.1 million at December 31, 2008 and 2007, respectively. Raw coal represents coal that generally requires further processing prior to shipment to the customer.

3. Other Current Assets

Other current assets are comprised of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Longwall panel costs	$ 12,290	$ 18,029
Deposits	59,648	109,200
Other	44,123	38,711
Total other current assets	$ 116,061	$ 165,940

Deposits consist primarily of funds placed in restricted accounts with financial institutions to collateralize letters of credit that support workers' compensation requirements, insurance and other obligations. Deposits at December 31, 2008 included $46.0 million of funds pledged as collateral to support $45.0 million of outstanding letters of credit. Deposits at December 31, 2007 included $96.0 million of funds pledged as collateral to support $45.1 million of outstanding letters of credit and a $50.0 million appeal bond which was used to pay Wheeling-Pittsburgh Steel Corporation ("Wheeling-Pittsburgh") during 2008 following the U.S. Supreme Court decision to not hear our appeal of the matter (see Note 18 to Notes to Consolidated Financial Statements for additional details). In addition, at December 31, 2008 and 2007 there were $13.0 million of United States Treasury securities supporting various regulatory obligations (see Note 6 for further discussion).

4. Property, Plant and Equipment

Property, plant and equipment is comprised of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Land, buildings and equipment	$ 2,538,762	$ 2,082,003
Mining properties owned in fee and leased mineral rights	779,932	704,547
Mine development	1,054,631	863,303
Total property, plant and equipment	4,373,325	3,649,853
Less accumulated depreciation, depletion and amortization	(2,075,629)	(1,855,933)
Net property, plant and equipment	$ 2,297,696	$ 1,793,920

Land, buildings and equipment includes gross assets under capital leases of $17.3 million at December 31, 2008 and 2007.

During 2008, we exchanged coal reserves and other assets with various third parties, recognizing a gain in Other revenue of $32.4 million (pre-tax) in accordance with Statement of Financial Accounting Standards ("SFAS") No 153, "Exchanges of Nonmonetary Assets, an Amendment of APB No. 29, Accounting for Nonmonetary Transactions." The acquired coal reserves and other assets were recorded in Property, plant and equipment at the fair value of the reserves and other assets surrendered.

During 2007, we exchanged coal reserves with a third-party, recognizing a gain in Other revenue of $10.3 million (pre-tax) in accordance with SFAS No 153. The gain included a $1.0 million cash payment. The acquired coal reserves were recorded in Property, plant and equipment at the fair value of the reserves surrendered, less the $1.0 million payment received.

During 2008 and 2007, we sold and leased-back certain mining equipment in several transactions for net proceeds of $41.3 million and $13.1 million, respectively. See Note 13 for further details.

5. Pension Plans

Defined Benefit Pension Plans

We sponsor a qualified non-contributory defined benefit pension plan, which covers substantially all administrative and non-union employees. Based on a participant's entrance date to the plan, the participant may accrue benefits based on one of four benefit formulas. Two of the formulas provide pension benefits based on the employee's years of service and average annual compensation during the highest five consecutive years of service. The third formula credits certain eligible employees with flat dollar contributions based on years of service with Massey and years of service under the UMWA 1974 Pension Plan. The fourth formula provides benefits under a cash balance formula with contribution credits based on hours worked. This last formula has a guaranteed rate of return on contributions of 4% for all contributions after December 31, 2003. Funding for the plan is generally at the minimum contribution level required by applicable regulations. We made voluntary contributions of $0.4 million to the qualified plan during 2007. No contributions were made during 2008.

An independent trustee holds the plan assets for the qualified defined benefit pension plan. The plan's assets include cash and cash equivalents, corporate and government bonds, preferred and common stocks and an investment in a group annuity contract. There were no investments in Common Stock held by the plan at December 31, 2008 or 2007. We have an internal investment committee ("Investment Committee") that sets investment policy, selects and monitors investment managers and monitors asset allocation. Diversification of assets is employed to reduce risk. The target asset allocation is 65%

for equity securities (including 50% domestic and 15% international) and 35% for cash and interest bearing securities. The investment policy is based on the assumption that the overall portfolio volatility will be similar to that of the target allocation. Given the volatility of the capital markets, strategic adjustments in various asset classes may be required to rebalance asset allocation back to its target policy. Investment fund managers are not permitted to invest in certain securities and transactions as outlined by the investment policy statements specific to each investment category without prior Investment Committee approval.

To develop the expected long-term rate of return on assets assumption, we considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio. This resulted in the selection of the 8.0% long-term rate of return on assets assumption for the year ended December 31, 2008.

The fair value of the major categories of qualified defined benefit pension plan assets includes the following:

	December 31, 2008		December 31, 2007	
	(Dollars In Thousands)			
Equity securities (domestic and international)	$ 112,638	54.2%	$ 187,439	64.2%
Debt securities	70,032	33.7%	72,417	24.8%
Other (includes cash, cash equivalents and a group annuity contract)	25,080	12.1%	31,891	11.0%
Total fair value of plan assets	$ 207,750	100.0%	$ 291,747	100.0%

In January 2009, the Investment Committee revised the target asset allocation for an interim period given the recent volatility and uncertainty in the equity securities markets. The targeted asset allocation for equity securities was set at 25% of current plan assets, with the balance of plan assets to be invested in cash, cash equivalents and debt securities. The plan asset portfolio has been rebalanced consistent with the revised targeted asset allocation strategy.

In addition to the qualified defined benefit pension plan noted above, we sponsor a nonqualified supplemental benefit pension plan for certain salaried employees. Participants in this nonqualified supplemental benefit pension plan accrue benefits under the same formula as the qualified defined benefit pension plan, however, where the benefit is capped by Internal Revenue Service (“IRS”) limitations, this nonqualified supplemental benefit pension plan compensates for benefits in excess of the IRS limit. This supplemental benefit pension plan is unfunded, with benefit payments made by us.

The following table sets forth the change in benefit obligation, plan assets and funded status of both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan:

	Year Ended	
	December 31, 2008	December 31, 2007
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 252,237	$ 256,925
Service cost	8,680	9,716
Interest cost	15,881	15,023
Actuarial loss (gain)	14,103	(18,796)
Benefits paid	(10,773)	(10,631)
Benefit obligation at the end of the period	280,128	252,237
Change in plan assets:		
Fair value at the beginning of the period	291,747	285,419
Actual (loss) return on assets	(73,286)	16,512
Company contributions	62	447
Benefits paid	(10,773)	(10,631)
Fair value of plan assets at end of period	207,750	291,747
Funded status	$ (72,378)	$ 39,510
Qualified defined benefit pension plan, included in Pension (obligation) assets	$ (63,304)	$ 47,323
Nonqualified supplemental benefit pension plan, included in Other noncurrent liabilities	(9,074)	(7,813)
Accrued pension (obligation) assets recognized, net	$ (72,378)	$ 39,510

The nonqualified supplemental benefit pension plan had an accumulated benefit obligation of $8.6 million and $7.2 million as of December 31, 2008 and 2007, respectively.

The table below details the changes to Accumulated other comprehensive loss related to defined benefit pension plans in accordance with SFAS 158:

	2008		2007	
	(In Thousands)			
	Net loss	Prior service cost	Net loss	Prior service cost
January 1 beginning balance	22,482	60	32,821	84
Changes to Accumulated other comprehensive loss	66,778	(26)	(10,339)	(24)
December 31 ending balance	$ 89,260	$ 34	$ 22,482	$ 60

We expect the estimated net loss and prior service cost for the defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year to be $17.0 million and $41,000, respectively.

The assumptions used in determining pension benefit obligations for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2008	December 31, 2007
Discount rates	6.10%	6.50%
Rates of increase in compensation levels	4.00%	4.00%

Net periodic pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan includes the following components:

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
		(In Thousands)	
Service cost	$ 8,680	$ 9,716	$ 9,230
Interest cost	15,881	15,023	13,922
Expected return on plan assets	(22,852)	(22,427)	(19,952)
Recognized loss	770	4,068	6,226
Amortization of prior service cost	42	39	39
Net periodic pension expense	$ 2,521	$ 6,419	$ 9,465

The assumptions used in determining pension expense for both the qualified defined benefit pension plan and nonqualified supplemental benefit pension plan are as follows:

	December 31, 2008	December 31, 2007	December 31, 2006
Discount rates	6.50%	5.90%	5.75%
Rates of increase in compensation levels	4.00%	4.00%	4.00%
Expected long-term rate of return on plan assets	8.00%	8.00%	8.00%

We expect that contributions will be required in 2009 for the qualified defined benefit pension plan, estimated to be $10 million. We expect to voluntarily contribute approximately $300,000 for benefit payments to participants in 2009 for the nonqualified supplemental benefit pension plan.

The following benefit payments from both the qualified defined benefit pension plan and the nonqualified supplemental benefit pension plan, which reflect expected future service, as appropriate, are expected to be paid from the plans:

	Benefit Payments
	(In Thousands)
2009	$ 12,421
2010	12,960
2011	13,514
2012	14,360
2013	15,069
Years 2014 to 2018	90,027

Multi-Employer Pension

Under labor contracts with the UMWA, certain operations make payments into two multi-employer defined benefit pension plan trusts established for the benefit of certain union employees. The contributions are based on tons of coal produced and hours worked. Such payments aggregated less than $600,000 in the year ended December 31, 2008, less than $400,000 in the year ended December 31, 2007 and less than $100,000 in the year ended December 31, 2006.

Defined Contribution Plan

We currently sponsor a defined contribution pension plan for certain union employees. The plan is non-contributory and our contributions are based on hours worked. Contributions to this plan were approximately $50,000 for the years ended December 31, 2008 and 2007, and $100,000 for the year ended December 31, 2006.

Salary Deferral and Profit Sharing (401(K)) Plan

We also sponsor a salary deferral and profit sharing plan covering substantially all administrative and non-union employees. The maximum salary deferral rate is 75% of eligible pay, subject to IRS limitations. We contribute a fixed match on employee contributions on up to 10% of eligible pay. Our contributions aggregated approximately $4.6 million, $3.6 million and $3.9 million for the years ended December 31, 2008, 2007 and 2006, respectively.

6. Debt

Our debt is comprised of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
6.875% senior notes due 2013, net of discount	$ 756,041	$ 755,401
3.25% convertible senior notes due 2015	671,000	-
6.625% senior notes due 2010	21,949	335,000
2.25% convertible senior notes due 2024	9,647	9,647
4.75% convertible senior notes due 2023	70	730
Capital lease obligations	6,912	8,823
Fair value hedge adjustment	-	(5,054)
Total debt	1,465,619	1,104,547
Amounts due within one year	(1,976)	(1,875)
Total long-term debt	$ 1,463,643	$ 1,102,672

The weighted average effective interest rate of the outstanding borrowings was 5.2% and 7.0% at December 31, 2008 and 2007, respectively, after giving effect to the amortization of the Fair value hedge adjustment.

Financing Transactions

On August 5, 2008, we commenced a consent solicitation and tender offer for any and all of the outstanding $335 million of 6.625% Notes and concurrently we commenced registered underwritten public offerings of convertible senior notes (the 3.25% Notes) and shares of Common Stock and announced our intention to use the proceeds of the offerings to purchase some or all of the 6.625% Notes in the tender offer and for general corporate purposes.

On August 19, 2008, we settled with holders of $311.5 million of the 6.625% Notes, representing approximately 93% of the outstanding 6.625% Notes, who tendered their 6.625% Notes pursuant to our consent solicitation and tender offer for the 6.625% Notes. The total consideration for these 6.625% Notes was $1,026.57 per $1,000 principal amount of the 6.625% Notes. The total consideration included a consent payment of $25 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

As a result of the consents of approximately 93% of the outstanding 6.625% Notes, we received the requisite consents to execute a supplemental indenture relating to the 6.625% Notes, which eliminated substantially all of the restrictive covenants in the 6.625% Notes' indenture.

On September 3, 2008, we settled with holders of an additional $1.6 million of the 6.625% Notes, who tendered their 6.625% Notes after the consent solicitation deadline. The total consideration for these 6.625% Notes was $1,001.57 per $1,000 principal amount of the 6.625% Notes. In addition to the total consideration, holders also received interest which was accrued and unpaid since the previous interest payment date.

We recognized charges totaling $15.2 million, including $1.9 million for the write-off of unamortized financing fees and $4.2 million for the unamortized interest rate swap termination payment (as discussed below) recorded in Interest expense, and $9.1 million for the debt consent solicitation and tender offer recorded in Loss on financing transactions.

6.875% Notes

The 6.875% Notes are unsecured obligations ranking equally with all other unsecured senior indebtedness of ours and are guaranteed by substantially all of our current and future subsidiaries, (the "Guarantors"). Interest on the 6.875% Notes is payable on December 15 and June 15 of each year. We may redeem the 6.875% Notes, in whole or in part, for cash at any time on or after December 15, 2009 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.875% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

The 6.875% Notes contain a number of significant restrictions and covenants that limit our ability and our subsidiaries' ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) restrict distributions from subsidiaries. We are currently in compliance with all covenants.

