CONSOL ENERGY INC
Form 10-K
February 19, 2008
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007;

OR

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

For the transition period from __________

Commission file number: 001-14901

CONSOL ENERGY INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0337383**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

Consol Plaza

1800 Washington Road

Pittsburgh, Pennsylvania 15241

(Address of principal executive offices including zip code)

Registrant s telephone number including area code: 412-831-4000

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

Title of each class	**Name of exchange on which registered**
Common Stock ($.01 par value)	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x 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 x

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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 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 or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of voting stock held by nonaffiliates of the registrant as of June 29, 2007, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price of the common stock on the New York Stock Exchange on such date was $8,406,925,288.

The number of shares outstanding of the registrant s common stock as of January 31, 2008 is 182,502,996 shares.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Consol Energy s Proxy Statement for the Annual Meeting of Shareholders to be held on April 29, 2008,

are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III.

TABLE OF CONTENTS

Table of Contents

FORWARD-LOOKING STATEMENTS

Various statements in this document, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements (as defined in Section 21E of the Securities Exchange Act of 1934). The forward-looking statements may include projections and estimates concerning the timing and success of specific projects and our future production, revenues, income and capital spending. When we use the words believe, intend, expect, may, should, anticipate, could, would, will, estim project, or their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The forward-looking statements in this document speak only as of the date of this document; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. We have based these forward-looking statements on our current expectations and assumptions about future events. These risks, uncertainties and contingencies include, but are not limited to, the following:

- an extended decline in prices we receive for our coal and gas affecting our operating results and cash flows;
- reliance on customers extending existing contracts or entering into new long-term contracts for coal;
- reliance on major customers;
- our inability to collect payments from customers if their creditworthiness declines;
- the disruption of rail, barge and other systems that deliver our coal;
- a loss of our competitive position because of the competitive nature of the coal industry and the gas industry, or a loss of our competitive position because of overcapacity in these industries impairing our profitability;
- our inability to hire qualified people to meet replacement or expansion needs;
- coal users switching to other fuels in order to comply with various environmental standards related to coal combustion;
- the inability to produce a sufficient amount of coal to fulfill our customers requirements which could result in our customers initiating claims against us;
- increases in the price of commodities used in our mining operations could impact our cost of production;
- foreign currency fluctuations could adversely affect the competitiveness of our coal abroad;
- the risks inherent in coal mining being subject to unexpected disruptions, including geological conditions, equipment failure, timing of completion of significant construction or repair of equipment, fires, accidents and weather conditions which could cause our results to deteriorate;

increases in the price of commodities used in our mining operations could impact our cost of production;

obtaining governmental permits and approvals for our operations;

the effects of proposals to regulate greenhouse gas emissions;

the effects of government regulation;

the effects of stringent federal and state employee health and safety regulations;

the effects of mine closing, reclamation and certain other liabilities;

uncertainties in estimating our economically recoverable coal and gas reserves;

Table of Contents

we do not insure against all potential operating risks;

the outcomes of various legal proceedings, which proceedings are more fully described in our reports filed under the Securities Exchange Act of 1934;

increased exposure to employee related long-term liabilities;

our participation in multi-employer pension plans may expose us to obligations beyond the obligation to our employees;

lump sum payments made to retiring salaried employees pursuant to our defined benefit pension plan;

our ability to comply with laws or regulations requiring that we obtain surety bonds for workers compensation and other statutory requirements;

acquisitions that we recently have made or may make in the future including the accuracy of our assessment of the acquired businesses and their risks, achieving any anticipated synergies, integrating the acquisitions and unanticipated changes that could affect assumptions we may have made;

the anti-takeover effects of our rights plan could prevent a change of control;

risks in exploring for and producing gas;

new gas development projects and exploration for gas in areas where we have little or no proven gas reserves;

the disruption of pipeline systems which deliver our gas;

the availability of field services, equipment and personnel for drilling and producing gas;

replacing our natural gas reserves which if not replaced will cause our gas reserves and gas production to decline;

costs associated with perfecting title for gas rights in some of our properties;

location of a vast majority of our gas producing properties in three counties in southwestern Virginia, making us vulnerable to risks associated with having our gas production concentrated in one area;

other persons could have ownership rights in our advanced gas extraction techniques which could force us to cease using those techniques or pay royalties;

the coalbeds and other strata from which we produce methane gas frequently contain water and the gas often contains impurities that may hamper production;

our hedging activities may prevent us from benefiting from price increases and may expose us to other risks;

other factors discussed in our 2007 Form 10-K under Risk Factors, as updated by any subsequent Form 10-Qs, which are on file at the Securities and Exchange Commission.

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.

Item 1. ***Business*.**

CONSOL Energy s History

We are a multi-fuel energy producer and energy services provider primarily serving the electric power generation industry in the United States. That industry generates approximately two-thirds of its output by burning coal or gas, the two fuels we produce. During the year ended December 31, 2007, we produced high-Btu bituminous coal from 17 mining complexes in the United States, including a fully consolidated, 49% owned,

Table of Contents

variable interest entity, and a 49% equity affiliate. Coal produced from our mines has a high-Btu content which creates more energy per unit when burned compared to coals with lower Btu content. As a result, coals with greater Btu content can be more efficient to use. We are the majority shareholder (81.7%) of CNX Gas Corporation (CNX Gas). On January 29, 2008, we announced our intention to offer to acquire all of the shares of CNX Gas which we currently do not own. CNX Gas primarily produces pipeline-quality coalbed methane gas from our coal properties in the Northern and the Central Appalachian basin, and other western basins and oil and gas from properties in the Appalachian and Illinois Basins. We believe that the use of coal and gas to generate electricity will grow as demand for power increases.

Historically, we rank among the largest coal producers in the United States based upon total revenue, net income and operating cash flow. Our production of approximately 65 million tons of coal in 2007 accounted for approximately 6% of the total tons produced in the United States and approximately 13% of the total tons produced east of the Mississippi River during 2007. We are one of the premier coal producers in the United States by several measures:

- We mine more high-Btu bituminous coal than any other United States producer;
- We are the largest coal producer east of the Mississippi River;
- We have the second largest amount of recoverable coal reserves among United States coal producers; and
- We are the largest United States producer of coal from underground mines.

CNX Gas also ranks as one of the largest coalbed methane gas companies in the United States based on both their proved reserves and their current daily production. Our position as a gas producer is highlighted by several measures:

- Our principal coalbed methane operations produce gas from coal seams (single layers or stratum of coal) with a high gas content;
- We had approximately 155 million cubic feet of net average daily production for the month of December 2007;
- At December 31, 2007, we had 2,989 net producing wells connected by approximately 1,301 miles of gathering lines and associated infrastructure; and
- We controlled one of the largest coalbed methane reserve bases among publicly traded oil and gas companies in the United States with approximately 1.3 trillion cubic feet of net proved reserves of gas at December 31, 2007.

Additionally, we provide energy services, including river and dock services, terminal services, industrial supply services, coal waste disposal services and land resource services.

CONSOL Energy was organized as a Delaware corporation in 1991. We use CONSOL Energy to refer to CONSOL Energy Inc. and our subsidiaries, unless the context otherwise requires.

Industry Segments

CONSOL Energy has two principal business units: Coal and Gas. The principal activities of the Coal unit are mining, preparation and marketing of steam coal, sold primarily to power generators, and metallurgical coal, sold to metal and coke producers. The Coal unit includes four reportable segments. These reportable segments are Northern Appalachian, Central Appalachian, Metallurgical and Other Coal. Each of these reportable segments includes a number of operating segments (mines). For the year ended December 31, 2007, the Northern Appalachian aggregated segment includes the following mines: Blacksville #2, Robinson Run, McElroy, Loveridge, Bailey, Enlow Fork, Mine 84 and Mahoning Valley. For the year ended December 31, 2007, the Central Appalachian aggregated segment includes the following mines: Jones Fork, Mill Creek and Wiley-Mill

Creek. It also includes the following mines acquired with the AMVEST Corporation and certain of its subsidiaries and affiliates (AMVEST) acquisition: Fola Complex and the Terry Eagle Complex. For the year ended December 31, 2007, the Metallurgical aggregated segment includes the following mines: Buchanan and Amonate. The Other Coal segment includes our purchased coal activities, idled mine cost, coal segment business units not meeting aggregation criteria, as well as various other activities assigned to the coal segment but not allocated to each individual mine. The principal activity of the Gas unit is to produce pipeline-quality methane gas for sale primarily to gas wholesalers. CONSOL Energy s All Other segment includes terminal services, river and dock services, industrial supply services and other business activities, including rentals of building and flight operations. Financial information concerning industry segments, as defined by accounting principles generally accepted in the United States, for the years ended December 31, 2007, 2006 and 2005 is included in Note 27 of Notes to Audited Consolidated Financial Statements included as Item 8 in Part II of this Annual Report on Form 10-K.

Coal Operations

Mining Complexes

During the year ended December 31, 2007, CONSOL Energy had 17 active mining complexes, including a fully consolidated, 49% owned, variable interest entity, and a 49% equity affiliate, all located in the United States.

The following map provides the location of CONSOL Energy s operations by region:

Table of Contents

The following table provides the location of CONSOL Energy s mining complexes and the coal reserves associated with each.

CONSOL ENERGY MINING COMPLEXES

Proven and Probable Assigned and Accessible Coal Reserves as of December 31, 2007 and 2006

Mine/Reserve	Location	Reserve Class	Coal Seam	Average Seam Thickness (feet)	As Received Heat Value(1) (Btu/lb) Typical	Range		Owned (%)	Recoverable Reserves(2) Leased (%)	Tons in Millions 12/31/2007	Recoverable Reserves (tons in Millions) 12/31/2006
ASSIGNED OPERATING											
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)											
Enlow Fork	Enon, PA	Assigned	Pittsburgh	5.3	12,940	12,860	13,060	97%	3%	171.2	182.4
		Accessible	Pittsburgh	5.4	12,900	12,830	13,000	75%	25%	185.3	185.1
Bailey	Enon, PA	Assigned	Pittsburgh	5.7	12,950	12,860	13,060	21%	79%	43.4	53.2
		Accessible	Pittsburgh	5.7	12,900	12,830	13,000	44%	56%	144.2	144.2
Mine 84	Eighty Four, PA	Assigned	Pittsburgh	5.6	13,120	12,950	13,250	48%	52%	28.7	32.3
		Accessible	Pittsburgh	5.4	13,050	12,880	13,180	91%	9%	86.7	86.7
McElroy	Glen Easton, WV	Assigned	Pittsburgh	5.9	12,570	12,450	12,650	100%	%	211.1	197.8
		Accessible	Pittsburgh	5.8	12,530	12,410	12,610	99%	1%	69.0	68.8
Loveridge	Fairview, WV	Assigned	Pittsburgh	7.7	13,150	13,070	13,370	97%	3%	22.3	28.9
		Accessible	Pittsburgh	7.5	13,100	13,020	13,320	89%	11%	61.6	61.6
Robinson Run	Shinnston, WV	Assigned	Pittsburgh	7.6	12,940	12,600	13,300	66%	34%	12.2	15.4
		Accessible	Pittsburgh	6.9	12,940	12,600	13,300	74%	26%	219.9	206.2
Blacksville 2	Wana, WV	Assigned	Pittsburgh	6.6	13,060	12,850	13,250	100%	%	5.7	10.9
		Accessible	Pittsburgh	6.8	13,100	12,890	13,290	98%	2%	55.7	55.7
Harrison Resources(4)	Cadiz, OH	Assigned	Multiple	4.3	11,570	11,350	11,850	100%	%	9.8	
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)											
Buchanan	Mavisdale, VA	Assigned	Pocahontas 3	5.7	13,980	13,700	14,200	13%	87%	47.1	49.9
		Accessible	Pocahontas 3	6.1	13,930	13,650	14,150	12%	88%	64.4	64.4
AMVEST Fola Complex	Bickmore, WV	Assigned	Multiple	5.9	12,380	12,250	12,550	95%	5%	107.8	
AMVEST Terry Eagle Complex	Bickmore, WV	Assigned	Multiple	3.2	13,300	13,200	13,350	%	100%	23.2	
Mill Creek Complex	Deane, KY	Assigned	Multiple	3.7	12,430	12,350	12,650	90%	10%	11.6	12.5
		Accessible	Multiple	4.4	11,380	11,300	11,600	100%	%	0.7	0.7
Jones Fork Complex	Mousie, KY	Assigned	Multiple	3.2	12,530	12,450	12,650	75%	25%	37.7	31.1
		Accessible	Multiple	2.8	12,330	12,250	12,450	88%	12%	1.7	3.5
Amonate Complex	Amonate, VA	Assigned	Multiple	3.8	13,100	12,850	13,350	72%	28%	21.9	22.9
Miller Creek Complex	Delbarton, WV	Assigned	Multiple	8.9	12,000	11,600	12,650	%	100%	6.5	7.5
Southern West Virginia Energy(3)	Mingo County, WV	Assigned	Multiple	8.1	12,100	11,600	12,650	%	100%	7.3	8.1
		Accessible	Multiple	7.1	11,900	11,600	12,650	%	100%	9.1	9.1
Western U.S. (Utah)											
Emery	Emery Co., UT	Assigned	Ferron I	7.5	12,260	12,000	13,000	81%	19%	18.0	19.0
Total Assigned Operating and Accessible										1,683.8	1,557.9

Table of Contents

(1) The heat value shown for assigned reserves is based on the quality of coal mined and processed during the year ended December 31, 2007. The heat value shown for accessible reserves is based on the same mining and processing methods as for the assigned reserves with adjustments made based on the variability found in exploration drill core samples. The heat values given have been adjusted to include moisture that may be added during mining or processing and for dilution by rock lying above or below the coal seam.