3.25% Notes

On August 12, 2008, we issued $690 million of 3.25% convertible senior notes due 2015 in a registered underwritten public offering, resulting in net proceeds to us of approximately $674.1 million. The 3.25% Notes are guaranteed on a senior unsecured basis by the Guarantors. The subsidiaries not providing a guarantee of the 3.25% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X). The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The 3.25% Notes and the guarantees rank equally with all of our and the Guarantors' existing and future senior unsecured indebtedness and rank senior to all of our and the Guarantors' indebtedness that is expressly subordinated to the 3.25% Notes and the guarantees, but are effectively subordinated to all of our and the Guarantors' existing and future senior secured indebtedness to the extent of the value of the assets securing the indebtedness and to all liabilities of our subsidiaries that are not Guarantors.

The 3.25% Notes bear interest at a rate of 3.25% per annum, payable semi-annually in arrears on August 1 and February 1 of each year, beginning on February 1, 2009. The 3.25% Notes will mature on August 1, 2015, unless earlier repurchased by us or converted.

The 3.25% Notes are convertible in certain circumstances during certain periods at an initial conversion rate of 11.4106 shares of Common Stock per $1,000 principal amount of 3.25% Notes (which represented an initial conversion price of approximately $87.64 per share), subject to adjustment in certain circumstances.

The 3.25% Notes are convertible under certain circumstances and during certain periods into (i) cash, up to the aggregate principal amount of the 3.25% Notes subject to conversion and (ii) cash, shares of Common Stock or a combination thereof, at our election in respect to the remainder (if any) of our conversion obligation. Subject to earlier repurchase, the 3.25% Notes will be convertible only in the following circumstances and to the following extent:

- during any calendar quarter, if the closing sale price of our shares of Common Stock for each of 20 or more trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter exceeds 130% of the conversion price in effect on the last trading day of the immediately preceding calendar quarter;

- during the five consecutive business days immediately after any five consecutive trading day period (the "note measurement period") in which the average trading price per $1,000 principal amount of 3.25% Notes was equal to or less than 97% of the average conversion value of the 3.25% Notes during the note measurement period;

- if we make certain distributions on our shares of Common Stock or engage in certain transactions; and

- at any time from, and including, February 1, 2015 until the close of business on the second business day immediately preceding August 1, 2015.

None of the 3.25% Notes are currently eligible for conversion.

The indenture governing the 3.25% Notes contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the trustee for the 3.25% Notes or the holders of not less than 25% in aggregate principal amount of the 3.25% Notes then outstanding may declare the unpaid principal of the 3.25% Notes and any accrued and unpaid interest thereon immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us, the principal amount of the 3.25% Notes together with any accrued and unpaid interest thereon will automatically become and be immediately due and payable.

Open Market Debt Repurchase

On November 6, 2008, we concluded an open market purchase, retiring $19.0 million of principal amount of the 3.25% Notes at a cost of $10.4 million, plus accrued interest resulting in a gain of $8.6 million recorded in Loss on financing transactions.

6.625% Notes

The 6.625% senior notes due 2010 are unsecured obligations of ours and rank equally with all other unsecured senior indebtedness. Interest is payable semiannually on May 15 and November 15 of each year. We may redeem the 6.625% Notes, in whole or in part, at any time on or after November 15, 2007 at a redemption price equal to 100% of the principal amount plus a premium declining ratably to par, plus accrued and unpaid interest. The 6.625% Notes are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 6.625% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X).

2.25% Notes

The 2.25% convertible senior notes due 2024 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by the Guarantors. The guarantees are full and unconditional obligations of the Guarantors and are joint and several among the Guarantors. The subsidiaries not providing a guarantee of the 2.25% Notes are minor (as defined under SEC Rule 3-10(h)(6) of Regulation S-X). Interest is payable semiannually on April 1 and October 1 of each year. We registered the 2.25% Notes with the SEC for resale.

Holders of the 2.25% Notes may require us to purchase all or a portion of their notes for cash on April 1, 2011, 2014, and 2019, at a purchase price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest. In addition, if we experience certain specified types of fundamental changes on or before April 1, 2011, the holders may require us to purchase the notes for cash. We may redeem all or a portion of the 2.25% Notes for cash at any time on or after April 6, 2011, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 2.25% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 29.7619 shares of Common Stock per $1,000 principal amount of 2.25% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 2.25% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 2.25% Notes decline below certain specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $33.60 per share. None of the 2.25% Notes are currently eligible for conversion. As of December 31, 2008, if all of the notes outstanding were eligible and were converted, we would have needed to issue 287,113 shares of Common Stock.

4.75% Notes

The 4.75% convertible senior notes due 2023 are unsecured obligations of ours, rank equally with all other unsecured senior indebtedness and are guaranteed by our wholly owned subsidiary, A.T. Massey, which together with our subsidiaries accounts for substantially all of our assets and all of our revenues. Interest is payable semiannually on May 15 and November 15 of each year. We registered the 4.75% Notes with the SEC for resale.

We may be required by the holders of the 4.75% Notes to purchase all or a portion of their notes on May 15, 2009, 2013, and 2018. For purchases on May 15, 2009, we must pay cash for all 4.75% Notes so purchased. For purchases on May 15, 2013 or 2018, we may, at our option, choose to pay the purchase price for such 4.75% Notes in cash, in shares of Common Stock or any combination thereof. We may redeem some or all of the 4.75% Notes at any time on or after May 20, 2009, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus any accrued and unpaid interest.

The 4.75% Notes are convertible during certain periods by holders into shares of Common Stock initially at a conversion rate of 51.573 shares of Common Stock per $1,000 principal amount of 4.75% Notes (subject to adjustment upon certain events) under the following circumstances: (i) if the price of Common Stock issuable upon conversion reaches specified thresholds; (ii) if we redeem the 4.75% Notes; (iii) upon the occurrence of certain specified corporate transactions; or (iv) if the credit ratings assigned to the 4.75% Notes decline below specified levels. Regarding the thresholds in (i) above, holders may convert each of their notes into shares of Common Stock during any calendar quarter (and only during such calendar quarter) if the last reported sale price of Common Stock for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter is greater than or equal to 120% of the conversion price per share of Common Stock. The conversion price is $19.39 per share.

As of December 31, 2008, the price of Common Stock had not reached the specified threshold for conversion. As of December 31, 2008, if all of the notes outstanding were eligible and were converted, we would have needed to issue 3,610 shares of Common Stock.

In June 2008, $660,000 of principal amount of the 4.75% Notes was converted into 34,037 shares of Common Stock. No other conversions occurred during the year.

Fair Value Hedge Adjustment

On December 9, 2005, we exercised our right to terminate our interest rate swap agreement, which was designated as a hedge against a portion of the 6.625% Notes. We paid a $7.9 million termination payment to the swap counterparty on December 13, 2005. The termination payment, which is reflected in the table above at December 31, 2007, as Fair value hedge adjustment, was being amortized into Interest expense through November 15, 2010, the maturity date of the 6.625% Notes. As discussed in this Note under Financing Transactions above, on August 19, 2008, we settled with holders of approximately 93% of the outstanding 6.625% Notes that were tendered pursuant to our consent solicitation and tender offer for the 6.625% Notes. As a result of the acceptance of the consent solicitation and tender offer of the 6.625% Notes, the remaining balance of the Fair value hedge adjustment of $4.2 million was written off to Interest expense. For the twelve months ended December 31, 2008, $5.1 million of the Fair value hedge adjustment was recorded in Interest expense.

Asset-Based Lending Arrangement

On August 15, 2006, we entered into an amended and restated asset-based revolving credit facility, which provides for available borrowings, including letters of credit of up to $175 million, depending on the level of eligible inventory and accounts receivables. As of December 31, 2008, this facility supported $75.5 million of letters of credit and there were no outstanding borrowings under this facility. Any future borrowings under this facility will be variable rate borrowings, based on the applicable LIBOR rate for the specified rate reset period, plus an applicable margin. As of December 31, 2008, the applicable margin to LIBOR was 125 basis points.

The facility is secured by our accounts receivable, eligible coal inventories located at our facilities and on consignment at customers' facilities, and other intangibles. At December 31, 2008, total remaining availability was $99.5 million based on qualifying inventory and accounts receivable. The credit facility expires on May 15, 2010; however if the 6.625% Notes have been refinanced, defeased, or paid in full by May 15, 2010, the expiration date is extended to August 15, 2011.

This facility contains a number of significant restrictions and covenants that limit our ability to, among other things: (i) incur liens and debt or provide guarantees in respect of obligations of any other person; (ii) increase Common Stock dividends above specified levels; (iii) make loans and investments; (iv) prepay, redeem or repurchase debt; (v) engage in mergers, consolidations and asset dispositions; (vi) engage in affiliate transactions; (vii) create any lien or security interest in any real property or equipment; (viii) engage in sale and leaseback transactions; and (ix) make distributions from subsidiaries. This facility also contains financial covenants, which become operative only when our Average Excess Availability (as defined in the facility documents) is less than $30 million. These financial covenants include a Minimum Consolidated Fixed Charge Ratio of 1.00 to 1.00 and a minimum Consolidated Net Worth of $550 million under the terms of the ABL Facility (currently approximately $400 million as adjusted for Accounting Changes). We are currently in compliance with all covenants.

Debt Maturity

The aggregate amounts of scheduled long-term debt maturities assuming convertible notes are not eligible for conversion, including capital lease obligations, subsequent to December 31, 2008 are as follows:

	(In Thousands)
2009	$ 1,976
2010	24,167
2011	2,670
2012	13
2013	760,012
Beyond 2013*	680,740

* The 4.75% Notes and the 2.25% Notes in the amounts of $0.1 million and $9.6 million, respectively, included herein may be redeemed at the option of the holders in 2009 and 2011, respectively.

Total interest paid for the years ended December 31, 2008, 2007 and 2006, was $114.2 million, $75.7 million and $75.0 million, respectively.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements including guarantees, operating leases, indemnifications, and financial instruments with off-balance sheet risk, such as bank letters of credit and performance or surety bonds. Liabilities related to these arrangements are not reflected in the consolidated balance sheets, and, except for the operating leases, which are discussed in Note 13 to the Notes to Consolidated Financial Statements, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

From time to time we use bank letters of credit to secure our obligations for worker's compensation programs, various insurance contracts and other obligations. At December 31, 2008, we had $120.5 million of letters of credit outstanding of which $45.0 million was collateralized by $46.0 million of cash deposited in restricted, interest bearing accounts pledged to issuing banks and $75.5 million was issued under our asset based lending arrangement. No claims were outstanding against those letters of credit as of December 31, 2008.

On January 22, 2008, a settlement was reached regarding our previously reported disagreement and protest of a new actuarial methodology being applied by the Office of Workers' Claims ("OWC") for the Commonwealth of Kentucky in determining levels of surety against potential future claims. The settlement resulted in the dismissal of our cases pending in the Franklin County Circuit Court of Kentucky and required us to post additional surety of $11.5 million for the 2006 and 2007 assessments against potential claims. That additional surety requirement was satisfied with the posting of a letter of credit issued under our asset-based lending arrangement.

We use surety bonds to secure reclamation, workers' compensation, wage payments, and other miscellaneous obligations. As of December 31, 2008, we had $330.2 million of outstanding surety bonds. These bonds were in place to secure obligations as follows: post-mining reclamation bonds of $321.1 million and other miscellaneous obligation bonds of $9.1 million. Outstanding surety bonds of $46.1 million are secured with letters of credit. In addition, in December 2008, a $50.0 million appeal bond in the Wheeling-Pittsburgh legal matter was used to pay the plaintiff following the U.S. Supreme Court decision to not hear our appeal of the matter (see Note 18 to Notes to Consolidated Financial Statements for additional details).

Generally, the availability and market terms of surety bonds continue to be challenging. If we are unable to meet certain financial tests applicable to some of our surety bonds, or to the extent that surety bonds otherwise become unavailable, we would need to replace the surety bonds or seek to secure them with letters of credit, cash deposits, or other suitable forms of collateral.

7. Income Taxes

Income tax expense included in the Consolidated Statements of Income is as follows:

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
		(In Thousands)	
Current:			
Federal	$ (4,597)	$ 7,876	$ 20,694
State and local	122	126	95
Total current	(4,475)	8,002	20,789
Deferred:			
Federal	7,274	24,593	(15,439)
State and local	1,286	2,810	(1,942)
Total deferred	8,560	27,403	(17,381)
Income tax expense	$ 4,085	$ 35,405	$ 3,408

A reconciliation of Income tax expense calculated at the federal statutory rate of 35% to our Income tax expense on Net income is as follows:

	Year Ended		
	December 31, 2008	December 31, 2007	December 31, 2006
		(In Thousands)	
U.S. statutory federal tax expense	$ 21,117	$ 45,326	$ 15,758
Increase (Decrease) resulting from:			
State taxes	66	(116)	(2,393)
Non-deductible penalties	6,240	8,062	852
Percentage depletion	(45,671)	(33,501)	(25,897)
Non-deductible compensation	666	711	1,279
Non-deductible refinancing and exchange offer costs	-	(4,809)	-
Extraterritorial excluded income	-	-	(797)
Valuation allowance adjustment	28,098	31,343	16,066
Uncertain tax positions	-	(2,325)	(1,197)
Alternative minimum tax credit refund, net of adjustment	(4,770)	-	-
Refund from settlement of 2001 IRS audit	-	(4,609)	-
Other, net	(1,661)	(4,677)	(263)
Income tax expense	$ 4,085	$ 35,405	$ 3,408

Deferred taxes reflect the tax effects of differences between the amounts recorded as assets and liabilities for financial reporting purposes and the amounts recorded for income tax purposes. The tax effects of temporary differences giving rise to deferred tax assets and liabilities are as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In Thousands)	
Deferred tax assets:		
Postretirement benefit obligations	$ 117,106	$ 66,235
Workers' compensation	24,682	22,588
Reclamation and mine closure	46,608	47,281
Alternative minimum tax credit carryforwards	104,782	119,651
Litigation	9,777	10,247
Deferred compensation	26,088	24,308
Federal net operating loss	115,897	98,434
State net operating loss	25,083	28,194
Other	35,718	27,835
Total deferred tax assets	505,741	444,773
Valuation allowance for deferred tax assets	(202,318)	(194,122)
Total deferred tax assets, net of valuation allowance	303,423	250,651
Deferred tax liabilities:		
Plant, equipment and mine development	(273,878)	(275,362)
Mining property and mineral rights	(131,308)	(117,609)
Deferred royalties	(9,863)	(10,339)
Other	(5,642)	(2,046)
Total deferred tax liablities	(420,691)	(405,356)
Deferred income taxes	$ (117,268)	$ (154,705)

Deferred tax assets include alternative minimum tax ("AMT") credits of $104.8 million and $119.7 million at December 31, 2008 and 2007, respectively, federal net operating loss carryforwards of $331.1 million and $281.2 million as of December 31, 2008 and 2007, respectively, and net state net operating loss ("NOL") carryforwards of $627.1 million and $704.8 million as of December 31, 2008 and 2007, respectively. The AMT credits have no expiration date. Federal NOL carryforwards expire beginning in 2018 and ending in 2023. State NOL carryforwards expire beginning in 2008 and ending in 2023. The NOL carryforwards available at December 31, 2008 increased over the amount available at the end of the prior year primarily due to 2008 taxable losses.

We have recorded a valuation allowance for a portion of deferred tax assets that management believes, more likely than not, will not be realized. These deferred tax assets include AMT credits, federal NOL and state NOL carryforwards that will likely not be realized at the maximum effective tax rate. The valuation allowance increased for the year ended December 31, 2008 primarily as a result of the increase in federal NOL carryforwards discussed above.

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") to create a single model to address accounting for uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. We increased Retained earnings by $5.2 million for the cumulative effect of adoption of FIN 48 as of January 1, 2007. We accrue interest and penalties, if any, related to unrecognized tax benefits in Other noncurrent liabilities and recognize the related expense in Income tax expense. We accrued $0.8 million and $3.1 million in interest related to unrecognized tax benefits for the years December 31, 2008 and 2007, respectively.

The following table reconciles the total amount of unrecognized tax benefits, including those identified in 2007 related to the disallowed ten-year carryback claims:

	2008	2007
	(In Thousands)	
Balance at January 1	$ -	$ 2,325
Additions based on tax positions related to the current year	-	-
Additions for tax positions of prior years	-	49,130
Reductions for tax positions of prior years	-	(2,325)
Settlements	-	(49,130)
Reductions due to lapse of applicable statute of limitations	-	-
Balance at December 31	$ -	$ -

Prior to the adoption of FIN 48, we followed a methodology of establishing reserves for tax contingencies when, despite the belief that our tax return positions were fully supported, certain positions were likely to be challenged and might not be fully sustained. We establish the reserves based upon management's assessment of exposure associated with permanent tax differences (i.e., tax depletion expense), tax credits and interest expense applied to temporary difference adjustments. The tax reserves were analyzed at least annually and adjustments were made based upon changes in facts and circumstances, such as the progress of federal and state audits, case law and emerging legislation. During 2006, we reduced our tax reserve by $1.2 million, reflecting the reduction in exposure due to the notification of no exceptions from the IRS of a prior statutory period, partially offset by additional exposures identified for that tax year. Payments for federal taxes and state taxes of $63,000 were applied against the reserve during the year ended December 31, 2006, as a result of audits of prior periods.

We file income tax returns in the United States federal and various state jurisdictions, including West Virginia, Kentucky and Virginia. The Internal Revenue Service ("IRS") has examined our federal income tax returns, or statutes of limitations have expired for years through 2004. In the various states where we file state income tax returns, the state tax authorities have examined our state returns, or statutes of limitations have expired through 2004. Management believes that we have adequately provided for any income taxes that may ultimately be paid with respect to all open tax years. All unrecognized tax benefits would affect the effective tax rate if we were to recognize them.

8. Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Reclamation (Note 9)	$ 154,823	$ 142,213
Other postretirement benefits (Note 10)	161,527	141,087
Workers' compensation and black lung (Note 11)	92,982	90,702
Other	81,502	77,426
Total other noncurrent liabilities	$ 490,834	$ 451,428

9. Reclamation

Our reclamation liabilities primarily consist of spending estimates related to reclaiming surface land and support facilities at both surface and underground mines in accordance with federal and state reclamation laws as defined by each mine permit. The obligation and corresponding asset are recognized in the period in which the liability is incurred.

We estimate our ultimate reclamation liability based upon detailed engineering calculations of the amount and timing of the future cash flows to perform the required work. We consider the estimated current cost of reclamation and apply inflation rates and a third-party profit, as necessary. The third-party profit is an estimate of the approximate markup that would be charged by contractors for work performed on our behalf. The discount rate applied is based on the rates of treasury bonds with maturities similar to the estimated future cash flow, adjusted for our credit standing.

The following table describes all changes to our reclamation liability:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In Thousands)	
Reclamation liability at beginning of period	$ 168,641	$ 171,954
Accretion expense	11,844	11,758
Liability assumed/incurred	16,956	2,168
Liability disposed	(212)	(142)
Revisions in estimated cash flows	(6,092)	(6,036)
Payments	(4,957)	(11,061)
Reclamation liability at end of period	186,180	168,641
Less amount included in Other current liabilities	31,357	26,428
Total reclamation, included in Other noncurrent liabilities	$ 154,823	$ 142,213

10. Other Postretirement Benefits

We sponsor defined benefit health care plans that provide postretirement medical benefits to eligible union and non-union employees. To be eligible, retirees must meet certain age and service requirements. Depending on year of retirement, benefits may be subject to annual deductibles, coinsurance requirements, lifetime limits and retiree contributions. Service costs are accrued currently based on an annual study prepared by independent actuaries. These plans are unfunded.

Net periodic postretirement benefit cost includes the following components:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
		(In Thousands)	
Service cost	$ 3,204	$ 3,668	$ 3,758
Interest cost	8,845	8,467	7,959
Amortization of net loss	813	1,864	2,307
Amortization of prior service credit	(750)	(750)	(750)
Net periodic postretirement benefit cost	$ 12,112	$ 13,249	$ 13,274

The discount rate assumed to determine the net periodic postretirement benefit cost was 6.50%, 5.90% and 5.75% for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table sets forth the change in benefit obligation of our postretirement benefit plans:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In Thousands)	
Change in benefit obligation:		
Benefit obligation at the beginning of the period	$ 147,733	$ 144,325
Service cost	3,204	3,668
Interest cost	8,845	8,467
Actuarial loss/(gain)	15,538	(3,546)
Benefits paid	(6,691)	(5,181)
Benefit obligation at the end of the period	$ 168,629	$ 147,733
Accrued postretirement benefit obligation	$ 168,629	$ 147,733
Amount included in Payroll and employee benefits	7,102	6,646
Postretirement benefit obligation, included in Other noncurrent liabilities	$ 161,527	$ 141,087

The table below details the changes to Accumulated other comprehensive loss related to defined benefit pension plans in accordance with SFAS 158:

	Year Ended			
	2008		2007	
	(In Thousands)			
	Net loss	Prior service credit	Net loss	Prior service credit
January 1 beginning balance	$ 20,132	$ (5,063)	$ 23,434	$ (5,521)
Changes to Accumulated other comprehensive loss	8,979	458	(3,302)	458
December 31 ending balance	$ 29,111	$ (4,605)	$ 20,132	$ (5,063)

We expect to recognize $0.8 million of prior service credit and $2.4 million of net actuarial loss in 2009.

The discount rates used to determine the benefit obligations were 6.10% and 6.50% for the years ended December 31, 2008 and 2007 respectively.

The assumed health care cost trend rates used to determine the benefit obligation as of the end of each year are as follows:

	December 31, 2008	December 31, 2007
Health care cost trend rate for next year	8.50% / 8.80% / 7.00%*	8.50%
Ultimate trend rate	5.00%	5.00%
Year that the rate reaches ultimate trend rate	2019	2013

* 8.5% represents the initial trend rate for pre-medicare claims, 8.8% for medicare-eligible, and 7.0% for the medicare supplement plan

Assumed health care cost trend rates have a significant effect on the amounts reported for the medical plans. A one-percentage point change in assumed health care cost trend rates would have the following aggregate effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In Thousands)	
Effect on total of service and interest costs components	$ 2,020	$ (1,626)
Effect on accumulated postretirement benefit obligation	$ 25,502	$ (20,896)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the periods noted:

	Expected Benefit Payments
	(In Thousands)
2009	$ 7,102
2010	7,835
2011	8,671
2012	9,313
2013	10,057
Years 2014 to 2018	55,528

Multi-Employer Benefits

Under the Coal Act, coal producers are required to fund medical and death benefits of certain retired union coal workers based on premiums assessed by the UMWA Benefit Funds. Based on available information at December 31, 2008, our obligation under the Coal Act was estimated at approximately $19.2 million, compared to our estimated obligation at December 31, 2007 of $19.8 million. The obligation was discounted using a 5.00% rate each year. We treat our obligation under the Coal Act as participation in a multi-employer plan and record the cost of our obligation as expense as payments are assessed. The expense related to this obligation for the years ended December 31, 2008, 2007 and 2006 totaled $2.3 million, $1.3 million and $4.3 million, respectively. The $1.3 million expense in 2007 was net of a $1.6 million refund from the UMWA Combined Benefit Fund ("CBF"). The refund was a result of the Tax Relief and Retiree Health Care Act of 2006 ("TRRHCA") enacted on December 20, 2006, which is detailed below.

The TRRHCA included important changes to the Coal Act that impacts all companies required to contribute to the CBF. Effective October 1, 2007, the Social Security Administration ("SSA") revoked all beneficiary assignments made to companies that did not sign a 1988 UMWA contract ("reachback companies") but their premium relief is phased-in. The reachback companies paid their full premium obligation in the current plan year that ended September 30, 2007. However, they paid only 55% of their plan year 2008 assessed premiums. They will pay only 40% of their plan year 2009 assessed premiums and 15% of their plan year 2010 assessed premiums. General United States Treasury money will be transferred to the CBF to make up the difference. After 2010, reachback companies will have no further obligations to the CBF, and transfers from the United States Treasury will cover all of the health care costs for retirees and dependents previously assigned to reachback companies. Some of our subsidiaries are considered reachback companies under the TRRHCA.

11. Workers' Compensation and Black Lung Benefits

Workers' compensation and black lung benefit obligation consisted of the following:

	December 31, 2008	December 31, 2007
	(In Thousands)	
Accrued self-insured black lung obligation	$ 50,739	$ 53,412
Workers' compensation (traumatic injury)	64,172	58,788
Total accrued workers' compensation and black lung	114,911	112,200
Less amount included in Other current liabilities	21,929	21,498
Workers' compensation & black lung in Other noncurrent liabilities	$ 92,982	$ 90,702

The amount of workers' compensation (traumatic liability) related to self-insurance was $59.1 million and $56.7 million at December 31, 2008 and 2007, respectively. Weighted average actuarial assumptions used in the determination of the self-insured portion of workers' compensation (traumatic injury) liability included a discount rate of 5.00% at December 31, 2008 and 2007, and the accumulated black lung obligation included a discount rate of 6.10% and 6.50% at December 31, 2008 and 2007, respectively.

A reconciliation of changes in the self-insured black lung obligation is as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007
	(In Thousands)	
Beginning of year accrued self-insured black lung obligation	$ 53,412	$ 53,284
Service cost	2,186	2,495
Interest cost	3,390	3,117
Actuarial gain	(6,524)	(3,989)
Benefit payments	(1,725)	(1,495)
Accrued self-insured black lung obligation	$ 50,739	$ 53,412

The table below details the changes to Accumulated other comprehensive loss related to black lung benefits in accordance with SFAS 158:

	2008	2007
	(In Thousands)	
	Net gain	Net gain
January 1 beginning balance	$ (10,587)	$ (10,102)
Changes to Accumulated other comprehensive loss	(1,851)	(485)
December 31 ending balance	(12,438)	(10,587)

We expect to recognize $4.1 million of net actuarial gain in 2009.