(2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustments for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam. Reserves are reported only for those coal seams that are controlled by ownership or leases.

(3) Southern West Virginia Energy (SWVE) is a variable interest entity as defined by Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51, in which CONSOL Energy acquired a 49% ownership interest in 2005. Accordingly, reserve tonnage reflects 100% of SWVE.

(4) Harrison Resources is an equity affiliate in which CONSOL Energy owns a 49% interest. Reserves reported equal CONSOL Energy s 49% proportionate interest in Harrison Resources reserves.

Excluded from the table above are approximately 248.9 million tons of reserves at December 31, 2007 that are assigned to projects that have not produced coal in 2007 or 2006. These assigned reserves are in the Northern Appalachia (northern West Virginia), Central Appalachia (Virginia and eastern Kentucky) and Illinois Basin (Illinois) regions. These reserves are approximately 74% owned and 26% leased.

CONSOL Energy assigns coal reserves to each of our mining complexes. The amount of coal we assign to a mining complex generally is sufficient to support mining through the duration of our current mining permit. Under federal law, we must renew our mining permits every five years. All assigned reserves have their required permits or governmental approvals, or there is a high probability that these approvals will be secured.

In addition, our mining complexes may have access to additional reserves that have not yet been assigned. We refer to these reserves as accessible. Accessible reserves are proven and probable unassigned reserves that can be accessed by an existing mining complex, utilizing the existing infrastructure of the complex to mine and to process the coal in this area. Mining an accessible reserve does not require additional capital spending beyond that required to extend or to continue the normal progression of the mine, such as the sinking of airshafts or the construction of portal facilities.

Some reserves may be accessible by more than one mining complex because of the proximity of many of our mining complexes to one another. In the table above, the accessible reserves indicated for a mining complex are based on our review of current mining plans and reflects our best judgment as to which mining complex is most likely to utilize the reserve.

Assigned and unassigned coal reserves are proven and probable reserves which are either owned or leased. The leases have terms extending up to 30 years and generally provide for renewal through the anticipated life of the associated mine. These renewals are exercisable by the payment of minimum royalties. Under current mining plans, assigned reserves reported will be mined out within the period of existing leases or within the time period of probable lease renewal periods.

Coal Reserves

At December 31, 2007, CONSOL Energy had an estimated 4.5 billion tons of proven and probable reserves. Reserves are the portion of the proven and probable tonnage that meet CONSOL Energy s economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels.

Reserves are defined in Securities and Exchange Commission (SEC) Industry Guide 7 as follows:

Proven (Measured) Reserves Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed

Table of Contents

sampling and (b) the sites for inspection, sampling and measurement are spaced so close and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

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

Spacing of points of observation for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). Our estimates for proven reserves have the highest degree of geologic assurance. Estimates for proven reserves are based on points of observation that are equal to or less than 0.5 mile apart. Estimates for probable reserves have a moderate degree of geologic assurance and are computed from points of observation that are between 0.5 to 1.5 miles apart.

An exception is made concerning spacing of observation points with respect to our Pittsburgh coal seam reserves. Because of the well-known continuity of this seam, spacing requirements are 3,000 feet or less for proven reserves and between 3,000 and 8,000 feet for probable reserves.

CONSOL Energy s estimates of proven and probable reserves do not rely on isolated points of observation. Small pods of reserves based on a single observation point are not considered; continuity between observation points over a large area is necessary for proven or probable reserves.

Our reserve estimates are predicated on information obtained from our ongoing exploration drilling and in-mine sampling programs. Data including coal seam elevation, thickness, and, where samples are available, coal quality is entered into a computerized geological database. This information is then combined with data on ownership or control of the mineral and surface interests to determine the extent of reserves in a given area. Reserve estimates include mine recovery rates that reflect CONSOL Energy s experience in various types of underground and surface coal mines.

CONSOL Energy s reserve estimates are based on geological, engineering and market data assembled and analyzed by our staff of geologists and engineers located at individual mines, operations offices and at our principal office. The reserve estimates are reviewed and adjusted annually to reflect production of coal from reserves, analysis of new engineering and geological data, changes in property control, modification of mining methods and other factors. Information, including the quantity and quality of reserves, coal and surface control, and other information relating to CONSOL Energy s coal reserve and land holdings, is maintained through a system of interrelated computerized databases.

Our estimate of proven and probable coal reserves has been determined by CONSOL Energy s geologists and mining engineers. Approximately 95% of the amounts included in our 2007 coal reserves have been reviewed and confirmed by an independent third party consultant. The independent consultant reviewed the procedures used by us to prepare our internal estimate, verified the accuracy of selected property reserve estimates and retabulated reserve groups according to standard classifications of reliability.

CONSOL Energy s proven and probable coal reserves fall within the range of commercially marketed coals in the United States. The marketability of coal depends on its value-in-use for a particular application, and this is affected by coal quality, such as, sulfur content, ash and heating value. Modern power plant boiler design aspects can compensate for coal quality differences that occur. Therefore, any of CONSOL Energy s coals can be marketed for power generation.

CONSOL Energy s reserves are located in northern Appalachia (63%), central Appalachia (13%), the mid-western United States (18%), the western United States (4%), and in western Canada (2%) at December 31, 2007.

Table of Contents

The following table sets forth our unassigned proven and probable reserves by region:

CONSOL Energy UNASSIGNED Recoverable Coal Reserves as of 12/31/07

Coal Producing Region	As Received Heat Value(1) (Btu/lb)		Recoverable Reserves 12/31/07(2) Owned (%)	Leased (%)	Tons (in millions)	Recoverable Reserves (tons in millions) 12/31/2006
Northern Appalachia (Pennsylvania, Ohio, Northern West Virginia)	11,400	13,500	77%	23%	1,331.8	1,233.5
Central Appalachia (Virginia, Southern West Virginia, Eastern Kentucky)	11,900	14,200	54%	46%	233.9	176.5
Illinois Basin (Illinois, Western Kentucky, Indiana)	11,500	11,900	43%	57%	780.6	697.5
Western U.S. (Wyoming)		9,400	100%	%	169.1	252.7
Western Canada (Alberta)	12,400	12,900	%	100%	77.9	129.1
Total			**64%**	**36%**	**2,593.3**	**2,489.3**

1) The heat value estimates for Northern Appalachian and Central Appalachian Unassigned coal reserves include adjustments for moisture that may be added during mining or processing as well as for dilution by rock lying above or below the coal seam. The mining and processing methods currently in use are used for these estimates. The heat value estimates for the Illinois Basin, Western U.S. and Western Canada Unassigned reserves are based primarily on exploration drill core data that may not include adjustments for moisture added during mining or processing, or for dilution by rock lying above or below the coal seam.
2) Recoverable reserves are calculated based on the area in which mineable coal exists, coal seam thickness, and average density determined by laboratory testing of drill core samples. This calculation is adjusted to account for coal that will not be recovered during mining and for losses that occur if the coal is processed after mining. Reserve calculations do not include adjustment for moisture that may be added during mining or processing, nor do the calculations include adjustments for dilution from rock lying above or below the coal seam.

The following table summarizes our proven and probable reserves as of December 31, 2007 by region and type of coal or sulfur content (sulfur content per million British thermal units). Proven and probable reserves include both assigned and unassigned reserves. The table classifies bituminous coal as high volatile A, B and C. High volatile A, B and C bituminous coals are classified on the basis of heat value. The table also classifies bituminous coals as medium and low volatile which are classified on the basis of fixed carbon and volatile matter. Coal is ranked by the degree of alteration it has undergone since the initial deposition of the organic material. The lowest ranked coal, lignite, has undergone less transformation than the highest ranked coal, anthracite. From the lowest to the highest rank, the coals are: lignite; sub-bituminous; bituminous and anthracite. The ranking is determined by measuring the fixed carbon to volatile matter ratio and the heat content of the coal. As rank increases, the amount of fixed carbon increases, volatile matter decreases, and heat content increases. Bituminous coals are further characterized by the amount of volatile matter present. Bituminous coals with high volatile matter content are also ranked. High volatile A bituminous coals have higher heat content than high volatile C bituminous coals. These characterizations of coal allow a user to predict the behavior of a coal when burned in a boiler to produce heat or when it is heated in the absence of oxygen to produce coke for steel production.

Table of Contents

CONSOL ENERGY PROVEN AND PROBABLE RECOVERABLE COAL RESERVES

BY PRODUCING REGION AND PRODUCT (IN MILLIONS OF TONS) AS OF DECEMBER 31, 2007

	≤1.20 lbs S02/MMBtu			> 1.20 ≤ 2.50 lbs S02/MMBtu			> 2.50 lbs S02/MMBtu				
By Region	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Total**	**Percentage By Region**
Northern Appalachia:											
Metallurgical:											
High Vol A Bituminous						162.3				162.3	3.6%
Steam:											
High Vol A Bituminous						137.7	57.6	134.2	2,304.4	2,633.9	58.2%
Low Vol Bituminous						33.6				33.6	0.7%
Region Total						333.6	57.6	134.2	2,304.4	2,829.8	62.5%
Central Appalachia:											
Metallurgical:											
High Vol A Bituminous		4.9	31.3			20.6				56.8	1.3%
Med Vol Bituminous	1.0	0.9	64.3			12.7				78.9	1.7%
Low Vol Bituminous			130.6	2.3						132.9	2.9%
Steam:											
High Vol A Bituminous	34.2	75.1	14.2	70.5	45.8	89.5	0.4	1.7	11.2	342.6	7.6%
Region Total	35.2	80.9	240.4	72.8	45.8	122.8	0.4	1.7	11.2	611.2	13.5%
Midwest Illinois Basin:											
Steam:											
High Vol B Bituminous					79.3			460.6		539.9	11.9%
High Vol C Bituminous					159.5		108.4			267.9	5.9%
Region Total					238.8		108.4	460.6		807.8	17.8%
Northern Powder River Basin:											
Steam:											
Subbituminous B			169.1							169.1	3.7%
Region Total			169.1							169.1	3.7%
Utah Emery Field:											
High Vol B Bituminous					30.3					30.3	0.7%
Region Total					30.3					30.3	0.7%
Western Canada:											
Metallurgical:											
Med Vol Bituminous	30.1	47.7								77.8	1.8%
Region Total	30.1	47.7								77.8	1.8%
Total Company	65.3	128.6	409.5	72.8	314.9	456.4	166.4	596.5	2,315.6	4,526.0	100.0%
Percent of Total	1.4%	2.8%	9.0%	1.6%	7.0%	10.1%	3.7%	13.2%	51.2%	100.0%	

11

Table of Contents

CONSOL ENERGY PROVEN AND PROBABLE RECOVERABLE COAL RESERVES BY PRODUCT

(MILLIONS OF TONS) AS OF DECEMBER 31, 2007

The following table classifies bituminous coal as high volatile A, B and C. High volatile A, B and C bituminous coals are classified on the basis of heat value. The table also classifies bituminous coals as medium and low volatile which are classified on the basis of fixed carbon and volatile matter.

	≤1.20 lbs S02/MMBtu			> 1.20 ≤ 2.50 lbs S02/MMBtu			> 2.50 lbs S02/MMBtu				
By Product	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Low Btu**	**Med Btu**	**High Btu**	**Total**	**Percentage By Product**
Metallurgical:											
High Vol A Bituminous		4.9	31.3			182.9				219.1	4.8%
Med Vol Bituminous	31.1	48.6	64.3			12.7				156.7	3.5%
Low Vol Bituminous			130.6	2.3						132.9	2.9%
Total Metallurgical	31.1	53.5	226.2	2.3		195.6				508.7	11.2%
Steam:											
High Vol A Bituminous	34.2	75.1	14.2	70.5	45.8	227.2	58.0	135.9	2,315.6	2,976.5	65.8%
High Vol B Bituminous					109.6			460.6		570.2	12.6%
High Vol C Bituminous					159.5		108.4			267.9	5.9%
Low Vol Bituminous						33.6				33.6	0.7%
Subbituminous B			169.1							169.1	3.8%
Total Steam	34.2	75.1	183.3	70.5	314.9	260.8	166.4	596.5	2,315.6	4,017.3	88.8%
Total	65.3	128.6	409.5	72.8	314.9	456.4	166.4	596.5	2,315.6	4,526.0	100.0%
Percent of Total	1.4%	2.8%	9.0%	1.6%	7.0%	10.1%	3.7%	13.2%	51.2%	100.0%	

The following table categorizes the relative Btu values (low, medium and high) for each of CONSOL Energy s producing regions in Btu s per pound of coal.