Expenses for black lung benefits and workers' compensation related benefits include the following components:

	Year Ended December 31, 2008	December 31, 2007	December 31, 2006
		(In Thousands)	
Self-insured black lung benefits:			
Service cost	$ 2,186	$ 2,495	$ 2,619
Interest cost	3,390	3,117	2,861
Amortization of actuarial gain	(3,489)	(3,194)	(3,759)
	2,087	2,418	1,721
Other workers' compensation benefits	27,965	30,842	36,381
	$ 30,052	$ 33,260	$ 38,102

Payments for benefits, premiums and other costs related to black lung and workers' compensation liabilities were $24.0 million, $29.6 million and $33.2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The actuarial assumptions used in the determination of self-insured black lung benefits expense included discount rates of 6.50%, 5.90% and 5.75% for the years ended December 31, 2008, 2007 and 2006, respectively.

Our self-insured black lung obligation is calculated using assumptions regarding future medical cost increases and cost of living increases. Federal black lung benefits are subject to cost of living increases. State benefits increase only until disability, and then remain constant. We assume a 6.50% annual medical cost increase and a 3.0% cost of living increase in determining our black lung obligation and the annual black lung expense. Assumed medical cost and cost of living increases significantly affect the amounts reported for our black lung expense and obligation. A one-percentage point change in each of assumed medical cost and cost of living trend rates would have the following effects:

	1-Percentage Point Increase	1-Percentage Point Decrease
Increase/decrease in medical cost trend rate:		
Effect on total of service and interest costs components	$ 183	$ (145)
Effect on accumulated black lung obligation	$ 1,376	$ (1,119)
Increase/decrease in cost of living trend rate:		
Effect on total service and interest cost components	$ 696	$ (558)

Effect on accumulated black lung obligation	$	5,548	$	(4,537)

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid related to the self-insured black lung obligation:

	Expected Benefit Payments
	(In Thousands)
2009	$ 2,867
2010	3,024
2011	3,181
2012	3,332
2013	3,478
Years 2014 to 2018	19,412

12. Stock Plans

We have stock incentive plans to encourage employees and nonemployee directors to remain with the Company and to more closely align their interests with those of our shareholders.

Description of Stock Plans

The Massey Energy Company 2006 Stock and Incentive Compensation Plan (the "2006 Plan"), which was approved by our shareholders and became effective on June 28, 2006 replaces the five stock-based compensation plans (the "Prior Plans") we had in place prior to the approval of the 2006 Plan, all of which had been approved by our shareholders. The Prior Plans include the following:

- Massey Energy Company 1996 Executive Stock Plan, as amended and restated effective November 30, 2000 (the "1996 Plan"),
- Massey Energy Company 1997 Stock Appreciation Rights Plan, as amended and restated effective November 30, 2000 (the "SAR Plan"),
- Massey Energy Company 1999 Executive Performance Incentive Plan, as amended and restated effective November 30, 2000 (the "1999 Plan"),
- Massey Energy Company Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1995 Plan"), and
- Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors, as amended and restated effective May 24, 2005 (the "1997 Plan").

Stock-based compensation has been granted under the 2006 Plan and the Prior Plans in the manner described below. Issued and outstanding stock-based compensation has been granted to officers and certain key employees in accordance with the provisions of the 1996 Plan, the SAR Plan, the 1999 Plan, and the 2006 Plan. Issued and outstanding stock-based compensation has been granted to non-employee directors in accordance with the provisions of the 1995 Plan, the 1997 Plan and the 2006 Plan. The Compensation Committee of the Board of Directors administers the 1996 Plan, the 1999 Plan, the SAR Plan and the 2006 Plan. A committee comprised of non-participating board members administers the 1995 Plan and the 1997 Plan.

The 1996 Plan provided for grants of stock options and restricted stock. The 1999 Plan provided for grants of stock options, restricted stock, incentive awards and stock units. The SAR Plan provided for grants of SARs. The 1995 Plan provided for grants of restricted stock and restricted units. The 1997 Plan provided for grants of restricted stock. As of June 28, 2006, grants can no longer be made under the Prior Plans, except for the 1996 Plan, under which grants could no longer be made as of March 2, 2006. All awards previously granted that are outstanding under the Prior Plans will remain effective in accordance with the terms of their grant.

The aggregate number of shares of Common Stock that may be issued for future grant under the 2006 Plan as of December 31, 2008 was 1,362,752 shares, which was computed as the 3,500,000 shares specifically authorized in the 2006 Plan, less grants made in 2006, 2007 and 2008, plus the number of shares that (i) were represented by restricted stock or unexercised vested or unvested stock options that previously have been granted and were outstanding under the Prior Plans as of June 28, 2006 and (ii) expire or otherwise lapse, are terminated or forfeited, are settled in cash, or are withheld or delivered to us for tax purposes at any time after June 28, 2006. The 2006 Plan provides for grants of stock options, SARs, restricted stock, restricted units, unrestricted stock and incentive awards.

Although we have not expressed any intent to do so, we have the right to amend, suspend, or terminate the 2006 Plan at any time by action of our board of directors. However, no termination, amendment or modification of the 2006 Plan shall in any manner adversely affect any award theretofore granted under the 2006 Plan, without the written consent of the participant. If a change in control were to occur (as defined in the plan documents), certain options may become immediately vested, but only upon termination of the option holder's service.

Accounting for Stock-Based Compensation

Total compensation expense recognized for stock-based compensation during the year ended December 31, 2008, 2007 and 2006 was $10.5 million, $19.2 million and $7.3 million, respectively. The total income tax benefit recognized in the consolidated statement of income for share based compensation arrangements during the year ended December 31, 2008, 2007 and 2006 was approximately $4.1 million, $7.5 million and $2.8 million, respectively. We recognize compensation expense on a straight-line basis over the vesting period for the entire award for any awards with graded vesting.

As a result of adopting FAS 123R, we recognized non-cash stock-based compensation expense for stock options of approximately $6.1 million (pre-tax) in Selling, general and administrative expense for the year ended December 31, 2006. The total income tax benefit recognized on this compensation expense was approximately $2.4 million. Income before income taxes, Net income and Earnings per share for the year ended December 31, 2006 were $6.1 million, $3.7 million and $0.05 lower, respectively, than if we had continued to account for share-based compensation under APB No. 25. As of December 31, 2008 and 2007, there was $8.4 million and $11.1 million, respectively, of total unrecognized compensation cost related to stock options expected to be recognized over a weighted-average period of approximately 1.8 years. In the years ended December 31, 2008 and 2007, we also reflected ($1.2) million and $0.4 million, respectively, of excess tax benefits (expenses) as a financing cash flow in the consolidated statement of cash flows resulting from the exercise of stock options.

Equity instruments

We have granted stock options to employees under the 2006 Plan, the 1999 Plan and the 1996 Plan. These options typically have a requisite service period of three to four years, though there are some awards outstanding with requisite service periods of one year up to four years. Vesting generally occurs ratably over the requisite service period. The maximum contractual term of stock options granted is 10 years.

We value stock options using the Black-Scholes valuation model, which employs certain key assumptions. We estimate volatility using both historical and market data over the term of the options granted. The dividend yield is calculated on the current annualized dividend payment and the stock price at the date of grant. The expected option life is based on historical data and exercise behavior. The risk-free interest rate is based on the zero-coupon Treasury bond rate in effect at the date of grant. The fair value of options granted during the three years ended December 31, 2008, 2007 and 2006 was calculated using the following assumptions:

	Years Ended December 31,		
Options Granted	2008	2007	2006
Number of shares underlying options	798,647	556,979	642,434
Contractual term in years	10	10	10
Assumptions used to estimate fair value:			
Expected volatility	50% - 100%	46% - 50%	46% - 55%
Weighted average volatility	71%	50%	46%
Expected option life in years	1.3 - 4.3	1.2 - 4.3	1.2 - 5.0
Dividend yield	0.4% - 1.5%	0.6% - 0.7%	0.4% - 0.7%
Risk-free interest rate	0.9% - 3.1%	3.0% - 4.7%	4.2% - 4.8%
Weighted-average fair value estimates at grant date:			
In thousands	$ 6,820	$ 5,542	$ 5,192
Fair value per share	$ 8.54	$ 9.95	$ 8.08

A summary of option activity under the plans for the year ended December 31, 2008 is presented below:

	Number of Options	Weighted average exercise price	Weighted average contractual term (years)	Aggregate Intrinsic Value
	(In Thousands, Except Exercise Price and Contractual Term)			
Outstanding at December 31, 2007	2,674	$ 26.39		
Granted	799	19.64		
Exercised	(787)	20.99		
Forfeited/expired	(73)	31.76		
Outstanding at December 31, 2008	2,613	$ 25.81	7.9	$ 382
Exercisable at December 31, 2008	1,375	$ 28.00	6.6	$ 382

We received $16.5 million, $4.0 million and $2.1 million in cash proceeds from the exercise of stock options for the years ended December 31, 2008, 2007 and 2006, respectively. The intrinsic value of stock options exercised was $18.4 million, $4.5 million and $3.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

We have granted restricted stock to our employees under the 2006 Plan and 1999 Plan and to non-employee directors under the 1995 Plan and 1997 Plan. Restricted stock awards are valued on the date of grant based on the closing value of our stock. As of December 31, 2008, there was $11.3 million of unrecognized compensation cost related to restricted stock expected to be recognized over the next three years. With the adoption of FAS 123R, unearned compensation is recorded on a net basis in Additional capital.

A summary of the status of restricted stock at December 31, 2008, and changes for the year then ended is presented below:

(Shares In Thousands)	Shares	Weighted average grant date fair value
Unvested at December 31, 2007	515	$ 28.64
Granted	344	$ 22.21
Vested	(232)	$ 28.97
Forfeited	(32)	$ 29.12
Unvested at December 31, 2008	595	$ 24.76

The fair value of restricted stock vested during the years ended December 31, 2008, 2007 and 2006 was $6.7 million, $3.8 million and $3.6 million, respectively.

Liability instruments

We use the fair value method to recognize compensation cost associated with SARs. At each December 31, 2008, 2007 and 2006, there were 262,500 vested SARs outstanding and exercisable. The weighted average exercise price of these SARs was $29.19 per SAR; the weighted average contractual term was 4.8 years.

We also issue stock incentive units, which are classified as liabilities. They are settled with a cash payment for each unit vested, equal to the fair market value of Common Stock on the vesting date.

	For the years ended December 31, 2008	2007
Awarded	399,687	310,900
Settled	131,981	81,461
Settlement amount (in millions)	$ 2.4	$ 2.3

13. Lease Obligations

We lease certain mining and other equipment under various lease agreements. Certain of these leases provide options for the purchase of the property at the end of the initial lease term, generally at its then fair market value, or to extend the terms at its then fair rental value. Certain of these leases contain financial or other non-performance covenants that may require an accelerated buyout of the lease if the covenants are violated. Rental expense for the years ended December 31, 2008, 2007 and 2006 was $53.1 million, $39.7 million and $46.4 million, respectively.

During 2008, 2007 and 2006 we sold and leased-back certain mining equipment. We received net proceeds of $41.3 million, $13.1 million and $21.8 million, for the years ended December 31, 2008, 2007 and 2006, respectively, resulting in net deferred gains of $2.4 million and $1.2 million for the years ended December 31, 2008 and 2007, respectively. No gain or loss was recognized on the sale and lease-back transactions that occurred in the year ended December 31, 2006. The gains are being recognized ratably over the term of the leases, which range from 3.5 to 7 years. At lease termination, the leases contain renewal and purchase options at an amount approximating fair value. The leases are being accounted for as operating leases.

The following presents future minimum rental payments, by year, required under leases with initial terms greater than one year, in effect at December 31, 2008:

	Capital Leases	Operating Leases
	(In Thousands)	
2009	$ 2,285	$ 71,237
2010	2,412	70,150
2011	2,670	56,527
2012	13	46,177
2013	12	29,654
Beyond 2013	23	18,850
Total minimum lease payments	7,415	$ 292,595
Less imputed interest	503	
Present value of minimum capital lease payments	$ 6,912	

14. Concentrations of Credit Risk and Major Customers

We are engaged in the production of coal for the utility industry, steel industry and industrial markets. The following chart lists the percentage of each type of Produced coal revenue generated by market:

	For the years ended December 31, 2008	2007	2006
Utility coal	53%	60%	62%
Metallurgical coal	37%	30%	28%
Industrial coal	10%	10%	10%

Our mining operations are conducted in southern West Virginia, eastern Kentucky and western Virginia. We market our produced and purchased coal to customers in the United States and in international markets, including Canada and various European and Asian countries. For the years ended December 31, 2008, 2007, and 2006 approximately 30%, 16%, and 15%, respectively, of Produced coal revenue was attributable to sales to customers outside of the United States.

For the year ended December 31, 2008, approximately 11% of Produced coal revenue was attributable to sales to Constellation Energy Commodities Group, Inc. ("Constellation"). For both the years ended December 31, 2007 and 2006, approximately 11% of Produced coal revenue was attributable to sales to affiliates of American Electric Power Company, Inc. At December 31, 2008, approximately 75%, 13% and 12% of Trade receivables represents amounts due from utility customers, metallurgical customers and industrial customers, respectively, compared with 56%, 28% and 16%, respectively, as of December 31, 2007. For fiscal year 2009, our contracted sales to Constellation currently represent approximately 26% of our projected produced coal tonnage and 18% of our projected Produced coal revenue.