Region	**Low**	**Medium**	**High**
Northern, Central Appalachia and Canada	< 12,500	12,500 13,000	> 13,000
Midwest Appalachia	< 11,600	11,600 12,000	> 12,000
Northern Powder River Basin	< 8,400	8,400 8,800	> 8,800
Colorado and Utah	< 11,000	11,000 12,000	> 12,000

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 and indicates that when burned, the coal will produce emissions that will meet the current standard without further cleanup. A coal 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, a compliance coal will meet the power plant emission standard of 1.2 pounds of sulfur dioxide per million British thermal units of fuel consumed. At December 31, 2007, 0.6 billion tons, or 13 %, of our coal reserves met the current standard as a compliance coal. However, in March 2005 the U.S. Environmental Protection Agency promulgated new regulations that further restrict emissions. It is possible that no coal will be considered compliance coal with emission standards restricted to a level that requires emissions-control technology to be used regardless of the sulfur content of the coal. Our customers have responded to these new standards in many cases by retrofitting flue gas desulfurization systems (scrubbers) to many of their existing power plants. Because these systems remove sulfur dioxide before it is emitted into the atmosphere, our customers are less concerned about the sulfur content of our coal.

Table of Contents

As a result of a 1998 court decision forcing the establishment of mercury emissions standards for power plants, the Environmental Protection Agency also promulgated a regulatory program for controlling mercury. CONSOL Energy coals have mercury contents typical for their rank and location (approximately 0.07-0.15 parts mercury per million British thermal unit). Because most CONSOL Energy coals have high heating values, they have lower mercury contents (on a pound per British thermal unit basis) than lower rank coals at a given mercury concentration. Eastern bituminous coals tend to produce a greater proportion of flue gas mercury in the ionic or oxidized form (which is captured by scrubbers installed for sulfur control) than sub-bituminous coal, including coals produced in the Powder River Basin. High rank coals also may be more amenable to other methods of controlling mercury emissions, such as by carbon injection. In the case of mercury, the determination of the existence of a compliance coal for mercury will be based on an analysis of the requirements of the new program and may result in a coal that is compliant for sulfur dioxide standards, but non-compliant for mercury. The first phase of the new federal standards for mercury emissions must be met beginning in 2010. Some states have adopted a similar control program for mercury but with more strict limits and a shorter time frame for compliance.

Production

In the year ended December 31, 2007, 96% of CONSOL Energy s production came from underground mines and 4% from surface mines. Where the geology is favorable and reserves are sufficient, CONSOL Energy employs longwall mining systems in our underground mines. For the year ended December 31, 2007, 88% of our production came from mines equipped with longwall mining systems. Underground longwall systems are highly mechanized, capital intensive operations. Mines using longwall systems have a low variable cost structure compared with other types of mines and can achieve high productivity levels compared with those of other underground mining methods. Because CONSOL Energy has substantial reserves readily suitable to these operations, CONSOL Energy believes that these longwall mines can increase capacity at low incremental cost.

Table of Contents

The following table shows the production, in millions of tons, for CONSOL Energy s mines in the year ended December 31, 2007, 2006 and 2005, the location of each mine, the type of mine, the type of equipment used at each mine and the year each mine was established or acquired by us.

Mine	Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in millions) 2007	2006	2005	Year Established or Acquired
Northern Appalachia								
Enlow Fork	Enon, Pennsylvania	U	LW/CM	R R/B	11.2	10.7	9.8	1990
Bailey	Enon, Pennsylvania	U	LW/CM	R R/B	9.9	10.2	11.1	1984
McElroy	Glen Easton, West Virginia	U	LW/CM	B	9.7	10.5	10.4	1968
Loveridge	Fairview, West Virginia	U	LW/CM	R T	6.6	6.4	6.4	1956
Robinson Run	Shinnston, West Virginia	U	LW/CM	R CB	6.5	5.7	6.1	1966
Blacksville 2	Wana, West Virginia	U	LW/CM	R R/B T	5.1	5.0	5.3	1970
Mine No. 84	Eighty Four, Pennsylvania	U	LW/CM	R R/B T	3.6	3.5	3.8	1998
Harrison Resource Corporation(1)(6)	Cadiz, Ohio	S	S/L	R T	0.1			2007
Shoemaker	Moundsville, West Virginia	U	LW/CM	B		1.0	3.5	1966
Mahoning Valley	Cadiz, Ohio	S	S/L	R T		0.2	0.6	1979
Central Appalachia								
Jones Fork(1)(3)	Mousie, Kentucky	U/S	CM	R T	3.1	3.1	2.9	1992
Buchanan(4)	Mavisdale, Virginia	U	LW/CM	R	2.8	5.0	1.7	1983
AMVEST-Fola Complex(1)(2)(3)	Bickmore, West Virginia	U/S	A S/L CM	R	1.8			2007
Mill Creek(1)	Deane, Kentucky	U/S	CM	R	1.1	2.1	2.8	1994
Southern West Virginia Resources(1)(3)(5)	Mingo County, West Virginia	U/S	CM/S/L	T R	0.8	1.2	0.5	2005
Miller Creek Complex(1)(3)	Delbarton, West Virginia	U/S	CM/S/L	T	0.6	0.9	1.2	2004
Amonate(1)	Amonate, Virginia	U/S	CM/S/L	R T	0.6	0.5	0.6	1925
VP-8(7)	Rowe, Virginia	U	LW/CM	R		0.3	1.2	1993
AMVEST-Terry Eagle Complex(2)	Jodie, West Virginia	U/S	CM A S/L	R T	0.1			2007
Western U.S.								
Emery	Emery County, Utah	U	CM	T	1.0	1.1	1.2	1945

A= Auger

S = Surface

U = Underground

LW = Longwall

CM = Continuous Miner

S/L = Stripping Shovel and Front End Loaders

R = Rail

B = Barge

R/B = Rail to Barge

T = Truck

CB = Conveyor Belt

(1) Harrison Resources, Amonate, Mill Creek, Miller Creek, Jones Fork, AMVEST-Fola Complex and Southern West Virginia Resources complexes include facilities operated by independent mining contractors.
(2) Mine Acquired in AMVEST Corporation acquisition on July 31, 2007.

(3) Mine was idled for part of the year ended December 31, 2007 due to market conditions.
(4) Buchanan Mine was idled for part of the year ended December 31, 2007 after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine.
(5) The amounts shown for Southern West Virginia Energy (SWVE) represent 100% of SWVE production for the period the entity was a variable interest entity as defined by Financial Accounting Standards Board Interpretation No. 46(R), Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51. CONSOL Energy acquired a 49% ownership interest in 2005.
(6) Production amounts represent CONSOL Energy s 49% ownership interest.
(7) Mine was idled due to depletion of economic coal reserves.

Table of Contents

Our sales of bituminous coal were at an average sales price per ton produced as follows:

	Years Ended December 31,		
	2007	2006	2005
Average Sales Price Per Ton Produced	$ 40.60	$ 38.99	$ 35.61

Construction of the new slope and overland belt at Robinson Run was completed and placed in service in 2007. This project provides for increased belt availability at the mine and has contributed to record production in 2007. Also, two major construction projects continued during 2007 at the Bailey Mine and Shoemaker Mine. The Bailey Mine s new slope construction was ongoing, and the overland belt earthwork commenced in July 2007. Both the slope and overland belt construction are projected to be completed late in the first quarter of 2009. The Shoemaker Mine s underground belt haulage project construction continued, and the new slope construction started in September 2007. This project is to be completed during the first quarter of 2010, subject to market conditions, allowing Shoemaker Mine to resume production. Both of these projects will provide for increased mine production through belt availability and cost improvements. These projects also enhance safety by allowing old areas of the mine to be sealed. Mines setting production records for the year ended December 31, 2007 were Enlow Fork Mine (11.2 million tons), Loveridge Mine (6.6 million tons) and Robinson Run Mine (6.5 million tons).

In July 2007, production at the Buchanan Mine was suspended after several roof falls in previously mined areas damaged some of the ventilation controls inside the mine, requiring a general evacuation of the mine by employees. The mine atmosphere was continually monitored to determine the impact of the roof falls on the mine s ventilation system and the overall mine atmosphere. Two mine atmosphere monitoring stations showed levels of carbon monoxide above ambient levels for several months after the roof falls damaged the ventilation controls. Efforts to eliminate carbon monoxide in the mine were narrowed to an underground area about 400 feet in diameter into which the company pumped inert gas through a number of bore holes that had been drilled. The underground area of the Buchanan Mine encompasses about five square miles. In compliance with safety agency requirements, the mine was temporarily sealed in late November as a final step before reentry into the mine. On January 20, 2008, the restart of the fans was approved by the Commonwealth of Virginia Department of Mines, Minerals and Energy, and by the federal Mine Safety and Health Administration. The temporary mine seals were removed and the ventilation fans were restarted. Specially trained mine rescue teams re-entered the mine on January 28, 2008 and are in the process of evaluating the extent of damage to the mine s ventilation system and making temporary repairs.

Title to coal properties that we lease or purchase and the boundaries of these properties are verified at the time we lease or acquire the properties by law firms retained by us. Consistent with industry practice, abstracts and title reports are reviewed and updated approximately five years prior to planned development or mining of the property. If defects in title or boundaries of undeveloped reserves are discovered in the future, control of and the right to mine reserves could be adversely affected.

The following table sets forth, with respect to properties that we lease to other coal operators, the total royalty tonnage, acreage leased and the amount of income (net of related expenses) we received from royalty payments for the years ended December 31, 2007, 2006 and 2005.

Year	Total Royalty Tonnage (in thousands)	Total Coal Acreage Leased	Total Royalty Income (in thousands)
2007	13,909	218,089	$ 11,362
2006	16,445	281,165	$ 14,757
2005	19,903	275,290	$ 12,669

Royalty tonnage leased to third parties is not included in the amounts of produced tons that we report. Proven and probable reserves do not include reserves attributable to properties that we lease to third parties.

Table of Contents

At December 31, 2007, CONSOL Energy operates approximately 23% of the United States longwall mining systems.

The following table ranks the 20 largest underground mines in the United States by tons of coal produced in calendar year 2006.

MAJOR U.S. UNDERGROUND COAL MINES 2006

In millions of tons

Mine Name	Operating Company	Production
Enlow Fork	**CONSOL Energy**	**10.7**
McElroy	**CONSOL Energy**	**10.5**
Bailey	**CONSOL Energy**	**10.2**
Twenty Mile	Peabody Energy Subsidiary	8.8
Cumberland Resources	Cumberland Resources, LP. (Foundation)	7.5
SUFCO	Arch Coal, Inc.	7.4
San Juan	BHP Billiton	7.0
Century	American Energy Corp. (Murray)	6.4
Loveridge	**CONSOL Energy**	**6.4**
Emerald Resources	Emerald Resources, LP. (Foundation)	5.9
Robinson Run	**CONSOL Energy**	**5.7**
West Elk	Arch Coal, Inc.	5.7
Elk Creek	Oxbow Mining, LLC	5.1
Blacksville 2	**CONSOL Energy**	**5.0**
Buchanan	**CONSOL Energy**	**5.0**
Dotiki	Webster County Coal LLC (Alliance)	4.7
Federal No. 2	Peabody Energy Subsidiary	4.5
Warrier	Warrier Coal, LLC (Alliance)	4.5
Powhatan No. 6	The Ohio Valley Coal Company (Murray)	4.3
Dugout Canyon	Arch Coal, Inc	4.2

Source: National Mining Association

Marketing and Sales

We sell coal produced by our mining complexes and additional coal that is purchased by us for resale from other producers. We maintain United States sales offices in Atlanta, Philadelphia and Pittsburgh and an overseas office in Brussels, Belgium. In addition, we sell coal through agents, brokers and unaffiliated trading companies. In 2007, we sold 65.5 million tons of coal**,** including our portion of equity affiliates and a consolidated 49% owned variable interest entity. Ninety-one percent (91%) of these sales were sold in domestic markets. Our direct sales to domestic electricity generators represented 64% of our total tons sold in 2007. We had approximately 140 customers in 2007. During 2007, no coal customers individually accounted for more than 10% of total revenue. However, the top four coal customers accounted for more than 25% of our total revenues.