Our Trade and other accounts receivable are subject to potential default by customers. In prior years, certain of our customers have filed for bankruptcy resulting in bad debt charges. In an effort to mitigate credit-related risks in all customer classifications, we maintain a credit policy, which requires scheduled reviews of customer creditworthiness and continuous monitoring of customer news events that might have an impact on their financial condition. Negative credit performance or events may trigger the application of tighter terms of sale, requirements for collateral or guarantees or, ultimately, a suspension of credit privileges. We establish bad debt reserves to specifically consider customers in financial difficulty and other potential receivable losses. In establishing the reserve, we consider the financial condition of individual customers and probability of recovery in the event of default. We charge off uncollectible receivables once legal potential for recovery is exhausted. See Note 18 for a discussion of certain customer disputes.

15. Derivative Instruments

We evaluate each of our coal sales and coal purchase forward contracts under SFAS 133 to determine in they qualify for the NPNS exception prescribed by SFAS 133. The majority of our forward contracts do qualify for the NPNS exception based on management's intent and ability to physically deliver or take physical delivery of the coal. For those contracts that do not qualify for NPNS, the contracts are required to be accounted for as derivative instruments in accordance with SFAS 133, which requires all derivative instruments to be recognized as assets or liabilities and to be measured at fair value. Those contracts that have been identified as derivatives have not been designated as cash flow or fair value hedges and, accordingly, the net change in fair value is recorded in current period earnings. As of December 31, 2008, there were approximately 1.8 million and 2.2 million tons outstanding under these coal purchase and coal sales contracts, respectively. We have recorded net unrealized losses of $22.6 million related to coal sales and purchase contracts that qualify as derivatives in the Consolidated Statements of Income for the twelve months ending December 31, 2008 under the caption Net change in fair value of derivative instruments. A liability of $22.6 million is included in Other current liabilities in the Consolidated Balance Sheets as of December 31, 2008 as all of these contracts have terms of one year or less.

16. Fair Value of Financial Instruments

On January 1, 2008, we adopted SFAS 157, which requires the categorization of financial assets and liabilities based upon the level of judgments associated with the inputs used to measure their fair value. Hierarchical levels – defined by SFAS 157 and directly related to the amount of subjectivity associated with the inputs used to determine the fair value of financial assets and liabilities – are as follows:

- Level 1 – Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.
- Level 2 – Inputs (other than quoted prices included in Level 1) are either directly or indirectly observable for the assets or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.
- Level 3 – Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Each major category of financial assets and liabilities measured at fair value on a recurring basis are categorized in the tables below based upon the lowest level of significant input to the valuations.

	December 31, 2008 (In Thousands)			
	Level 1	Level 2	Level 3	Total
Fixed income securities	$ 13,039	$ -	$ -	$ 13,039
Money market funds	616,118	-	-	616,118
Short-term investment	-	-	39,383	39,383
Derivative instruments	-	22,552	-	22,552
Total securities	$ 629,157	$ 22,552	$ 39,383	$ 691,092

All investments in money market funds are cash equivalents or deposits pledged as collateral and are primarily invested in seven money market funds and four Treasury-backed funds. All fixed income securities are deposits, consisting of obligations of the U.S. Treasury, supporting various regulatory obligations. See Note 3 to the Notes to Consolidated Financial Statements for more information on deposits.

Short-term investment is comprised of an investment in the Primary Fund, a money market fund that has suspended redemptions and is being liquidated. We have determined that our investment in the Primary Fund no longer meets the definition of a security within the scope of SFAS 115, since the equity investment no longer has a readily determinable fair value. Therefore, the investment has been classified as a short-term investment, subject to the cost method of accounting, on our Consolidated Balance Sheet. This classification as a short-term investment is based on our assessment of each of the individual securities that make up the underlying portfolio holdings in the Primary Fund, which primarily consisted of commercial paper and discount notes having maturity dates within the next 12 months, and the stated notifications from the Primary Fund that they expect to liquidate substantially all of their holdings and make distributions within a year.

Assets Measured at Fair Value on a Recurring Basis Using Significant Unobservable Inputs (Level 3):

(In Thousands)	Short-term Investments
Balance at December 31, 2007	$ -
Transfers in (out) of Level 3, net	45,920
Change in fair value included in earnings	(6,537)
Balance at December 31, 2008	$ 39,383
Losses included in earnings attributable to the change in unrealized losses relating to assets still held at December 31, 2008	$ (6,537)

The original cost of our investment in the Primary Fund was $217.9 million. In mid-September, the Primary Fund reported a net asset value of $0.97 per share as a result of the Primary Fund's valuing at zero its holdings of debt securities issued by Lehman Brothers Holdings, Inc., which filed for bankruptcy on September 15, 2008. Given that the Primary Fund is in liquidation, we believe that other than temporary impairment is evident. Based on our assessment of the Primary Fund's net asset value, the planned disbursement schedule of the Primary Fund's cash and the underlying securities held by the Primary Fund, we have determined that the approximate fair value of our investment as of September 30, 2008 was $211.4 million, which represents our investment in the Primary Fund at 97% of its cost. We have recorded a loss of $6.5 million which represents the difference between cost and estimated fair value.

In September 2008, we requested the redemption of our investment in the Primary Fund. On October 31, 2008 and December 3, 2008, the Primary Fund made distributions to us of $110.7 million and $61.3 million, respectively, leaving an investment balance of $39.4 million. Subsequent to December 31, 2008, on February 20, 2009, the Primary Fund made an additional distribution to us of $14.5 million. While we expect to receive substantially all of our remaining holdings in the Primary Fund during 2009, we cannot predict when this will occur or the actual amount we will eventually receive. Accordingly, we have reclassified our investment from Cash and cash equivalents to Short-term investment on our Consolidated Balance Sheet as of December 31, 2008.

Certain of our coal sales and coal purchase forward contracts are accounted for as derivative instruments in accordance with SFAS 133. SFAS 133 requires all derivative instruments to be recognized as assets or liabilities and to be measured at fair value. To establish fair values for these contracts, we use bid/ask price quotations obtained from independent third-party brokers. We could experience difficulty in valuing our derivative instruments if the number of third-party brokers should decrease or market liquidity is reduced.

17. Common Stock Issuance

On August 12, 2008, we completed a registered underwritten public offering of 4,370,000 shares of Common Stock, which included 2,874,800 shares of our Treasury stock, at a public offering price of $61.50 per share, resulting in proceeds to us of $258.2 million, net of underwriting fees. As discussed in Note 6, we used these proceeds and the proceeds of the concurrent convertible notes offering to purchase a portion of the 6.625% Notes in connection with the 6.625% Notes consent solicitation and tender offer and for general corporate purposes.

18. Contingencies

Wheeling-Pittsburgh

On April 27, 2005, Wheeling-Pittsburgh sued our subsidiary, Central West Virginia Energy Company ("CWVE"), in the Circuit Court of Brooke County, West Virginia, seeking (a) an order requiring CWVE to specifically perform its obligations under a Coal Supply Agreement ("CSA") and (b) compensatory damages due to CWVE's alleged failure to perform under the CSA and for alleged damages to Wheeling-Pittsburgh's coke ovens. Wheeling-Pittsburgh later amended its complaint to add Mountain State Carbon, LLC ("MSC") as a plaintiff, us as a defendant, and claims for bad faith, misrepresentation and punitive damages. It is CWVE's position that its failure to perform was excused due to the occurrence of events that rendered performance commercially impracticable and/or *force majeure* events as defined by the parties in the CSA, including unforeseen labor shortages, mining and geologic problems at certain of our coal mines, railroad car shortages, transportation problems and other events beyond our control.

On May 29, 2007, the trial commenced. On July 2, 2007, the jury awarded damages in favor of Wheeling-Pittsburgh and MSC in the amount of $219.9 million, comprising $119.9 million compensatory damages for breach of contract and misrepresentation and $100 million for punitive damages. On July 30, 2007, a hearing was held by the trial court to review the punitive damages award, and to consider pre-judgment interest and a counterclaim filed by CWVE related to damages for non-payment of the escalated purchase price under the CSA for coal delivered to MSC in November and December 2006. At the hearing, the trial court awarded Wheeling-Pittsburgh and MSC pre-judgment interest of approximately $24 million and awarded CWVE approximately $4.5 million (including pre-judgment interest) on the counterclaim. On August 2, 2007, the trial court entered the jury award of compensatory and punitive damages, which, including the above mentioned pre-judgment interest of $24 million, totaled approximately $240 million (net of the $4.5 million awarded to CWVE). On September 26, 2007, the trial court held a hearing on the issue of security for the judgment pending appeal to the Supreme Court of Appeals of West Virginia ("WV Supreme Court"). On September 28, 2007, the trial court ordered that a bond be posted in the amount of $50 million. The $50 million appeal bond was posted with the trial court on October 25, 2007.

On December 10, 2007, we and CWVE filed separate "Petitions for Appeal" with the WV Supreme Court seeking, among other things, review of certain rulings made by the trial court and reversal of the judgments against us. The arguments raised on appeal included, among other things, (i) the propriety of allowing Wheeling-Pittsburgh to proceed with both contract and tort claims where the tort arose out of performance of the contract, (ii) the propriety of the punitive damages award, (iii) whether Wheeling-Pittsburgh proved the elements of its misrepresentation and contract claims and (iv) the correctness of certain evidentiary rulings.

We believed, in consultation with legal counsel, that we had strong legal arguments to raise on appeal to the WV Supreme Court that created significant uncertainty regarding the ultimate outcome of this matter. Given the size of the punitive damages awarded, West Virginia case precedent, and the significant legal questions the case presented for appeal, we believed it was probable that the WV Supreme Court would agree to hear our appeal. Ultimately, we believed it was unlikely any punitive damages would be assessed in this matter. We further believed in consultation with legal counsel that due to matters of law in the conduct of the trial, there was a strong possibility that the WV Supreme Court would remand the compensatory damages claim for retrial or significantly reduce the amount of the compensatory damages awarded by the jury.

We believed the range of possible loss in this matter was from $16 million to $244 million, prior to post-judgment interest or other costs. The minimum loss we expected to incur upon final settlement or adjudication was the amount of excess costs incurred by Wheeling-Pittsburgh to acquire coal required but not delivered under the CSA (plus pre-judgment interest) adjusted for performance excused by events of *force majeure*. We were unable to predict the ultimate outcome of this matter and believed there was no amount in the range that was a better estimate than any other amount given the various possible outcomes on appeal. Included in these reasonably possible outcomes were reversal of the compensatory damage and punitive awards, remand and retrial, or reduction of some or all of the awards. As there was no amount in the range that was a better estimate than any other amount, the minimum amount in the range of $16.0 million (plus accrued interest) had been accrued as of March 31, 2008.

On May 22, 2008, the WV Supreme Court decided not to hear an appeal of the verdicts against us or CWVE. In the second and third quarters of 2008, we increased our legal accrual for this case by $245.3 and $5.8 million in the Litigation charge line item on our Consolidated Income Statement, respectively, for a total accrual as of September 30, 2008, of $268.5 million, including interest, recorded in Other current liabilities. On December 1, 2008, the United States Supreme Court declined to accept the petitions for certiorari filed on behalf of us and CWVE. On December 4, 2008, we paid the total amount of $267.4 million (which included the release of a $50.0 million appeal bond), which represented the entire judgment against us and CWVE, including all applicable interest payments. On December 8, 2008, the Circuit Court of Brooke County entered an Order finding satisfaction of the judgment and discharging any and all liens in connection with that judgment. In addition, on December 8, 2008, the Circuit Court of Brooke County released us from any and all obligations under the appeal bond posted in connection with this litigation.

We have notified our insurance carriers pursuant to our insurance policies. We believe that we have a valid claim for coverage for at least certain aspects of the underlying litigation. However, we are not able at this time to predict with any degree of certainty the amount of any insurance recovery.

Harman

In December 1997, A.T. Massey's then subsidiary, Wellmore Coal Corporation ("Wellmore"), declared force majeure under its coal supply agreement with Harman Mining Corporation ("Harman") and reduced the amount of coal to be purchased from Harman. On October 29, 1998, Harman and its sole shareholder sued A.T. Massey and five of its other subsidiaries (the "Massey Defendants") in the Circuit Court of Boone County, West Virginia, alleging that the Massey Defendants tortiously interfered with Wellmore's agreement with Harman, causing Harman to go out of business. On August 1, 2002, the jury awarded the plaintiffs $50 million in compensatory and punitive damages. On October 24, 2006, the Massey Defendants timely filed their Petition for Appeal to the WV Supreme Court. On November 21, 2007, the WV Supreme Court issued a 3-2 majority opinion reversing the judgment against the Massey Defendants and remanding the case to the Circuit Court of Boone County with directions to enter an order dismissing the case, with prejudice, in its entirety. The Harman plaintiffs filed motions asking the WV Supreme Court to conduct a rehearing in the case. On January 24, 2008, the WV Supreme Court decided to rehear the case, which was re-argued on March 12, 2008. On April 3, 2008, the WV Supreme Court again reversed the judgment against the Massey Defendants and remanded the case with direction to enter an order dismissing the case, with prejudice, in its entirety. In July 2008, the Harman plaintiffs petitioned the United States Supreme Court to review the WV Supreme Court's dismissal of their claims.

In December 2008, the U.S. Supreme Court agreed to review the case. The U.S. Supreme Court granted review based on the question of whether a justice of the WV Supreme Court should have recused himself from the appeal. Oral argument before the U.S Supreme Court is scheduled for March 3, 2009. The U.S Supreme Court could affirm the dismissal of the case by the WV Supreme Court or direct the WV Supreme Court to rehear the case. If the WV Supreme Court, which is comprised of five justices, rehears the case the matter would not be heard by the same five justices who heard the matter in April 2008. The justices of the reconfigured WV Supreme Court could dismiss the plaintiffs' claims again, or reach some different result, including a reinstatement of the original verdict against us with interest. We believe the range of possible loss in this matter is from zero to $82 million as of December 31, 2008, including post-judgment interest and other costs. We are unable to predict the ultimate outcome of this matter and believe there is no amount in the range that is a better estimate than any other amount given the various possible outcomes. As there is no amount in the range that is a better estimate than any other amount and the minimum amount in the range is zero, we have not recorded an accrual for this matter. It is reasonably possible that our judgments regarding these matters could change in the near term, resulting in the recording of material losses that would affect our operating results and financial position.

West Virginia Flooding

Since July 2001, we and nine of our subsidiaries have been sued in 17 consolidated civil actions filed in the Circuit Courts of Boone, Fayette, Kanawha, McDowell, Mercer, Raleigh and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 8, 2001. Along with 32 other consolidated cases not involving us or our subsidiaries, these cases cover approximately 1,800 plaintiffs seeking unquantified compensatory and punitive damages against approximately 100 defendants. The WV Supreme Court transferred all 49 cases (the "Referred Cases") to the Circuit Court of Raleigh County, West Virginia, to be handled by a mass litigation panel, which originally assigned three of its six judges to preside (the "Panel") over the litigation.

On January 18, 2007, a panel judge dismissed all claims asserted by all plaintiffs within the Coal River watershed in Raleigh County, West Virginia. Plaintiffs filed a petition seeking appeal of this decision with the WV Supreme Court, which was granted on October 24, 2007. The WV Supreme Court issued a decision on June 26, 2008 reversing the lower court and in early September 2008 denied a Motion for Rehearing and remanded the case to the Mass Litigation Panel for further proceedings. We expect proceedings to resume in early to mid-2009. We believe we have insurance coverage applicable to these items.

Since August 2004, five of our subsidiaries have been sued in six civil actions filed in the Circuit Courts of Boone, McDowell, Mingo, Raleigh, Summers and Wyoming Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about May 2, 2002. These complaints cover approximately 350 plaintiffs seeking unquantified compensatory and punitive damages from approximately 35 defendants.

Since May 2006, we and twelve of our subsidiaries have been sued in three civil actions filed in the Circuit Courts of Logan and Mingo Counties, West Virginia, for alleged property damages and personal injuries arising out of flooding between May 30 and June 4, 2004. Four of our subsidiaries have been dismissed from one of the Logan County cases. These complaints cover approximately 425 plaintiffs seeking unquantified compensatory and punitive damages from approximately 52 defendants. Two of these cases (both in Logan County) were stayed pending appeal of the Coal River watershed decision noted above. One case is now proceeding and we expect the other case and the Mingo County case to resume soon.

On April 10, 2007, two of our subsidiaries were sued in a civil action filed in the Circuit Court of Boone County, West Virginia, for alleged property damages and personal injuries arising out of flooding on or about July 29, 2001. This complaint covers 17 plaintiffs seeking unquantified compensatory and punitive damages from five defendants. On November 6, 2007, we filed a motion to dismiss, or in the alternative, to certify questions to the WV Supreme Court in response to the complaint. Subsequently, we settled with 16 of 17 of the plaintiffs. With respect to the remaining plaintiff, the trial court granted a motion to withdraw filed by the plaintiff's counsel and subsequently dismissed the remaining plaintiff on the grounds initially asserted in the motion to dismiss. The appeal period regarding the dismissal has run and this case is now closed.

We believe these matters will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

West Virginia Trucking

Since January 2003, an advocacy group and residents in Boone, Kanawha, Mingo and Raleigh Counties, West Virginia, filed 17 suits in the Circuit Courts of Kanawha and Mingo Counties, West Virginia, against twelve of our subsidiaries. Plaintiffs alleged that defendants illegally transported coal in overloaded trucks, causing damage to state roads, thereby interfering with plaintiffs' use and enjoyment of their properties and their right to use the public roads. Plaintiffs seek injunctive relief and compensatory and punitive damages. The WV Supreme Court referred the consolidated lawsuits, and similar lawsuits against other coal and transportation companies not involving our subsidiaries, to the Circuit Court of Lincoln County, West Virginia, to be handled by a mass litigation panel judge. Plaintiffs filed motions requesting class certification. On June 7, 2007, plaintiffs voluntarily dismissed their public nuisance claims seeking monetary damages for road and bridge repairs. Defendants filed a motion requesting that the mass litigation panel judge recommend to the WV Supreme Court that the cases be sent back to the circuit courts of origin for resolution. That motion has not been ruled upon. Defendants moved to dismiss any remaining public nuisance claims and to limit any damages for nuisance to two years prior to the filing of any suit, and plaintiffs agreed to an order limiting any damages for nuisance to two years prior to the filing of any suit. The motion to dismiss any remaining public nuisance claims was resisted by plaintiffs and argued at hearings on December 14, 2007 and June 25, 2008. As of February 12, 2009, no date has been set for trial. We believe we have insurance coverage applicable to these items and that they will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

Well Water Contamination

Since September 2004, approximately 710 plaintiffs have filed approximately 400 suits against us and our subsidiary, Rawl Sales & Processing Co., in the Circuit Court of Mingo County, West Virginia, for alleged property damage and personal injuries arising out of slurry injection and impoundment practices allegedly contaminating plaintiffs' water wells. Subsequent to such filings, approximately 55 suits have either been voluntarily dismissed by the plaintiffs or dismissed by the Circuit Court. Plaintiffs seek injunctive relief and compensatory damages in excess of $170 million and unquantified punitive damages. Specifically, plaintiffs are claiming that defendants' activities during the period of 1978 through 1987 rendered their property valueless and request monetary damages to pay, *inter alia*, the value of their property and future water bills. In addition, many plaintiffs are also claiming that their exposure to the contaminated well water caused neurological injury or physical injury, including cancers, kidney problems and gall stones. Finally, all plaintiffs are claiming entitlement to medical monitoring for the next 30 years. Plaintiffs also request unliquidated compensatory damages for pain and suffering, annoyance and inconvenience and legal fees. The trial has been continued multiple times and is currently scheduled for May 12, 2009. We do not believe there was any contamination caused by our activities or that plaintiffs suffered any damage and, therefore, we do not believe we have a probable loss related to this matter. We plan to vigorously contest these claims. We believe that we have insurance coverage applicable to these matters and have initiated litigation against our insurers to establish that coverage. At this time, we believe that the litigation by the plaintiffs will be resolved without a material adverse impact on our cash flows, results of operations or financial condition.

Surface Mining Fills

Since September 2005, three environmental groups sued the United States Army Corps of Engineers ("Corps") in the United States District Court for the Southern District of West Virginia (the "District Court"), asserting the Corps unlawfully issued permits to four of our surface mines to construct mining fills. The suit alleges the Corps failed to comply with the requirements of both Section 404 of the Clean Water Act and the National Environmental Policy Act, including preparing environmental impact statements for individual permits. We intervened in the suit to protect our interests. On March 23, 2007, the District Court rescinded four of our subsidiaries' permits, resulting in the temporary suspension of mining at these surface mines. We appealed that ruling to the United States Court of Appeals for the Fourth Circuit (the "Fourth Circuit Court"). On April 17, 2007, the District Court partially stayed its ruling, permitting mining to resume in certain fills that were already under construction. On June 14, 2007, the District Court issued an additional ruling, finding the Corps improperly approved placement of sediment ponds in streams below fills on the four permits in question. The District Court subsequently modified its ruling to allow these ponds to remain in place, as the ponds and fills have already been constructed. The District Court's ruling could impact the issuance of permits for the placement of sediment ponds for future operations. If the permits for the fills or sediment ponds are ultimately held to be unlawfully issued, production could be affected at these surface mines, and the process of obtaining new Corps permits for all surface mines could become more difficult. We appealed both rulings to the Fourth Circuit Court. A hearing on these appeals was held on September 23, 2008, and on February 13, 2009, the Fourth Circuit Court reversed the prior rulings of the District Court and remanded the matter for further proceedings. Given this development, we do not expect any material adverse impact to our operations.

Aracoma Mine Fire

In January 2006, one of our subsidiaries, Aracoma Coal Company, Inc. ("Aracoma"), experienced a mine fire that resulted in the deaths of two miners. The estates of the two miners had filed a lawsuit in the Circuit Court of Logan County against us, A.T. Massey and Aracoma with respect to the incident. A trial in that suit began on October 27, 2008. A settlement was reached and paid in December 2008, with a portion of the settlement being paid through insurance proceeds.

Additionally, the United States Attorney's Office in the Southern District of West Virginia ("U.S. Attorney's Office") and the Federal Mine Safety and Health Administration ("MSHA") conducted separate investigations into the incident. As a result of those investigations, Aracoma pleaded guilty to federal charges and agreed to pay $2.5 million in criminal fines and reached a settlement with MSHA in which Aracoma agreed to pay $1.7 million in administrative penalties. The plea will be presented for final review and approval at a hearing scheduled for April 15, 2009. These fines and penalties were fully accrued as of December 31, 2008 and have now been paid. There will be no fines or penalties imposed upon our affiliated companies for the incident.

Customer Disputes

We have customers who claim they did not receive, or did not timely receive, all of the coal required to be shipped to them during 2008 ("unshipped tons"). In such cases, it is typical for a customer and coal producer to agree upon a schedule for shipping unshipped tons in subsequent years. However, a few of our customers have notified us of claims or potential claims for cover damages, which are equal to the difference between the contract price of the coal that was not delivered and the market price of replacement coal or comparable quality coal.

We believe we have valid defenses to these claims or potential claims for cover damages. In many cases, there was untimely or insufficient delivery of railcars by the rail carrier or the customer. In other cases, factors beyond our control caused production or shipment problems. Additionally, we believe that certain customers previously agreed to accept unshipped tons in subsequent years. We believe that all of these factors, and other factors, provide defenses to claims or potential claims for unshipped tons.

We are currently in the process of arbitration and litigation over multiple claims for cover by one customer. In October and November 2008, this customer failed to pay approximately $35 million owed to us for several shipments of coal. The customer notified us that it had offset the amounts from its required payments in response to damages allegedly suffered due to alleged shortfalls that occurred prior to September 30, 2008. We believe this offset was improper and are pursuing collection of the amounts offset through a demand for arbitration filed against the customer in December 2008 and through our response to litigation initiated by the customer on a portion of the shortfalls. Additionally, one other customer filed suit in February 2009 seeking unspecified damages relating to alleged shortfalls and other customers have notified us of claims or potential claims for cover damages that have not yet resulted in litigation. Discussions with these customers remain ongoing.

Separately, we are currently in talks with a few other customers regarding disagreements over other contract matters. Specifically, we have disputes with two customers regarding whether or not binding contracts for the sale of coal were reached. One of these customers has terminated a signed, higher-priced contract and argues that it was only required to purchase coal under an agreement reached by email. The other customer argues that it reached agreement with us in the absence of a signed agreement and has brought litigation against us for not honoring the alleged unsigned agreement. We do not believe that we have failed to honor any binding agreement with these customers.

We believe that we have strong defenses to these claims and potential claims and further feel that many or all of these claims may be resolved without litigation. We have recorded an accrual for our best estimate of probable losses related to these matters. While we believe that all of these matters discussed above will be resolved without a material adverse impact on our cash flows, results of operations or financial condition, it is reasonably possible that our judgments regarding some or all of these matters could change in the near term. The aggregate exposure related to these claims in excess of our accrual is up to $105 million of charges that would affect our future operating results and financial position.

Spartan Unfair Labor Practice Matter & Related Age Discrimination Class Action

In 2005, the UMWA filed an unfair labor practice charge with the National Labor Relations Board (“NLRB”) alleging that Spartan Mining Company (“Spartan”) discriminated on the basis of anti-union animus in its employment offers. The NLRB issued a complaint and an NLRB Administrative Law Judge (“ALJ”) issued a recommended decision making detailed findings that the Company committed a number of unfair labor practice violations and awarding, among other relief, backpay damages to union discriminatees. The ALJ’s decision is on appeal to the NLRB. There is no insurance coverage applicable to the unfair labor practice matter; however, its resolution is not expected to materially impact our finances or operations.

On November 1, 2006, a class action age discrimination civil case was filed in West Virginia’s Fayette County Circuit Court. The suit alleges that Spartan discriminated against employment applicants on the basis of age. The class includes approximately 232 individuals, 85 of whom are also union discriminatees at issue in the ALJ’s decision.