Coal Contracts

We sell coal to customers under arrangements that are the result of both bidding procedures and unsolicited offers leading to extensive negotiations. We sell coal for terms that range from a single shipment to multi-year agreements for millions of tons. During the year ended December 31, 2007, approximately 90% of the coal we produced was sold under contracts with terms of one year or more. The pricing mechanisms under our multiple-year agreements typically consist of contracts with one or more of the following pricing mechanisms:

Fixed price contracts with pre-established prices; or

Periodically negotiated prices that reflect market conditions at the time; or

Table of Contents

Base-price-plus-escalation methods which allow for periodic price adjustments based on inflation indices.

Several contracts provide the opportunity to periodically adjust the contract prices. Contract prices may be adjusted as often as quarterly based upon indices which are pre-negotiated. Many of our contracts have terms no longer than five years.

The following table sets forth, as of January 11, 2008, the total tons of coal CONSOL Energy is committed to deliver from 2008 through 2012.

	Tons of Coal to be Delivered (in millions of nominal tons)				
	2008	**2009**	**2010**	**2011**	**2012**
(1) Commitments to deliver coal at predetermined prices	63.9	34.1	20.4	10.7	1.5
(2) Commitments to deliver coal at prices to be determined by mutual agreement of the parties, including some agreements which contain predetermined price ranges	1.4	11.5	17.5	16.4	21.9
	65.3	45.6	37.9	27.1	23.4

We routinely engage in efforts to renew or extend contracts scheduled to expire. Although there are no guarantees, we have been successful in renewing or extending contracts in the past.

Contracts also typically contain force majeure provisions allowing for the suspension of performance by the customer or us for the duration of specified events beyond the control of the affected party, including labor disputes and extraordinary geological conditions. Some contracts may terminate upon continuance of an event of force majeure for an extended period, which is generally three to twelve months. Contracts also typically specify minimum and maximum quality specifications regarding the coal to be delivered. Failure to meet these conditions could result in substantial price reductions, suspension of deliveries or termination of the contract, at the election of the customer. Although the volume to be delivered under a long-term contract is stipulated, we, or the buyer may vary the timing of delivery within specified limits.

Distribution

Coal is transported from CONSOL Energy s mining complexes to customers by means of railroad cars, river barges, trucks, conveyor belts or a combination of these means of transportation. We employ transportation specialists who negotiate freight and equipment agreements with various transportation suppliers, including railroads, barge lines, terminal operators, ocean vessel brokers and trucking companies.

At December 31, 2007 we operated 25 towboats, 5 harbor boats and a fleet of more than 750 barges that serve customers along the Ohio, Allegheny and Monongahela Rivers. The barge operation allows us to control delivery schedules and has served as temporary floating storage for coal where land storage is unavailable.

Competition

The United States coal industry is highly competitive, with numerous producers selling into all markets that use coal. CONSOL Energy competes against other large producers and hundreds of small producers in the United States and overseas. The five largest producers are estimated by the 2006 National Mining Association Survey to have produced approximately 53% (based on tonnage produced) of the total United States production in 2006. The U.S. Department of Energy reported 1,424 active coal mines in the United States in 2006, the latest year for which government statistics are available. Demand for our coal by our principal customers is affected by:

- the price of competing coal and alternative fuel supplies, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power;

- coal quality;
- transportation costs from the mine to the customer; and
- the reliability of supply.

Continued demand for CONSOL Energy s coal and the prices that CONSOL Energy obtains are affected by demand for electricity, environmental and government regulation, technological developments and the availability and price of competing coal and alternative fuel supplies. 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.

Gas Operations

Our gas operations are primarily conducted by CNX Gas Corporation (CNX Gas), an 81.7% owned subsidiary of CONSOL Energy at December 31, 2007. Information presented below is 100% of CNX Gas basis; it does not include 18.3% minority interest reduction. CNX Gas primarily produces coalbed methane, which is gas that resides in coal seams. In the eastern United States, conventional natural gas fields typically are located in various types of sedimentary formations at depths ranging from 2,000 to 15,000 feet. Exploration companies often put their capital at risk by searching for gas in commercially exploitable quantities at these depths. By contrast, gas in the coal seams that we drill or anticipate drilling is typically in formations less than 2,500 feet deep which are usually better defined than deeper formations. CNX Gas believes that this contributes to lower exploration costs than those incurred by producers that operate in deeper, less defined formations. However, with CNX Gas entrance into shales and other horizontal drilling techniques, we expect to increase our exploration efforts in these emerging areas.

CNX Gas has not filed reserve estimates with any federal agency.

Areas of Operation

In the Appalachian Basin we operate principally in Central Appalachia and Northern Appalachia. We also operate in the Illinois Basin. The five areas we see playing prominent roles in our portfolio in the near future are as follows:

- first, in Central Appalachia, Virginia coalbed methane (CBM), our traditional and largest area of operation, where we have typically produced CBM from vertical wells which we drill well ahead of mining and gob gas wells;
- second, in Northern Appalachia, the Mountaineer CBM play in northwestern West Virginia and southwestern Pennsylvania, where our first major drilling program using vertical-to-horizontal well designs is into full scale development;
- third, in Northern Appalachia, the Nittany CBM play in central Pennsylvania, where we have substantial holdings and transitioned initial exploratory testing activities into full scale development;

fourth, in the Illinois Basin, Cardinal, our New Albany shale play in western Kentucky, Indiana and Illinois, which has economic potential where we are in the midst of exploratory testing activities; and

last, we believe we have Appalachian shale potential in the Marcellus, Huron, and Chattanooga shales. Additional potential exists in the Trenton Black River formation which is thought to underlie nearly all of the Appalachian shales. We will continue to evaluate our acreage position in these areas, with the commencement of an exploration program in 2008.

Table of Contents

Drilling

During 2007, 2006 and 2005, we drilled in the aggregate, 370, 272, and 184 net development wells, respectively, all of which were productive. Gob wells, and wells drilled by other operators that we participate in are excluded. As of December 31, 2007, we had no dry development wells and 32 wells are still in process. The following table illustrates the wells referenced above by geographic region:

Development Wells

	For the Years Ended December 31,		
	2007	**2006**	**2005**
Central Appalachia	294	253	176
Northern Appalachia	76	19	8
Total	370	272	184

During 2007, 2006, and 2005, we drilled in the aggregate 9, 4 and 15 net exploratory wells, respectively. The following table illustrates the exploratory wells by geographic region:

Exploratory Wells

	For the Years Ended December 31,		
	2007	**2006**	**2005**
Central Appalachia	3	2	2
Northern Appalachia		2	13
Other	6		
Total	9	4	15

Five of the other wells drilled in 2007 are still being evaluated.

Production

The following table sets forth CNX Gas net sales volume produced for the periods indicated, including our portion of equity affiliates and intersegment transactions.

	For the Years Ended December 31,		
	2007	2006	2005
Total produced coalbed methane (in millions of cubic feet)	58,249	56,135	48,390

Average Sales Prices and Lifting Costs

The following table sets forth the average sales price, including hedging transactions, and the average net lifting cost, including our portion of equity interests, for all our gas production for the periods indicated. Lifting cost is the cost of raising gas to the gathering system and does not include depreciation, depletion or amortization.

	For the Years Ended December 31,		
	2007	2006	2005
Average gas sales price including effects of financial settlements (per thousand cubic feet)	$ 7.20	$ 7.04	$ 5.90
Average net lifting cost (per thousand cubic feet)	$ 0.68	$ 0.60	$ 0.64

Table of Contents

Productive Wells and Acreage

The following table sets forth at December 31, 2007, the number of CNX Gas producing wells, developed acreage and undeveloped acreage.

	Gross	Net(1)
Producing Wells	3,800	2,989
Proved Developed Acreage	230,545	228,569
Proved Undeveloped Acreage	71,434	69,350
Unproved Acreage	3,505,970	2,960,783

Most of our development wells and acreage are located in Central Appalachia. Some leases are beyond their primary term, but these leases are extended in accordance with their terms as long as certain drilling commitments are satisfied.

(1) Net acres do not include acreage attributable to the working interests of our principal joint venture partners and the portions of certain proved developed acreage attributable to property we have leased to third-party producers. Additional adjustments (either increases or decreases) may be required as we further develop title to and further confirm our rights with respect to our various properties in anticipation of development. We believe that our assumptions and methodology in this regard are reasonable.

Sales

CNX Gas enters into physical gas sales transactions with various counterparties for terms varying in length. Reserves and production estimates are believed to be sufficient to satisfy these obligations. In the past, other than interstate pipeline outages related to maintenance, we have not failed to deliver quantities required under contract. CNX Gas has also entered into various gas swap transactions that qualify as financial cash flow hedges. These gas swap transactions exist parallel to the underlying physical transactions and represented approximately 18.4 billion cubic feet of our produced gas sales volumes for the year ended December 31, 2007 at an average price of $8.01 per thousand cubic feet. As of December 31, 2007, we expect these transactions will cover approximately 24.5 billion cubic feet of our estimated 2008 production at an average price of $8.30 per thousand cubic feet.

CNX Gas purchased firm transportation capacity on various interstate pipelines to ensure gas production flows to market. As of December 31, 2007, CNX Gas has secured firm transportation capacity to cover more than its 2008 hedged production.

The hedging strategy and information regarding derivative instruments used are outlined in item 7A, Qualitative and Quantitative Disclosures About Market Risk and in Note 25 to the Audited Consolidated Financial Statements in Item 8 of this Form 10-K.

Table of Contents

Gas Reserves

The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of any royalty interest. Proved developed and proved undeveloped gas reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and proved undeveloped gas reserves are defined by the Securities and Exchange Commission Rule 4.10(a) of Regulation S-X.

	Net Gas Reserves (millions of cubic feet) As of December 31,					
	2007		2006		2005	
	Consolidated Operations	Affiliates	Consolidated Operations	Affiliates	Consolidated Operations	Affiliates
Estimated proved developed reserves	667,726	3,584	609,700	2,200	549,574	2,672
Estimated proved undeveloped reserves	672,183		653,593		578,150	
Total estimated proved developed and undeveloped reserves	1,339,909	3,584	1,263,293	2,200	1,127,724	2,672

Discounted Future Net Cash Flows

The following table shows our estimated future net cash flows and total standardized measure of discounted, at 10%, future net cash flows:

	Discounted Future Net Cash Flows ($ in thousands) As of December 31,		
	2007	2006	2005
Future net cash flows (net of income tax)	$ 3,609,195	$ 2,483,887	$ 5,149,938
Total standardized measure of after-tax discounted future net cash flows	$ 1,389,540	$ 934,891	$ 1,870,794

Competition

We operate primarily in the eastern United States. CNX Gas believes that the gas market is highly fragmented and not dominated by any single producer. We believe that several of our competitors have devoted far greater resources than we have to gas exploration and development. CNX Gas believes that competition within our market is based primarily on operating cost and the proximity of gas fields to customers.

Power Generation

Through a joint venture with Allegheny Energy Supply Company, LLC, an affiliate of one of our largest coal customers, our 81.7% owned subsidiary, CNX Gas, owns a 50% interest in an 88-megawatt, gas-fired electric generating facility. This facility is used for meeting peak load demands for electricity. The facility is located in southwest Virginia and uses coalbed methane gas that we produce. Because it is a peaking power facility, it does not operate at all times of the year, but the facility does provide a potential sales outlet for CNX Gas of up to 22 million cubic feet per day.

Other

CONSOL Energy provides other services both to our own operations and to others. These include land services, industrial supply services, terminal services (including break bulk, general cargo and warehouse services), river and dock services, and coal waste disposal services.

Table of Contents

Land Resources

CONSOL Energy is developing property assets previously used primarily to support our coal operations or property assets currently not utilized. CONSOL Energy expects to increase the value of our property assets by:

- developing surface properties for commercial uses other than coal mining or gas development when the location of the property is suitable;
- deriving royalty income from coal, oil and gas reserves CONSOL Energy owns but does not intend to develop;
- deriving income from the sustainable harvesting of timber on land CONSOL Energy owns; and
- deriving income from the rental of surface property for agricultural and non-agricultural uses.

CONSOL Energy s objective is to improve the return on these assets without detracting from our core businesses and without significant additional capital investment.

Industrial Supply Services

Fairmont Supply Company, a CONSOL Energy subsidiary, is a general-line distributor of mining and industrial supplies in the United States. Fairmont Supply has 15 customer service centers nationwide. Fairmont Supply also provides integrated supply procurement and management services. Integrated supply procurement is a materials management strategy that utilizes a single, full-line distribution to minimize total cost in the maintenance, repair and operating supply chain. Fairmont Supply offers value-added services including on-site stores management and procurement strategies.

Fairmont Supply provides mine supplies to CONSOL Energy s mining operations. Approximately 52% of Fairmont Supply s sales in 2007 were made to CONSOL Energy s mines.

In July 2007, Fairmont Supply Company completed the acquisition of Piping and Equipment, Inc. for a cash payment, net of cash acquired, of approximately $17 million. Piping & Equipment, Inc. is a specialty distributor of pipe, valve and fittings. Piping and Equipment has eight locations in Florida, Alabama, Louisiana and Texas.

Terminal Services

In 2007, approximately 6.9 million tons of coal were shipped through CONSOL Energy s subsidiary, CNX Marine Terminal Inc. s exporting terminal in the Port of Baltimore. Approximately 55% of the tonnage shipped was produced by CONSOL Energy coal mines. The terminal can either store coal or load coal directly into vessels from rail cars. It is also one of the few terminals in the United States served by two railroads, Norfolk Southern and CSX Transportation, Inc.

River and Dock Services

CONSOL Energy s river operations, located in Monessen, Pennsylvania, transport coal from our mines, coal from other mines and non-coal commodities from river loadout facilities primarily along the Monongahela and Ohio Rivers in northern West Virginia and southwestern Pennsylvania. Products are delivered to customers along the Monongahela, Ohio and Allegheny rivers. At December 31, 2007, we operated 25 towboats, 5 harbor boats and more than 750 barges. In 2007, our river vessels transported a total of 21.7 million tons of coal and other commodities, including 7.3 million tons of coal produced by CONSOL Energy mines.

CONSOL Energy provides dock services for our mines at Alicia Dock, located on the Monongahela River in Fayette County, Pennsylvania. CONSOL Energy transfers coal from rail cars to barges for customers that receive coal on the river system.

Table of Contents

Coal Waste Disposal Services

CONSOL Energy operates an ash disposal facility on a 61-acre site in northern West Virginia to handle ash residues for coal customers that are unable to dispose of ash on-site at their generating facilities. The ash disposal facility can process 200 tons of material per hour, and is expected to dispose of approximately 140 thousand tons of fly ash in the current contract year. CONSOL Energy has a long-term contract with a cogeneration facility to supply coal and take the residual fly ash and bottom ash. Bottom ash is disposed locally at the cogeneration facility for road construction and other purposes.

Employee and Labor Relations

At December 31, 2007, CONSOL Energy had 7,728 employees, 36% of whom were represented by the United Mine Workers of America (UMWA). A five-year labor agreement commenced January 1, 2007. This agreement expires December 31, 2011 and provides for a 20% across-the-board wage increase over its duration. Wages increased $1.50 per hour in 2007, and will increase $1.00 per hour in 2008 and $0.50 per hour for 2009 through 2011. Other terms of the agreement require additional contributions to be made into the employee benefit funds. Full health-care benefits for active and retired members and their dependents will continue with no increase in co-payments. Newly employed inexperienced employees represented by the UMWA, hired after January 1, 2007 will not be eligible to receive retiree health care benefits. In lieu of these benefits, these employees will receive a defined contribution benefit of $1 per each hour worked.

Laws and Regulations

The coal mining and gas industries are 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 properties after mining or gas operations are completed, management of materials generated by mining and gas operations, surface subsidence from underground mining, water discharge effluent limits, water appropriation, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, endangered plant and wildlife protection, limitations on land use, storage of petroleum products and substances that are regarded as hazardous under applicable laws, and management of electrical equipment containing polychlorinated biphenyls, or PCBs. In addition, the electric power generation industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for CONSOL Energy s coal and gas products. The possibility exists that new legislation or regulations may be adopted which would have a significant impact on CONSOL Energy s mining or gas operations or our customers ability to use coal or gas and may require CONSOL Energy or our customers to change their operations significantly or incur substantial costs.

Numerous governmental permits and approvals are required for mining and gas 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 CONSOL Energy could provide a basis to revoke existing permits and to deny the issuance of additional permits. CONSOL Energy is, or may be, required to prepare and present to federal, state or local authorities data and/or analyses pertaining to the effect or impact that any proposed exploration for or production of coal or gas 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 which restricts our ability to conduct our mining and gas operations or to do so profitably. Future legislation and administrative regulations may increasingly emphasize the protection of the environment, employee health and safety and, as a consequence, the activities of CONSOL Energy 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 to CONSOL Energy and 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 and gas production for all domestic coal and gas producers. We also post performance bonds or letters of credit pursuant to state oil and gas laws and regulations to guarantee reclamation of gas well sites and plugging of gas wells. We endeavor to conduct our mining and gas operations in compliance with all applicable federal, state and local laws and regulations. However, because of extensive and comprehensive regulatory requirements, violations during mining and gas operations occur from time to time. None of the violations to date, or the monetary penalties assessed have been material. CONSOL Energy made capital expenditures for environmental control facilities of approximately $17.6 million, $10.2 million, and $8.6 million for the years ended December 31, 2007, 2006 and 2005, respectively. CONSOL Energy expects to have capital expenditures of $14.6 million for 2008 for environmental control facilities.

Mine Health and Safety Laws

Mine accidents involving multiple fatalities occurred during the calendar years 2007 and 2006 at mines operated by other coal companies. These accidents attracted widespread public attention and have resulted in both federal government and some state government changes to statutory and regulatory control of mine safety, particularly for underground mines. Because nearly all of our mines are underground, these legislative and regulatory changes could affect our performance.

The actions taken thus far by federal and state governments include requiring: the caching of additional supplies of self-contained self rescuer (SCSR) devices underground; providing breathable air for all underground miners for 96 hours; the purchase and installation during the next several years of electronic communication and personal tracking devices underground; the placement, in various mine areas, of rescue chambers, structures designed to provide refuge for groups of miners for long periods of time during a mine emergency when evacuation from the mine is not possible which will provide breathable air for all underground miners for 96 hours; the possible reconstruction of existing seals in worked-out areas of mines; and additional training and testing requirements that created the need to hire additional employees.

In reviewing actions taken to date, we estimate that implementation of these new requirements could cost $35 million to $45 million during the period from 2006 until the end of 2009. The actual costs will depend primarily on: the number of additional SCSR oxygen units purchased, the design requirements as well as the extent of deployment of rescue chambers, final guidelines regarding sealed areas, final interpretation of other regulatory requirements, and final approval of mine-by-mine implementation plans.

We have reviewed our coal sales agreements to determine the degree to which costs related to these regulatory requirements may be passed through to customers. While the amount will vary by contract, we have been billing the cost of implementation to customers in most of our existing sales agreements. Responses from customers have varied.

Black Lung Legislation

Under federal black lung benefits legislation, each coal mine operator is required to make payments of black lung benefits or contributions to:

- current and former coal miners totally disabled from black lung disease;

certain survivors of a miner who dies from black lung disease or pneumoconiosis; and

a trust fund for the payment of benefits and medical expenses to claimants whose last mine employment was before January 1, 1970, where no responsible coal mine operator has been identified

Table of Contents

for claims (where a miner s last coal employment was after December 31, 1969), or where the responsible coal mine operator has defaulted on the payment of such benefits. The trust fund is funded by an excise tax on U.S. production of up to $1.10 per ton for deep mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In addition to the federal legislation, we are also liable under various state statutes for black lung claims.

Retiree Health Benefits Legislation

The Coal Industry Retiree Health Benefit Act of 1992 (the Act) established the Combined Benefit Fund (the Combined Fund). The Combined Fund provides medical and death benefits for all beneficiaries including orphan retirees of the former UMWA Benefit Trusts who were actually receiving benefits as of July 20, 1992. The Act also created a second benefit fund for United Mine Worker retirees, the 1992 Benefit Plan. The 1992 Benefit Fund principally provides medical and death benefits to orphan UMWA-represented members eligible for retirement on February 1, 1993, and who actually retired between July 20, 1992 and September 30, 1994. The Act provides for the assignment of beneficiaries to former signatory employers or related companies and the allocation of unassigned beneficiaries (referred to as orphans) to companies using a formula set forth in the Act. The task of calculating the annual per beneficiary premium that assigned operators are obligated to pay to the Combined Fund is the responsibility of the Commissioner of Social Security. The UMWA 1993 Benefit Plan is a defined contribution plan that was created as the result of negotiations for the National Bituminous Coal Wage Agreement (NBCWA) of 1993. This plan provides health care benefits to orphan UMWA retirees who are not eligible to participate in the Combined Fund, the 1992 Benefit Fund, or whose last employer signed the 1993 or later NBCWA and who subsequently goes out of business.

The Coal Act required some of our subsidiaries to make premium payments to the Combined Fund and to the 1992 Benefit Plan for the cost of our retirees and orphan retirees in the Combined Fund and the 1992 Benefit Plan. In addition, the collective bargaining agreement with the United Mine Workers requires our signatory subsidiaries to make specified payments to the 1993 Benefit Plan through 2011. The Tax Relief and Health Care Act of 2006 (the 2006 Act) provides additional federal funding for these orphan costs by authorizing general fund revenues and expanding transfers of interest from the Abandon Mine Land (AML) trust fund. The additional federal funding, depending upon its magnitude and the amount of orphan benefits payable, should cover the orphan premium payments due under the Combined Fund as well as, after a phase-in period, the premium payments due under the 1992 Benefit Plan. The 1992 Plan has a phase-in period for the federal contributions. Federal contribution will be 25% in 2008, 50% in 2009, 75% in 2010 and 100% thereafter. In addition, federal contributions are also to be phased-in over this same period with respect to the costs for those orphan retirees as of December 31, 2006 under the 1993 Plan. Under the 2006 Act, these general fund contributions to the Combined Fund, the 1992 Benefit Plan, the 1993 Benefit Plan and certain Abandoned Mine Land payments to the states and Indian tribes are collectively limited by an aggregate annual cap of $490 million. These federal contributions do not apply to our subsidiaries assigned retired miners, and therefore our subsidiaries will continue to pay premium payments for our assigned retired miners who receive benefits under the Plans. In addition, our subsidiaries remain responsible for making orphan premium payments to these Plans to the extent that the federal contributions are not sufficient to cover the benefits.

Pension Protection Act

The Pension Protection Act of 2006 (the Pension Act) has simplified and transformed 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 (EGTRRA), made permanent the diversification rights and investment education provisions for plan participants and encourages automatic enrollment in defined contribution 401(k) plans. In general, most provisions of the Pension Act of 2006 are in 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 includes a funding target phase-in provision consisting of a 92% funding target in

25

Table of Contents

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, will be deemed to be at risk and will be subject to additional funding requirements. Our current funding ratio is 90%. Our intent is to meet the 100% requirement by 2011.

Environmental Laws

CONSOL Energy is subject to various federal environmental laws, including:

- the Surface Mining Control and Reclamation Act of 1977,
- the Clean Air Act,
- the Clean Water Act,
- the Toxic Substances Control Act,
- the Endangered Species Act,
- the Comprehensive Environmental Response, Compensation and Liability Act,
- the Emergency Planning and Community Right to Know Act, and
- the Resource Conservation and Recovery Act

as administered and enforced by United States Environmental Protection Agency (EPA) and/or authorized federal or state agencies, as well as state laws of similar scope, and other state environmental and conservation laws in each state in which CONSOL Energy operates.

These environmental laws require reporting, permitting and/or approval of many aspects of coal mining and gas operations. Both federal and state inspectors regularly visit mines and other facilities to ensure compliance. CONSOL Energy has ongoing compliance and permitting programs designed to ensure compliance with such environmental laws.

Given the retroactive nature of certain environmental laws, CONSOL Energy has incurred and may in the future incur liabilities in connection with properties and facilities currently or previously owned or operated as well as sites to which CONSOL Energy or our subsidiaries sent waste materials.

Surface Mining Control and Reclamation Act

The Surface Mining Control and Reclamation Act (SMCRA) establishes minimum national operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. The Act requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. Permits for all mining operations must be obtained from the Federal Office of Surface Mining Reclamation and Enforcement (OSM) or, where state regulatory agencies have adopted federally approved state programs under SMCRA, the appropriate state regulatory authority. States that operate federally approved state programs may impose standards which are more stringent than the requirements of SMCRA and OSM s regulations and in many instances, have done so. All states in which CONSOL Energy s active mining operations are located have achieved primary jurisdiction for enforcement of the Act through approved state programs.