In the civil suit, the age discrimination plaintiffs seek back pay, front pay, punitive damages, and other compensatory damages, plus attorney fees. We have insurance coverage applicable to the class action and believe that it will be resolved without material impact on our cash flows, results of operations or financial condition.

Other Legal Proceedings

We are parties to a number of other legal proceedings, incident to our normal business activities. These include contract dispute, personal injury, property damage and employment matters. While we cannot predict the outcome of these proceedings, based on our current estimates we do not believe that any liability arising from these matters individually or in the aggregate should have a material adverse impact upon our consolidated cash flows, results of operations or financial condition. It is possible, however, that the ultimate liabilities in the future with respect to these lawsuits and claims, in the aggregate, may be materially adverse to our cash flows, results of operations or financial condition.

19. Quarterly Information (Unaudited)

The table below details our quarterly financial information for the previous two fiscal years.

	Three Months Ended			
	March 31, 2008 (1)	June 30, 2008 (2)	September 30, 2008 (3)	December 31, 2008 (4)
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 644,625	$ 826,838	$ 763,296	$ 755,030
Income (loss) before interest and taxes	68,975	(108,574)	93,490	79,331
Income (loss) before taxes	53,239	(125,794)	64,782	68,106
Net income (loss)	41,934	(93,338)	54,026	53,626
Net income (loss) per share:				
Basic	$ 0.53	$ (1.16)	$ 0.65	$ 0.63
Diluted	$ 0.52	$ (1.16)	$ 0.64	$ 0.63

	Three Months Ended			
	March 31, 2007	June 30, 2007 (5)	September 30, 2007	December 31, 2007 (6)
	(In Thousands, Except Per Share Amounts)			
Total revenue	$ 607,320	$ 617,802	$ 603,441	$ 584,960
Income before interest and taxes	55,557	60,127	35,343	28,652
Income before taxes	39,531	45,316	20,478	24,178
Net income	32,607	34,938	21,408	5,145
Net income per share (basic and diluted)	$ 0.40	$ 0.43	$ 0.27	$ 0.06

---

(1) Income for the first quarter of 2008 includes a $13.6 million pre tax gain on the exchange of coal reserves.

(2) Loss for the second quarter of 2008 includes $245.3 million pre tax expense related to the Wheeling-Pittsburgh lawsuit (see Note 18 for further information) and a $15.3 million pre tax gain on the exchange of coal reserves.

(3) Income for the third quarter of 2008 includes $5.8 million pre tax expense related to the Wheeling-Pittsburgh lawsuit (see Note 18 for further information), $9.1 million pre tax loss on financing transaction related to fees incurred for the tender offer for our 6.625% Notes (see Note 6 for further information), $3.6 million pre tax gain on the exchange of coal reserves and other assets, and a $6.5 million pre tax loss on short-term investment reflecting an impairment of our investment in the Primary Fund (see Note 16 for further information).

(4) Income for the fourth quarter of 2008 includes $12.9 million pre tax income related to federal legislation passed that authorized refunds of black lung excise taxes paid in years that had been statutorily closed, $8.6 million pre tax gain on financing transaction from the purchase of $19.0 million of our 3.25% Notes on the open market (see Note 6 for further information), and a $22.6 million non-cash loss on the net change of derivative instruments.

(5) Income for the second quarter of 2007 includes $5.0 million non-tax deductible expense related to the settlement of a lawsuit filed by the Environmental Protection Agency (“EPA lawsuit”) and a $10.3 million pre-tax gain on the exchange of coal reserves.

(6) Income for the fourth quarter of 2007 includes $22.0 million reversal of the accrual and $11.6 million reversal of accrued interest for the Harman lawsuit (see Note 18 for further information), $15 million non-tax deductible expense related to the settlement of the EPA lawsuit, and a $6.7 million pre-tax gain on the sale of a mineral rights override.

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

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures and Changes in Internal Control Over Financial Reporting

We have established disclosure controls and procedures to ensure that information relating to us, including our consolidated subsidiaries, required to be disclosed in the reports that we file or submit under the Exchange Act, is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of the end of the period covered by this report.

Based on our evaluation as of December 31, 2008, the principal executive officer and principal financial officer have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that the information required to be disclosed in reports that we file or furnish under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2008, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control over financial reporting report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and assesses the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Massey Energy Company ("Massey") is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Massey'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.

Massey's internal control over financial reporting includes policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Massey; (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 are being made only in accordance with authorizations of management and the directors of Massey; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Massey's assets that could have a material effect on the Company's 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.

Massey's management assessed the effectiveness of Massey's internal control over financial reporting as of December 31, 2008. In making this assessment, Massey used the criteria in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment based on those criteria, Massey's management has concluded that, as of December 31, 2008, internal control over financial reporting is effective.

The effectiveness of our internal control over financial reporting as of December 31, 2008, has been audited by Ernst &

Young LLP, an independent registered public accounting firm, as stated in their report, which follows immediately hereafter.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Massey Energy Company

We have audited Massey Energy 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). Massey Energy Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the Management 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, Massey Energy Company 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 2008 consolidated financial statements of Massey Energy Company and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Richmond, Virginia
February 27, 2009

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant

Don L. Blankenship, Age 58

Mr. Blankenship has been a director since 1996. He has been Chairman and Chief Executive Officer since November 2000 and also held the position of President from November 2000 until November 2008. He has been Chairman, Chief Executive Officer and President of A.T. Massey Coal Company, Inc., our wholly owned and sole, direct operating subsidiary, since 1992. Mr. Blankenship was formerly President and Chief Operating Officer from 1990 to 1991 and President of our subsidiary, Massey Coal Services, Inc., from 1989 to 1991. He joined our subsidiary, Rawl Sales & Processing Co., in 1982. He is a director of the Center for Energy and Economic Development, the National Mining Association and the United States Chamber of Commerce.

Baxter F. Phillips, Jr., Age 62

Mr. Phillips has been a director since 2007. He has been President since November 2008. Mr. Phillips previously served as Executive Vice President and Chief Administrative Officer from November 2004 to November 2008, as Senior Vice President and Chief Financial Officer from September 2003 to November 2004 and as Vice President and Treasurer from 2000 to August 2003. Mr. Phillips joined us in 1981 and has also served in the roles of Corporate Treasurer, Manager of Export Sales and Corporate Human Resources Manager, among others.

J. Christopher Adkins, Age 45

Mr. Adkins has been Senior Vice President and Chief Operating Officer since July 2003. Mr. Adkins joined our subsidiary, Rawl Sales & Processing Co., in 1985 to work in underground mining. Since that time, he has served as section foreman, plant supervisor, President and Vice President of several subsidiaries, President of our Eagle Energy subsidiary, Director of Production of Massey Coal Services, Inc. and Vice President of Underground Production.

Mark A. Clemens, Age 42

Mr. Clemens has been Senior Vice President, Group Operations since July 2007. From January 2003 to July 2007, Mr. Clemens was President of Massey Coal Services, Inc. Mr. Clemens was formerly President of Independence Coal Company, Inc., one of our operating subsidiaries, from 2000 through December 2002 and our Corporate Controller from 1997 to 1999. Mr. Clemens has held a number of other accounting positions and has been with us since 1989.

Michael K. Snelling, Age 52

Mr. Snelling has been Vice President, Surface Operations of our subsidiary, Massey Coal Services, Inc. since June 2005. Mr. Snelling was formerly Director of Surface Mining of Massey Coal Services, Inc. from July 2003 until May 2005. Mr. Snelling joined us in 2000 and has served us in a variety of capacities, including President of our subsidiary, Nicholas Energy Co. Prior to joining us, Mr. Snelling held various positions in the coal industry including engineer, production supervisor, plant supervisor, general foreman, manager of contract mining, superintendent, mine manager and vice president of operations.

Michael D. Bauersachs, Age 44

Mr. Bauersachs has been Vice President, Planning since May 2005. Mr. Bauersachs joined us in 1998, and served as Director of Acquisitions from 1998 until 2005. Prior to joining us, Mr. Bauersachs held various positions with Zeigler Coal Holding Company and Arch Mineral Corporation.

Jeffrey M. Gillenwater, Age 44

Mr. Gillenwater has been Vice President, Human Resources since January 2009. In October 1999, Mr. Gillenwater became Director of Human Resources at our Massey Coal Services, Inc. subsidiary, and held the position of Director of External Affairs & Administration from October 2002 until January 2009. Prior to October 2002 he held the position of Human Resources Manager at several of our subsidiaries.

Richard R. Grinnan, Age 40

Mr. Grinnan has been Vice President and Corporate Secretary since May 2006. He served as Senior Corporate Counsel from July 2004 until May 2006. Prior to joining us, Mr. Grinnan was a corporate and securities attorney at the law firm of McGuireWoods LLP in Richmond, Virginia from August 2000 until July 2004.

M. Shane Harvey, Age 39

Mr. Harvey has been Vice President and General Counsel since January 2008. He served as Vice President and Assistant General Counsel from November 2006 until January 2008 and as Corporate Counsel and Senior Corporate Counsel from April 2000 until November 2006. Prior to joining us, Mr. Harvey was an attorney at the law firm of Jackson Kelly PLLC in Charleston, West Virginia from May 1994 until April 2000.

Jeffrey M. Jarosinski, Age 49

Mr. Jarosinski has been Vice President, Finance since 1998 and Chief Compliance Officer since December 2002. From 1998 through December 2002, Mr. Jarosinski was Chief Financial Officer. Mr. Jarosinski was formerly Vice President, Taxation from 1997 to 1998 and Assistant Vice President, Taxation from 1993 to 1997. Mr. Jarosinski joined us in 1988.

John M. Poma, Age 44

Mr. Poma has been Vice President and Chief Administrative Officer since January 2009. Mr. Poma previously served as Vice President, Human Resources from April 2003 to January 2009. Mr. Poma served as Corporate Counsel from 1996 until 2000 and as Senior Corporate Counsel from 2000 through March 2003. Prior to joining us in 1996, Mr. Poma was an employment attorney with the law firms of Midkiff & Hiner in Richmond, Virginia and Jenkins, Fenstermaker, Krieger, Kayes & Farrell in Huntington, West Virginia.

Steve E. Sears, Age 60

Mr. Sears has been Vice President, Sales and Marketing, and President of our subsidiary Massey Coal Sales Company, Inc. since December 2008. Mr. Sears served as President of Massey Industrial and Utility Sales, a division of Massey Coal Sales Company, Inc., from December 2006 to December 2008. Mr. Sears has held various positions within the sales department. He joined us in 1981.

Eric B. Tolbert, Age 41

Mr. Tolbert has been Vice President and Chief Financial Officer since November 2004. Mr. Tolbert served as Corporate Controller from 1999 to 2004. He joined us in 1992 as a financial analyst and subsequently served as Director of Financial Reporting. Prior to joining us, Mr. Tolbert worked for the public accounting firm Arthur Andersen from 1990 to 1992.

David W. Owings, Age 35

Mr. Owings has been Corporate Controller and principal accounting officer since November 2004. Mr. Owings previously served as Manager of Financial Reporting since joining us in 2001. Prior to joining us, Mr. Owings worked at Ernst & Young LLP, the Company's independent registered public accounting firm, serving as a manager from January 2001 through September 2001 and as a senior auditor from October 1998 through January 2001 in the Assurance and Advisory Business Services group.

The following information is incorporated by reference from our definitive proxy statement pursuant to Regulation 14A, which will be filed not later than 120 days after the close of Massey's fiscal year ended December 31, 2008:

- Information regarding the directors required by this item is found under the heading *Election of Directors*.

- Information regarding Massey's Audit Committee required by this item is found under the heading *Committees of the Board*.

- Information regarding Section 16(a) Beneficial Ownership Reporting Compliance required by this item is found under the heading *Section 16(a) Beneficial Ownership Reporting Compliance*.

- Information regarding Massey's Code of Ethics required by this item is found under the heading *Code of Ethics*.

Because Common Stock is listed on the NYSE, our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 2, 2008. In addition, we have filed, as exhibits to this annual report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Section 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Item 11. Executive Compensation

Information required by this item is included in the *Compensation Discussion and Analysis, Compensation of Named Executive Officers, Compensation Committee Interlocks and Insider Participation, and Compensation Committee Report on Executive Compensation* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2008.

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

Information required by this item is included in the *Stock Ownership of Directors and Executive Officers* and *Stock Ownership of Certain Beneficial Owners* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2008.

The following table sets forth as of December 31, 2008, the number of shares of Common Stock authorized for issuance under our equity compensation plan.

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1), (2)	(b) Weighted-average per share exercise price of outstanding options, warrants and rights (2)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders	2,612,517	$ 25.81	1,362,752
Equity compensation plans not approved by shareholders (3)	-	-	-
Total	2,612,517	$ 25.81	1,362,752

(1) There are no outstanding warrants or rights.
(2) These amounts do not include shares to be issued upon vesting of restricted stock because they have no exercise price.
(3) We do not have any equity compensation plans that have not been approved by our shareholders.