SMCRA permit provisions include requirements for coal exploration; baseline environmental data collection and analysis; mine plan development; topsoil removal, storage and replacement; selective handling of overburden materials; mine pit backfilling and grading; protection of the hydrologic balance; subsidence control for underground mines; refuse disposal plans; surface drainage control; mine drainage and mine discharge control and treatment; and site reclamation. The mining permit application process, whether state or federal, is initiated by collecting baseline data to adequately characterize the pre-mine environmental condition of the permit area. This work includes surveys of cultural resources, soils, vegetation and wildlife, and assessment of surface and ground water hydrology, climatology and wetlands. In conducting this work, we collect geologic data to define and model the soil and rock structures and coal that we will mine. We develop mine and reclamation plans by utilizing this geologic data and incorporating elements of the environmental data. The mine and reclamation plan incorporates the provisions of SMCRA, the state programs and the complementary environmental programs that impact coal mining. Detailed engineering plans are included for all surface facilities built as part of the mine, including roads, ponds, shafts and slopes, boreholes, portals, pipelines and power lines, excess spoil disposal areas and coal refuse disposal facilities. Also included in the permit application are documents defining corporate ownership and control, property ownership and agreements pertaining to coal, minerals, oil and gas, water rights, rights of way and surface land and documents required by the OSM Applicant Violator System. We also must list all public and privately-owned structures located within minimum defined distances near to or above our mines and mining facilities. Once a permit application is prepared and submitted to the regulatory agency, it goes through an administrative completeness review and a separate technical review. Public notice of the proposed permit application is given in a local newspaper followed by a public comment period before a permit can be issued. Some mining permits take over a year to prepare, depending on the size and complexity of the mine and can take six months to three years to be issued. Regulatory authorities have considerable discretion in the timing of the permit issuance. The public has the right to comment on and otherwise participate in the permitting process, including through administrative appeals of permits and possibly further appeals in the courts. The mine operator must submit a bond or otherwise secure the performance of reclamation obligations, including, as deemed appropriate by the regulatory authority, a bond sufficient to cover the costs of long-term treatment of mine drainage discharges from closed facilities or ones from which a post-mining discharge is anticipated. The earliest a reclamation bond can be fully released is five years after reclamation has been completed, however, partial releases may be obtained as certain stages of reclamation are completed. All states impose on mine operators the responsibility for repairing or compensating for damage occurring on the surface as a result of mine subsidence, a possible consequence of longwall or other methods of underground mining, including an obligation to restore or replace water supplies adversely affected by underground mining. All states also impose an obligation on surface mining operations to replace domestic water supplies adversely affected by such operations. In addition, SMCRA imposes a reclamation fee on all current mining operations, the proceeds of which are deposited in the Abandoned Mine Reclamation Fund (AML Fund), which is used to restore unreclaimed and abandoned mine lands mined before 1977. The original amounts of the reclamation fees were $0.35 per ton for surface mined coal and $0.15 per ton for underground mined coal. The Tax Relief and Health Care Act of 2006 amended SMCRA to provide for two reductions (each being ten percent of the original fee amounts) that should take effect in federal fiscal years 2008 and 2013. Thus, from October 1, 2007 through September 30, 2012, the per ton fees will be $0.315 per ton for surface mined coal and $0.135 per ton for underground mined coal. From October 1, 2012 through September 30, 2021, the fees will be $0.28 per ton for surface mined coal and $0.12 per ton for underground mined coal.

Under the SMCRA, responsibility for unabated violations of SMCRA and other specified environmental laws, unpaid civil penalties and unpaid reclamation fees of subsidiaries and affiliates can be imputed to the parents and related companies if deemed to be owned or controlled by such entities. Data describing such ownership links must be provided by CONSOL Energy to the regulatory authorities. Similar violations by independent contract mine operators can also be imputed to other companies which are deemed, according to the regulations, to have owned or controlled the contract mine operator. Sanctions against the owner or controller are quite severe and can include being blocked from receiving new permits and revocation of any permits that have been issued since the time of the violations or, in the case of civil penalties and reclamation fees, since the time such amounts became due.

In the Commonwealth of Pennsylvania, where CONSOL Energy operates four longwall mines, approximately $16.0 million and $8.8 million of expenses were incurred during the years ended December 31, 2007 and 2006, respectively, to abate enforcement actions related to the impacts on streams from subsidence. Recent interpretations of technical guidance documents related to impacts of longwall mining on Pennsylvania streams requires additional analysis on stream flows and biological statistics. We have received violation notices for past longwall activities which resulted in lower stream flows and water pooling areas both of which we are in the process of remediating. We also are completing additional stream analysis in order to comply with these recent interpretations at current Pennsylvania mining operations. Future Pennsylvania Department of Environmental Protection enforcement actions could cause CONSOL Energy to change mine plans, to incur significant costs, and potentially even shut down mines in order to meet compliance requirements. However, these impacts on streams have occurred primarily at the Bailey Mine. The degree to which the mine impacts a stream is related to the geology of the area, including the vertical distance from the stream channel to the coal seam. Over the next several years the coal seam being mined by the Bailey Mine becomes progressively deeper. This change in geologic setting is expected to lessen the adverse impacts on streams. We currently estimate expenses related to subsidence of streams in Pennsylvania will be approximately $7.8 million for the year ended December 31, 2008.

Clean Air Act and Related New Regulations

The federal Clean Air Act and similar state laws and regulations which regulate emissions into the air, affect coal mining, coal handling and processing, and gas processing operations primarily through permitting and/or emissions control requirements. For example, regulations relating to fugitive dust and coal combustion emissions could restrict CONSOL Energy s ability to develop new mines or require CONSOL Energy to modify our operations. National Ambient Air Quality Standards (NAAQS) for particulate matter resulted in some areas of the country being classified as non-attainment for fine particulate. Because thermal dryers located at coal preparation plants burn coal and emit particulate matter, CONSOL Energy s mining operations are likely to be directly affected where the NAAQS are implemented by the states. In addition, in September 2006, EPA promulgated revised particulate matter NAAQS.

CONSOL Energy believes we have obtained all necessary permits under the Clean Air Act. The expiration dates of these permits range from April 18, 2008 through March 18, 2015. CONSOL Energy monitors permits required by operations regularly and takes appropriate action to extend or obtain permits as needed.

The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of the coal fired electric power generating plants operated by our customers. Coal contains impurities, such as sulfur, mercury and other constituents, many of which are released into the air when coal is burned. New environmental regulations governing emissions from coal-fired electric generating plants could affect demand for coal as a fuel source and affect the volume of our sales. For example, the federal Clean Air Act places limits on sulfur dioxide, nitrogen dioxide, and mercury emissions from electric power plants.

Further sulfur dioxide emission reductions are required by the Clean Air Interstate Rules (CAIR), which were promulgated by the EPA in 2005. In order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), blend high sulfur coal with low sulfur coal or switch to low sulfur coal or other fuels. The CAIR rules significantly reduce sulfur dioxide emission allowances available to electric power plants. More strict emission limits mean few coals can be burned without the installation of supplemental environmental control technology in the form of scrubbers. Many of our customers are in the process of installing scrubbers in response to the new emissions requirements. We estimate that by 2012, more than half of the installed, coal-fired power plant capacity east of the Mississippi will be scrubbed. The increase in scrubbed capacity allows customers to consider purchasing more of our higher sulfur coals.

In October 1998, the EPA finalized a rule requiring a number of eastern U.S. states to make substantial reductions in nitrogen oxide emissions by June 1, 2004. The installation of additional control measures to achieve these reductions makes it more costly to operate coal-fired power plants and could make coal a less attractive fuel. In addition, reductions in nitrogen oxide emissions can be achieved at a low capital cost through a combination of low nitrogen oxide burners and coal produced in western U.S. coal mines. As a result, changes in current emissions standards could also impact the economic incentives for eastern U.S. coal-fired power plants to consider using more coal produced in western U.S. coal mines. The CAIR rules promulgated in 2005 target electric utilities for further reductions in NOx and impose emissions caps for NOx on electric generating units that take effect in 2010.

Table of Contents

In 2005, the EPA finalized the Clean Air Mercury Rule (CAMR) which imposes caps on mercury emissions from coal-fired electric generating units. The first phase of the emission caps take effect in 2010. The CAMR provides for an allocation of mercury emission allowances to individual power plants based on the type of coal fired in the unit. Units firing bituminous coal are allocated less emission allowances than those firing subbituminous coal. In addition, various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units. The CAMR rule and state regulation of mercury emissions from coal-fired electric generating units could impact the market for coal.

A regional haze program initiated by the EPA to protect and to improve visibility at and around national parks, national wilderness areas and international parks may restrict the construction of new coal-fired power plants whose operation may impair visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations.

The United States Department of Justice, on behalf of the EPA, has filed lawsuits against several investor-owned electric utilities and brought an administrative action against one government-owned utility for alleged violations of the Clean Air Act. These lawsuits could require the utilities to pay penalties, install pollution control equipment or undertake other emission reduction measures which could positively or negatively impact their demand for CONSOL Energy coal. One such suit was settled in October 2007, by the owner of sixteen coal fueled electric generating plants located in Indiana, Kentucky, Ohio, Virginia and West Virginia. Although the utility did not admit any violations of the Clean Air Act, it agreed to annual sulfur dioxide and nitrogen oxides emission limits for all of its plants and it agreed to install additional emission controls on two of its plants.

Also, numerous proposals have been made at the international, national, regional and state levels that are intended to limit or capture emissions of greenhouse gases, such as carbon dioxide and several states have adopted measures intended to reduce greenhouse gas loading in the atmosphere. If comprehensive legislation focusing on greenhouse gas emissions is enacted by the United States or individual states, it may adversely affect the use of and demand for fossil fuels, particularly coal, as an energy source for electricity generation. Future regulation of greenhouse gases could occur in the United States pursuant to treaty obligations, regulation under the Clean Air Act, or regulation under state laws. In 2007, the U. S. Supreme Court held in Massachusetts v. EPA, that EPA had authority to regulate greenhouse gases under the Clean Air Act, reversing EPA s interpretation of the act. This decision could lead to federal regulation of greenhouse gas emissions from coal fired electric generating stations which could adversely affect the demand for coal for electricity generation. Also, in 2005, seven northeastern states (Connecticut, Delaware, Maine, New Jersey, New Hampshire, New York and Vermont) signed the Regional Greenhouse Gas Initiative (RGGI), calling for a ten percent reduction of carbon dioxide emission by 2019, with compliance to begin in 2009. Maryland has also joined RGGI. In addition, California has enacted legislation to establish greenhouse gas emission standards for electric power generating plants in connection with new long-term power plant investments.

Clean Water Act

The federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. In combination with existing requirements, new requirements under the Clean Water Act and corresponding state laws; including those relating to protection of impaired waters so designated by individual states through the use of new effluent limitations known as Total Maximum Daily Load (TMDL) limits; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; and requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides and selenium; and protecting streams, wetlands, other regulated water sources and associated riparian lands from the surface impacts of underground mining, may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows.

Table of Contents

The Army Corps of Engineers (the COE) is empowered to issue nationwide permits for specific categories of filling activity that are determined to have minimal environmental adverse effects in order to save the cost and time of issuing individual permits under Section 404 of the Clean Water Act. Individual permits are required for activities determined to have more significant impacts to waters of the United States. Nationwide Permit 21 authorizes the disposal of dredge-and-fill material from mining activities into the waters of the United States. Nationwide Permit 21 was renewed in 2007 allowing its continued use. On October 23, 2003, several citizens groups sued the COE in the U.S. District Court for the Southern District of West Virginia seeking to invalidate nationwide permits utilized by the COE and the coal industry for permitting most in-stream disturbances associated with coal mining, including excess spoil valley fills and refuse impoundments. The plaintiffs sought to enjoin the prospective approval of these nationwide permits and to enjoin some coal operators from additional use of existing nationwide permit approvals until they obtain more detailed individual permits. On July 8, 2004, the court issued an order enjoining the further issuance of Nationwide Permit 21 and rescinded certain listed permits where construction of valley fills and surface impoundments had not commenced. On August 13, 2004, the court extended the ruling to all Nationwide Permit 21 issued within the Southern District of West Virginia. Although CONSOL Energy had no operations that were interrupted, based on the District Court Opinion, we decided to convert certain current and planned applications for Nationwide Permit 21 in southern West Virginia to applications for individual permits. A similar lawsuit was filed on January 27, 2005 in the U.S. District Court for the Eastern District of Kentucky. However, the District Court for the Southern District of West Virginia opinion was reversed by the Fourth Circuit Court of Appeals. Because of legal challenges to the validity and use of Nationwide Permit 21, CONSOL Energy decided to apply for individual permits for its facilities as needed in southern West Virginia and Kentucky. In addition to the challenges to Nationwide Permit 21, another suit was filed in the Southern District of West Virginia in 2005 challenging the validity of COE determinations to issue individual permits for valley fills associated with certain surface mining operations. In March 2007, the District Court issued a decision remanding the individual permits back to the COE to, among other things, reconsider the COE s determinations that the permits required adequate mitigation of the impacts of fills on streams. That District Court opinion is on appeal to the Fourth Circuit Court of Appeals. Although the 2007 District Court decision did not interrupt any of our mining operations, we amended mitigation plans in pending individual permit applications to address the concerns stated in the District Court decision. The various challenges to Nationwide Permit 21 and to individual COE permits resulted in a period of time when the COE was not issuing permits, which resulted in a backlog of pending permit applications. Thus, we may not receive COE permits when they are needed. Additional permit delays and costs have resulted from implementation by the COE and EPA of guidance on Clean Water Act jurisdictional determinations of waters of the United States, which was in response to the 2006 U.S. Supreme Court decision in Rapanos v. U.S. The Rapanos guidance is also likely to lead to an increase in streams and wetlands that are identified as requiring protection and/or mitigation under the Clean Water Act.

Comprehensive Environmental Response, Compensation and Liability Act (Superfund)

The Comprehensive Environmental Response, Compensation and Liability Act (Superfund) and similar state laws create liabilities for the investigation and remediation of releases of hazardous substances into the environment and for damages to natural resources. 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, including underground storage tanks, solid and hazardous waste disposal and other matters under the Comprehensive Environmental Response, Compensation and Liability Act and similar state environmental laws. We also must comply with reporting requirements under the Emergency Planning and Community Right-to-Know Act and the Toxic Substances Control Act.

From time to time, we have been the subject of administrative proceedings, litigation and investigations relating to environmental matters. We have been in the past and currently are named as a potentially responsible party at Superfund sites. We may become involved in future proceedings, litigation or investigations and incur liabilities that could be materially adverse to us.

Table of Contents

Resource Conservation and Recovery Act

The federal Resource Conservation and Recovery Act (RCRA) and corresponding state laws and regulations affect coal mining and gas operations by imposing requirements for the treatment, storage and disposal of hazardous wastes. Facilities at which hazardous wastes have been treated, stored or disposed are subject to corrective action orders issued by the EPA which could adversely affect our results, financial condition and cash flows.

RCRA exempted fossil fuel combustion wastes from hazardous waste regulation until the EPA completed a report to Congress and made a determination on whether the wastes should be regulated as hazardous. In a 1993 regulatory determination, the EPA addressed some high volume-low toxicity coal combustion wastes generated at electric utility and independent power producing facilities, such as coal ash. In May 2000, the EPA concluded that coal combustion wastes do not warrant regulation as hazardous under RCRA resulting in coal combustion wastes remaining exempt from hazardous waste regulation. However, the EPA has also determined that national non-hazardous waste regulations under RCRA are needed for coal combustion wastes disposed in surface impoundments and landfills and used as mine-fill, and the Office Surface Mining is currently developing these regulations. The agency also concluded that beneficial uses of these wastes, other than for mine-filling, pose no significant risk and no additional national regulations are needed. Most state hazardous waste laws also exempt coal combustion waste, and instead treat it as either a solid waste or a special waste. The loss of the hazardous waste exemption for coal combustion waste, or the adoption of new regulations for disposing of coal combustion waste which impose significant additional costs, could adversely affect the demand for coal for electricity generation.

Federal Coal Leasing Amendments Act

Mining operations on federal lands in the western United States are affected by regulations of the United States Department of the Interior. The Federal Coal Leasing Amendments Act of 1976 amended the Mineral Lands Leasing Act of 1920 which authorized the leasing of federal coal lands for coal mining. The Federal Coal Leasing Amendments Act increased the royalties payable to the United States Government for federal coal leases and required diligent development and continuous operations of leased reserves within a specified period of time. Subtitle D of the Energy Policy Act of 2005 (Pub. L. 109-58) contained the Coal Leasing Amendments Act of 2005, which includes provisions designed to facilitate efficient and economic development of federal coal leases. The United States Department of the Interior has stated that it intends to promulgate new regulations and implement these 2005 amendments. Regulations adopted by the United States Department of the Interior to implement such legislation could affect coal mining by CONSOL Energy from federal coal leases for operations developed that would incorporate such leases. Currently, CONSOL Energy s only active operation with federal coal leases is Emery Mine.

Endangered Species Act

The Federal Endangered Species Act (ESA) and similar state laws protect species threatened with extinction. Protection of endangered species may affect our ability to obtain permits, may delay issuance of mining permits, or may cause us to modify mining plans to avoid or minimize impacts to endangered species or their habitats. A number of species indigenous to the areas where we operate are protected under the ESA. Based on the species that have been identified and the current application of applicable laws and regulations, we do not believe that there are any species protected under the ESA or state laws that would materially and adversely affect our ability to mine coal from our properties.

Federal Regulation of the Sale and Transportation of Gas

Various aspects of CNX Gas operations are regulated by agencies of the federal government. The Federal Energy Regulatory Commission regulates the transportation and sale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. While first sales by producers

Table of Contents

of natural gas, and all sales of condensate and natural gas liquids can be made currently at uncontrolled market prices, Congress could reenact price controls in the future. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Regulations and orders set forth by the Federal Energy Regulatory Commission also impact the business of CNX Gas to a certain degree. Although the Federal Energy Regulatory Commission does not directly regulate CNX Gas production activities, the Federal Energy Regulatory Commission has stated that it intends for certain of its orders to foster increased competition within all phases of the natural gas industry. Additionally, the Federal Energy Regulatory Commission continues to review its transportation regulations, including whether to allocate all short-term capacity on the basis of competitive auctions and whether changes to its long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. Additional Federal Energy Regulatory Commission orders were adopted based on this review with the goal of increasing competition for natural gas markets and transportation.

The Federal Energy Regulatory Commission has also issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the Federal Energy Regulatory Commission does not have jurisdiction over services provided by these facilities, then such facilities and services may be subject to regulation by state authorities in accordance with state law. In addition, the Federal Energy Regulatory Commission s approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to Federal Energy Regulatory Commission regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

CNX Gas owns certain natural gas pipeline facilities that we believe meet the traditional tests which the Federal Energy Regulatory Commission has used to establish a pipeline s status as a gatherer not subject to the Federal Energy Regulatory Commission jurisdiction.

Additional proposals and proceedings that might affect the gas industry may be pending before Congress, the Federal Energy Regulatory Commission, the Minerals Management Service, state commissions and the courts. CNX Gas cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, CNX Gas does not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon the capital expenditures, earnings or competitive position of CNX Gas or its subsidiaries. No material portion of CNX Gas business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

State Regulation of Gas Operations United States

CNX Gas operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the disposal of fluids used in connection with operations, and gas operations producing coalbed methane in relation to active mining. CNX Gas operations are also subject to various conservation laws and regulations. These include regulations that affect the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of gas properties. In addition, state conservation laws establish maximum rates of production from gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. A number of states have either enacted new laws or may be considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental and in

some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. CNX Gas gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although CNX Gas does not believe that it would be affected by such regulation any differently than other natural gas producers or gatherers. However, these regulatory burdens may affect profitability, and CNX Gas is unable to predict the future cost or impact of complying with such regulations.

Available Information

CONSOL Energy maintains a website on the World Wide Web at *www.consolenergy.com*. CONSOL Energy makes available, free of charge, on this website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the 1934 Act), as soon as reasonably practicable after such reports are available electronically filed with, or furnished to the SEC, and are also available at the SEC s website at *www.sec.gov*.

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 Directors and Executive Officers of the Registrant (included herein pursuant to Item 401 (b) of Regulation S-K).

Item 1A. ***Risk Factors*****.**

Investment in our securities is subject to various risks, including risks and uncertainties inherent in our business. The following sets forth factors related to our business, operations, financial position or future financial performance or cash flows which could cause an investment in our securities to decline and result in a loss.

A significant extended decline in the prices CONSOL Energy receives for our coal and gas could adversely affect our operating results and cash flows.

CONSOL Energy s results of operations are highly dependent upon the prices we receive for our coal, which are closely linked to consumption patterns of the electric generation industry and certain industrial and residential patterns where gas is the principal fuel. Extended or substantial price declines for coal would adversely affect our operating results for future periods and our ability to generate cash flows necessary to improve productivity and expand operations. Prices of coal may fluctuate due to factors beyond our control such as overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; technological advances affecting energy consumption; domestic and foreign government regulations; price and availability of alternative fuels; price of foreign imports and weather conditions. Any adverse change in these factors could result in weaker demand and possibly lower prices for our production, which would reduce our revenues.

Natural gas prices are volatile, and even relatively modest drops in prices can significantly affect our financial results and impede growth. Changes in natural gas prices have a significant impact on the value of our reserves and on our cash flow. In the past we have used hedging transactions to reduce our exposure to market price volatility when we deemed it appropriate. If we choose not to engage in, or reduce our use of hedging arrangements in the future, we may be more adversely affected by changes in natural gas and oil prices than our competitors who engage in hedging arrangements to a greater extent than we do. Prices for natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as: the domestic and foreign supply of natural gas; the price of foreign imports; overall domestic and global economic conditions; the consumption pattern of industrial consumers, electricity generators and residential users; weather conditions; technological advances affecting energy consumption; domestic and foreign governmental regulations; proximity and capacity of gas pipelines and other transportation facilities; and the price and availability of alternative fuels.

Table of Contents

Many of these factors may be beyond our control. Earlier in this decade, natural gas prices were lower than they are today. Lower natural gas prices may not only decrease our revenues on a per unit basis, but may also limit our access to capital. A significant decrease in price levels for an extended period would negatively affect us in several ways including our cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production; and access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable. Additionally, lower natural gas prices may reduce the amount of natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management s plans change with respect to those assets. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

If customers do not extend existing contracts or do not enter into new long-term contracts for coal, profitability of CONSOL Energy s operations could be affected.

During the year ended December 31, 2007, approximately 90% of the coal CONSOL Energy produced was sold under long-term contracts (contracts with terms of one year or more). If a substantial portion of CONSOL Energy s long-term contracts are modified or terminated or if force majeure is exercised, CONSOL Energy would be adversely affected if we are unable to replace the contracts or if new contracts were not at the same level of profitability. The profitability of our long-term coal supply contracts depends on a variety of factors, which vary from contract to contract and fluctuate during the contract term, including our production costs and other factors. Price changes, if any, provided in long-term supply contracts may not reflect our cost increases, and therefore, increases in our costs may reduce our profit margins. In addition, in periods of declining market prices, provisions for adjustment or renegotiation of prices and other provisions may increase our exposure to short-term coal price volatility. As a result, CONSOL Energy may not be able to obtain long-term agreements at favorable prices (compared to either market conditions, as they may change from time to time, or our cost structure) and long-term contracts may not contribute to our profitability.

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

For the year ended December 31, 2007, we derived over 25% of our total revenues from sales to our four largest coal customers. At December 31, 2007, we had approximately 16 coal supply agreements with these customers that expire at various times from 2008 to 2021. We are currently discussing the extension of existing agreements or entering into new long-term agreements with some of these customers, but these negotiations may not be successful and these customers may not continue to purchase coal from us under long-term coal supply agreements. If any one of these four customers were to significantly reduce their purchases of coal from us, or if we were unable to sell coal to them on terms as favorable to us as the terms under our current agreements, our financial condition and results of operations could suffer materially.

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

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. Our customer base has changed with deregulation as some utilities sold their power plants to their non-regulated affiliates or third parties. These new power plant owners may have credit ratings that are below investment grade. If the creditworthiness of our customers declines significantly, our $165 million accounts receivable securitization program and our business could be adversely affected.

34

Table of Contents

Disruption of rail, barge, overland conveyor and other systems that deliver CONSOL Energy s coal or an increase in transportation costs could make CONSOL Energy s coal less competitive.

Coal producers depend upon rail, barge, trucking, overland conveyor and other systems to provide access to markets. Disruption of transportation services because of weather-related problems, strikes, lock-outs, break-downs of locks and dams or other events could temporarily impair our ability to supply coal to customers and adversely affect our profitability. 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 our coal less competitive.

Competition within the coal and gas industries may adversely affect our ability to sell our products, or a loss of our competitive position because of overcapacity in these industries could adversely affect pricing which could impair our profitability.

CONSOL Energy competes with coal producers in various regions of the United States and with some foreign coal producers for domestic sales primarily to power generators. CONSOL Energy also competes with both domestic and foreign coal producers for sales in international markets. Demand for our coal by our principal customers is affected by the delivered price of competing coals, other fuel supplies and alternative generating sources, including nuclear, natural gas, oil and renewable energy sources, such as hydroelectric power. CONSOL Energy sells coal to foreign electricity generators and to the more specialized metallurgical coal market, both of which are significantly affected by international demand and competition.

Recent increases in coal prices could encourage the development of expanded capacity by new or existing coal producers. Any resulting overcapacity could affect our ability to sell coal or reduce coal prices and therefore reduce our revenues.

The gas industry is intensely competitive with companies from various regions of the United States and we may compete with foreign companies for domestic sales, many of whom are larger and have greater financial, technological, human and other resources. If we are unable to compete, our operating results and financial position may be adversely affected. For example, one of our competitive strengths is being a low-cost producer of gas. If our competitors can produce gas at a lower cost than us, it would effectively eliminate our competitive strength in that area. In addition, larger companies may be able to pay more to acquire new gas properties for future exploration, limiting our ability to replace gas we produce or to grow our production. Our ability to acquire additional properties and to discover new gas resources also depends on our ability to evaluate and select suitable properties and to consummate these transactions in a highly competitive environment.

We require a skilled workforce to run our business. If we cannot hire qualified people to meet replacement or expansion needs, we may not be able to achieve planned results.