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

Information required by this item is included in the *Certain Relationships and Related Transactions* and *Director Independence* sections of the definitive proxy statement pursuant to Regulation 14A, involving the election of directors, which is incorporated herein by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2008.

Item 14. Principal Accountant Fees and Services

Information concerning principal accountant fees and services contained under the heading *The Audit Committee Report* in the definitive proxy statement pursuant to Regulation 14A, which is incorporated by reference and will be filed not later than 120 days after the close of our fiscal year ended December 31, 2008.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1.Financial Reports:

Consolidated Statements of Income for the Fiscal Years Ended December 31, 2008, 2007 and 2006

Consolidated Balance Sheets at December 31, 2008 and 2007

Consolidated Statements of Cash Flows for the Fiscal Years Ended December 31, 2008, 2007, and 2006

Consolidated Statements of Shareholders' Equity for the Fiscal Years Ended December 31, 2008, 2007, and 2006

Notes to Consolidated Financial Statements

2.Financial Statement Schedules: Except as set forth below, all schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the Consolidated Financial Statements and Notes thereto.

Schedule II—Valuation and Qualifying Accounts

3.Exhibits:

Exhibit No.	**Description**
3.1	Certificate of Ownership and Merger merging Massey Energy Company with and into Fluor Corporation accompanied by Restated Certificate of Incorporation of Massey Energy Company, as amended [filed as Exhibit 3.1 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
3.2	Restated Bylaws (as amended as of November 10, 2008) of Massey Energy Company [filed as Exhibit 3.2 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
4.1	Senior Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors and Wilmington Trust Company, as Trustee, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.2	First Supplemental Indenture, dated May 29, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 4.75% Convertible Senior Notes [filed as Exhibit 4.2 to Massey's current report on Form 8-K filed May 30, 2003 and incorporated by reference]
4.3	Indenture, dated November 10, 2003, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.625% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed November 12, 2003 and incorporated by reference]
4.4	First Supplemental Indenture, dated August 19, 2008, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.625% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed August 22, 2008 and incorporated by reference]
4.5	Second Supplemental Indenture, dated April 7, 2004, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, supplementing that certain Senior Indenture dated May 29, 2003, in connection with the Company's 2.25% Convertible Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed April 4, 2004 and incorporated by reference]
4.6	Indenture, dated as of December 21, 2005, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 6.875% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed

December 21, 2005, and incorporated by reference]

Exhibit No.	Description
4.7	Senior Indenture, dated as of August 12, 2008, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.1 to Massey's current report on Form 8-K filed August 12, 2008, and incorporated by reference]
4.8	First Supplemental Indenture, dated as of August 12, 2008, by and among Massey Energy Company, subsidiaries of Massey Energy Company, as Guarantors, and Wilmington Trust Company, as Trustee, in connection with the Company's 3.25% Senior Notes [filed as Exhibit 4.2 to Massey's current report on Form 8–K filed August 12, 2008, and incorporated by reference]
10.1	Amended and Restated Credit Agreement dated as of August 15, 2006, among A. T. Massey Coal Company, Inc. and certain of its subsidiaries, as Borrowers, Massey Energy Company and certain of its subsidiaries, as Guarantors, Bank of America, N. A., as Syndication Agent, General Electric Capital Corporation, as Documentation Agent, The CIT Group/Business Credit, Inc., as Collateral Agent, UBS Securities LLC, as Arranger, UBS AG, Stamford Branch, as Administrative Agent, and UBS Loan Finance LLC, as Swingline Lender, and the lenders party thereto [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed August 18, 2006 and incorporated by reference]
10.2	First Amendment to Amended and Restated Credit Agreement dated March 12, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed May 10, 2007 and incorporated by reference]
10.3	Limited Consent and Second Amendment to Amended and Restated Credit Agreement dated July 19, 2007 [filed as Exhibit 10.1 to Massey's quarterly report on Form 10-Q filed August 9, 2007 and incorporated by reference]
10.4	Third Amendment to Amended and Restated Credit Agreement dated March 10, 2008 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed March 14, 2008 and incorporated by reference]
10.5	Fourth Amendment to Amended and Restated Credit Agreement dated October 10, 2008 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed October 16, 2008 and incorporated by reference]
10.6	Equity Distribution Agreement dated February 3, 2009 between Massey Energy Company and UBS Securities LLC [filed as Exhibit 1.1 to Massey's current report on Form 8-K filed February 4, 2009 and incorporated by reference]
10.7	Massey Energy Company 1982 Shadow Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.8 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.8	Massey Energy Company 1988 Executive Stock Plan (as amended and restated effective November 30, 2000) [filed as Exhibit 10.6 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.9	Massey Energy Company 1996 Executive Stock Plan (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.14 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.10	Massey Energy Company 1997 Stock Appreciation Rights Plan (as amended and restated, effective November 30, 2000) [filed as Exhibit 10.9 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.11	Massey Energy Company 1999 Executive Performance Incentive Plan (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.15 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.12	Massey Energy Company 2006 Stock and Incentive Compensation Plan (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.16 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.13	Form of Non-Employee Director Initial Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.14	Form of Non-Employee Director Initial Restricted Unit Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.15	Form of Non-Employee Director Annual Restricted Stock Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.16	Form of Non-Employee Director Annual Stock Option Award Agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed February 23, 2009 and incorporated by reference]

Exhibit No.	Description
10.17	Form of stock option agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.18	Form of restricted stock agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.4 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.19	Form of restricted unit agreement under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.5 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.20	Form of cash incentive award agreement based on earnings before taxes under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.6 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.21	Form of cash incentive award agreement based on earnings before interest, taxes, deprecation and amortization under the Massey Energy Company 2006 Stock and Incentive Compensation Plan [filed as Exhibit 10.7 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]
10.22	Form of Additional Stock Option Grant Agreement [filed as Exhibit 10.3 to Massey's current report on Form 8-K filed February 23, 2009 and incorporated by reference]
10.23	A.T. Massey Coal Company, Inc. Supplemental Benefit Plan (as amended and restated as of January 1, 2009) [filed as Exhibit 10.20 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.24	Massey Executive Deferred Compensation Program (as amended and restated as of January 1, 2009) [filed as Exhibit 10.17 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.25	A.T. Massey Coal Company, Inc. Executive Deferred Compensation Plan (as amended and restated as of January 1, 2009) [filed as Exhibit 10.19 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.26	Massey Energy Company Executive Physical Program [filed as Exhibit 10.3 to Massey's annual report on Form 10-K for the fiscal year ended October 31, 2000 and incorporated by reference]
10.27	Massey Executives' Supplemental Benefit Plan (as amended and restated effective January 1, 2009) [filed as Exhibit 10.13 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.28	Massey Executives' Supplemental Benefit Plan Agreement (effective as of January 1, 2005) between Massey and Don L. Blankenship [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed January 5, 2006 and incorporated by reference]
10.29	Letter Agreement dated November 13, 2007, between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.32 to Massey's annual report on Form 10-K filed February 29, 2008 and incorporated by reference]
10.30	Letter Agreement, dated December 23, 2008, amending and restating Appendix A to the Letter Agreement, originally dated November 13, 2007, as amended and restated effective January 1, 2009, between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.11 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.31	Retention and Employment Agreement as amended and restated, effective January 1, 2009, between Massey Energy Company and John Christopher Adkins [filed as Exhibit 10.10 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.32	Employment Agreement as amended and restated, effective January 1, 2009 between Massey Energy Company and Michael K. Snelling [filed as Exhibit 10.12 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.33	Special Successor and Development Retention Program between Fluor Corporation and Don L. Blankenship dated as of September 1998 [filed as Exhibit 10.21 to Fluor's annual report on Form 10-K for the fiscal year ended October 31, 1998 and incorporated by reference]
10.34	Amendment to Special Successor and Development Retention Program between Massey (formerly Fluor Corporation) and Don L. Blankenship, effective January 1, 2009 [filed as Exhibit 10.23 to Massey's current report on Form 8-K filed December 24, 2008]
10.35	Employment and Change in Control Agreement dated November 10, 2008 between Massey Energy Company and Baxter F. Phillips, Jr. [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed November 14, 2008 and incorporated by reference]

Exhibit No.	Description
10.36	Form of Change in Control Severance Agreement for Tier 1 Participants [filed herewith]
10.37	Form of Change in Control Severance Agreement for Tier 2 Participants [filed herewith]
10.38	Form of Change in Control Severance Agreement for Tier 3 Participants [filed herewith]
10.39	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Don L. Blankenship [filed as Exhibit 10.24 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.40	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and J. Christopher Adkins [filed as Exhibit 10.25 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.41	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Eric B. Tolbert [filed as Exhibit 10.26 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.42	Change in Control Severance Agreement (as amended and restated) dated as of December 23, 2008 between Massey Energy Company and Michael K. Snelling [filed as Exhibit 10.27 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.43	Massey Energy Company 2008 Long Term Incentive Award Program as reported on Massey's current report on Form 8-K [filed November 14, 2008 and incorporated by reference]
10.44	Massey Energy Company 2009 Bonus Program as reported on Massey's current report on Form 8-K [filed November 14, 2008 and incorporated by reference]
10.45	Base salary amounts set for Massey's named executive officers as reported on Massey's current report on Form 8-K [filed November 14, 2008 and incorporated by reference]
10.46	Massey Energy Company Non-Employee Directors Compensation Summary (as amended and restated effective February 17, 2009) [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed February 23, 2009 and incorporated by reference]
10.47	Massey Energy Company Stock Plan for Non-Employee Directors (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.21 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.48	Massey Energy Company 1997 Restricted Stock Plan for Non-Employee Directors (as amended and restated, effective January 1, 2009) [filed as Exhibit 10.22 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.49	Massey Energy Company Deferred Directors' Fees Program (amended and restated, effective January 1, 2009) [filed as Exhibit 10.18 to Massey's current report on Form 8-K filed December 24, 2008 and incorporated by reference]
10.50	Distribution Agreement between Fluor Corporation and Massey Energy Company dated as of November 30, 2000 [filed as Exhibit 10.1 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
10.51	Tax Sharing Agreement between Fluor Corporation, Massey Energy Company and A.T. Massey Coal Company, Inc. dated as of November 30, 2000 [filed as Exhibit 10.2 to Massey's current report on Form 8-K filed December 15, 2000 and incorporated by this reference]
16.1	Letter from Arnett and Foster to the Securities and Exchange Commission, dated November 16, 2007 [filed as Exhibit 16.1 to Massey's current report on Form 8-K filed November 17, 2007 and incorporated by reference]
21	Massey Energy Company Subsidiaries [filed herewith]
23.1	Consent of Independent Registered Public Accounting Firm [filed herewith]
24	Manually signed Powers of Attorney executed by Massey directors [filed herewith]
31.1	Certification of Chief Executive Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
31.2	Certification of Chief Financial Officer, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [filed herewith]
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [furnished herewith]

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.

MASSEY ENERGY COMPANY

February 27, 2009

By: /s/ ERIC B. TOLBERT

Eric B. Tolbert,
Vice President and Chief Financial Officer

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
Principal Executive Officer and Director:		
/s/ DON L. BLANKENSHIP **Don L. Blankenship**	Chairman and Chief Executive Officer	February 27, 2009
Principal Financial Officer:		
/s/ ERIC B. TOLBERT **Eric B. Tolbert**	Vice President and Chief Financial Officer	February 27, 2009
Principal Accounting Officer:		
/s/ DAVID W. OWINGS **David W. Owings**	Controller	February 27, 2009
Other Directors:		
* **James B. Crawford**	Director	February 27, 2009
* **Robert H. Foglesong**	Director	February 27, 2009
* **Richard M. Gabrys**	Director	February 27, 2009
* **E. Gordon Gee**	Director	February 27, 2009
* **Bobby R. Inman**	Director	February 27, 2009
* **Lady Judge**	Director	February 27, 2009
* **Dan R. Moore**	Director	February 27, 2009
* **Baxter F. Phillips, Jr.**	Director and President	February 27, 2009
* **Stanley C. Suboleski**	Director	February 27, 2009

By: /s/ RICHARD R. GRINNAN February 27, 2009

Richard R. Grinnan
Attorney-in-fact

---

* Manually signed Powers of Attorney authorizing Eric B. Tolbert., Richard R. Grinnan and Jeffrey M. Jarosinski, and each of them, to sign the annual report on Form 10-K for the fiscal year ended December 31, 2008 and any amendments thereto as attorneys-in-fact for certain directors and officers of the registrant are included herein as Exhibits 24.

MASSEY ENERGY COMPANY

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
(In Thousands)

Description	Balance at Beginning of Period	Amounts Charged to Costs and Expenses	Deductions (1)	Other	Balance at End of Period
YEAR ENDED DECEMBER 31, 2008					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 444	$ 429	$ -	$ -	$ 873
YEAR ENDED DECEMBER 31, 2007					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 576	$ (132)	$ -	$ -	$ 444
YEAR ENDED DECEMBER 31, 2006					
Reserves deducted from asset accounts:					
Allowance for accounts and notes receivable	$ 2,063	$ 12	$ (1,499)	$ -	$ 576

(1) Reserves utilized, unless otherwise indicated.