Most of our workforce is comprised of people with technical skills related to the production of coal and gas. Approximately 55 percent of our workforce is 50 years of age or older. Based on our experience, we expect a high percentage of our employees to retire between now and the next five to seven years. This will require us to conduct an expanded and sustained effort to recruit new employees to replace those who retire and to fill new jobs as we grow our business. Some areas of Appalachia, most notably in eastern Kentucky, currently have a shortage of skilled labor. Because we have operations in this area, the shortage could make it more difficult to meet our staffing needs and therefore, our results may be adversely affected. Finally, a lack of qualified people may also affect companies that we use to perform certain specialized work. If these companies cannot find enough qualified workers, it may delay projects done for us or increase our costs.

The characteristics of coal may make it difficult for coal users to comply with various environmental standards, which are continually under review by international, federal and state agencies, related to coal combustion. As a result, they may switch to other fuels, which would affect the volume of CONSOL Energy s sales.

Coal contains impurities, including sulfur, mercury, chlorine and other elements or compounds, many of which are released into the air when coal is burned. Stricter environmental regulations of emissions from coal-fired electric generating plants could increase the costs of using coal thereby reducing demand for coal as a fuel source, the volume of our coal sales and price. Stricter regulations could make coal a less attractive fuel alternative in the planning and building of utility power plants in the future.

For example, in order to meet the federal Clean Air Act limits for sulfur dioxide emissions from electric power plants, coal users will need to install scrubbers, use sulfur dioxide emission allowances (some of which they may purchase), or switch to other fuels. Each option has limitations. Lower sulfur coal may be more costly to purchase on an energy basis than higher sulfur coal depending on mining and transportation costs. The cost of installing scrubbers is significant and emission allowances may become more expensive as their availability declines. Switching to other fuels may require expensive modification of existing plants. Because higher sulfur coal currently accounts for a significant portion of our sales, the extent to which power generators switch to alternative fuel could materially affect us if we cannot offset the cost of sulfur removal by lowering the delivered costs of our higher sulfur coals on an energy equivalent basis.

Proposed reductions in emissions of mercury, sulfur dioxides, nitrogen oxides, particulate matter or greenhouse gases may require the installation of additional costly control technology or the implementation of other measures, including trading of emission allowances and switching to other fuels. For example, in 2005 the Environmental Protection Agency proposed separate regulations to establish mercury emission limits nationwide and to reduce the interstate transport of fine particulate matter and ozone through reductions in sulfur dioxides and nitrogen oxides throughout the eastern United States. The Environmental Protection Agency continues to require reduction of nitrogen oxide emissions in a number of eastern states and the District of Columbia and will require reduction of particulate matter emissions over the next several years for areas that do not meet air quality standards for fine particulates. In addition, Congress and several states may consider legislation to further control air emissions of multiple pollutants from electric generating facilities and other large emitters. Any new or proposed reductions will make it more costly to operate coal-fired plants and could make coal a less attractive fuel alternative to the planning and building of utility power plants in the future. To the extent that any new or proposed requirements affect our customers, this could adversely affect our operations and results.

CONSOL Energy may not be able to produce sufficient amounts of coal to fulfill our customers requirements, which could harm our relationships with customers.

CONSOL Energy may not be able to produce sufficient amounts of coal to meet customer demand, including amounts that we are required to deliver under long-term contracts. CONSOL Energy s inability to satisfy contractual obligations could result in our customers initiating claims against us.

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

We compete in international markets against coal produced in other countries. Coal is sold internationally in U. S. dollars. As a result, mining costs in competing producing countries may be reduced in U.S. 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.

Table of Contents

Coal mining is subject to conditions or events beyond CONSOL Energy s control, which could cause our financial results to deteriorate.

CONSOL Energy s coal mining operations are predominantly underground mines. These mines are subject to conditions or events beyond CONSOL Energy s control that could disrupt operations and affect production and the cost of mining at particular mines for varying lengths of time. These conditions or events may have a significant impact on our operating results. Conditions or events have included:

- variations in thickness of the layer, or seam, of coal;
- amounts of rock and other natural materials intruding into the coal seam and other geological conditions that could affect the stability of the roof and the side walls of the mine;
- equipment failures or repairs;
- fires and other accidents; and
- weather conditions.

Our mining operations consume significant quantities of commodities, the price of which is determined by international markets. If commodity prices increase significantly or rapidly, it could impact our cost of production.

Coal mines consume large quantities of commodities such as steel, copper, rubber products and liquid fuels. Some commodities, such as steel, are needed to comply with roof control plans required by regulation. The prices we pay for these products are strongly impacted by the global commodities market. A rapid or significant increase in cost of some commodities could impact our mining costs because we have a limited ability to negotiate lower prices, and, in some cases, do not have a ready substitute for these commodities.

CONSOL Energy must obtain for mining and drilling operations, governmental permits and approvals which can be a costly and time consuming process and can result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of exploration or production operations. For example, CONSOL Energy often is required to prepare and present to federal, state and local authorities data pertaining to the effect or impact that proposed exploration for or production of coal may have on the environment. Further, the public has the right to comment on and otherwise participate in the permitting process, including through administrative appeals of permits and possibly further appeals in the courts. Accordingly, the permits CONSOL Energy needs may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements which restrict our ability to conduct our mining or gas operations or to do so profitably.

Proposals to regulate greenhouse gas emissions could impact the market for our fossil fuels, increase our costs, and reduce the value of our coal and gas assets.

Numerous proposals have been made at the international, national, regional, and state levels of government that are intended to limit emissions of greenhouse gas (GHGs), such as carbon dioxide and methane. Combustion of fossil fuels, such as the coal and gas we produce, results in the creation of carbon dioxide that is currently emitted into the atmosphere by coal and gas end users. Several states have already adopted measures requiring reduction of GHGs within state boundaries. If comprehensive regulations focusing on GHGs emission reductions were to be enacted by the United States or additional individuals states, it may adversely affect the use of and demand for fossil fuels, particularly coal. Further regulation of GHGs could occur in the United States pursuant to treaty obligations, regulation under the clean air act, or regulation under state law. In 2007, the U.S. Supreme Court held in Massachusetts v. Environmental Protection Agency (EPA), that EPA had authority to regulate GHG s under the Clean Air Act, (the Act), reversing the EPA s interpretation of the Act. This decision could lead to federal regulation of GHGs under the existing clean air act of coal-fired electric generation stations, which could adversely affect demand for our products.

In addition, many of our underground coal mines vent methane into the atmosphere for safety reasons. Coalbed methane enhances the greenhouse gas effect to a greater degree than carbon dioxide. If regulation of GHG emissions does not exempt coal mine methane, we may have to curtail production, pay higher taxes, or incur costs to purchase allowances that permit us to continue operations as they now exist.

Our gas operations primarily produce gas by capturing coalbed methane. If the coalbed methane is not extracted from the coal seam prior to mining, much of this gas would be liberated to the atmosphere when the coal is mined. The coalbed methane we capture is recorded, on a voluntarily basis, with the U.S Department of Energy. We have recorded the amounts we have captured since the early 1900 s. If regulation of GHGs does not give us credit for methane that would otherwise be released into the atmosphere, any value associated with our historical or future credits would be reduced or eliminated.

In addition, on February 4, 2008 three of Wall Street s largest investment banks announced that they had adopted climate change guidelines for lenders to evaluate carbon risks in the financing of utility power plants which may make it more difficult for utilities to obtain financing for coal-fired plants.

Government laws, regulations and other legal requirements relating to protection of the environment, health and safety matters and others that govern our business increase our costs of doing business for both coal and gas, and may restrict our operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local, as well as foreign authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and wastes, the cleanup of contaminated sites, groundwater quality and availability, plant and wildlife protection, reclamation and restoration of mining or drilling properties after mining or drilling is completed, the installation of various safety equipment in our mines, control of surface subsidence from underground mining and work practices related to employee health and safety. Complying with these requirements, including the terms of our permits, has had, and will continue to have, a significant effect on our costs of operations and competitive position. In addition, we could incur substantial costs, including clean up costs, fines and civil or criminal sanctions and third party damage claims for personal injury, property damage, wrongful death, or exposure to hazardous substances, as a result of violations of or liabilities under environmental and health and safety laws.

For example, the federal Clean Water Act and corresponding state laws affect coal mining and gas operations by imposing restrictions on discharges into regulated surface waters. Permits requiring regular monitoring and compliance with effluent limitations and reporting requirements govern the discharge of pollutants into regulated waters. In combination with existing requirements, new requirements under the Clean Water Act and corresponding state laws (including those relating to protection of impaired waters so designated by individual states through the use of new effluent limitations known as Total Maximum Daily Load (TMDL) limits; anti-degradation regulations which protect state designated high quality/exceptional use streams by restricting or prohibiting discharges which result in degradation; and requirements to treat discharges from coal mining properties for non-traditional pollutants, such as chlorides and selenium; and protecting streams, wetlands, other regulated water sources and associated riparian lands from the surface impacts of underground mining), may cause CONSOL Energy to incur significant additional costs that could adversely affect our operating results, financial condition and cash flows or may prevent us from being able to mine portions of our reserves. In addition, CONSOL Energy incurs and will continue to incur significant costs associated with the investigation and remediation of environmental contamination under the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund) and similar state statutes and has been named as a potentially responsible party at Superfund sites in the past.

Additionally, the gas industry is subject to extensive legislation and regulation, which is under constant review for amendment or expansion. Any changes may affect, among other things, the pricing or marketing of gas production. State and local authorities regulate various aspects of gas drilling and production activities,

38

including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, market sharing and well site restoration. If we fail to comply with statutes and regulations, we may be subject to substantial penalties, which would decrease our profitability.

Our mines are subject to stringent federal and state safety regulations that increase our cost of doing business at active operations, and may place restrictions on our methods of operation. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shut down based on safety considerations.

Stringent health and safety standards were imposed by federal legislation when the Federal Coal Mine Health and Safety Act of 1969 was adopted. The Federal Coal Mine Safety and Health Act of 1977 expanded the enforcement of safety and health standards of the Coal Mine Health and Safety Act of 1969 and imposed safety and health standards on all (non-coal as well as coal) mining operations. Regulations are comprehensive and affect numerous aspects of mining operations, including training of mine personnel, mining procedures, the equipment used in mine emergency procedures, mine plans and other matters. Several mining accidents at our competitors mines that resulted in fatalities in early 2006 led to adoption of additional safety regulations by the Mine Safety and Health Administration and the adoption in June 2006 of the Mine Improvement and New Emergency Response Act of 2006 (the MINER Act). The additional requirements of the MINER Act and implementing federal regulations include, among other things, expanded emergency response plans, providing additional quantities of breathable air for emergencies, installation of refuge chambers in underground coal mines, installation of two-way communications and tracking systems for underground coal mines, new standards for sealing mined out areas of underground coal mines, more available mine rescue teams and enhanced training for emergencies. Most states in which CONSOL Energy operates have programs for mine safety and health regulation and enforcement. We believe that the combination of federal and state safety and health regulations in the coal mining industry is, perhaps, the most comprehensive system for protection of employee safety and health affecting any industry. Most aspects of mine operations, particularly underground mine operations, are subject to extensive regulation. The various requirements mandated by law or regulation can have a significant effect on operating costs and place restrictions on our methods of operations. In addition, government inspectors under certain circumstances, have the ability to order our operation to be shut down based on safety considerations.

CONSOL Energy has reclamation and mine closure obligations. If the assumptions underlying our accruals are inaccurate, we could be required to expend greater amounts than anticipated.

The Surface Mining Control and Reclamation Act establishes operational, reclamation and closure standards for all aspects of surface mining as well as most aspects of deep mining. CONSOL Energy accrues for the costs of current mine disturbance and of final mine closure, including the cost of treating mine water discharge where necessary. Estimates of our total reclamation and mine-closing liabilities, which are based upon permit requirements and our experience were approximately $482 million at December 31, 2007. The amounts recorded are dependent upon a number of variables, including the estimated future retirement costs, estimated proven reserves, assumptions involving profit margins, inflation rates, and the assumed credit-adjusted risk-free interest rates. Furthermore, these obligations are unfunded. If these accruals are insufficient or our liability in a particular year is greater than currently anticipated, our future operating results could be adversely affected.

CONSOL Energy faces uncertainties in estimating our economically recoverable coal reserves, and inaccuracies in our estimates could result in lower than expected revenues, higher than expected costs and decreased profitability.

There are 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 our staff.

Table of Contents

Some of the factors and assumptions which impact economically recoverable reserve estimates include:

- geological conditions;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations and taxes by governmental agencies;
- assumptions governing future prices; and
- future operating costs, including cost of materials.

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, revenues and expenditures with respect to our reserves will likely vary from estimates, and these variances may be material. As a result, our estimates may not accurately reflect our actual reserves.

We do not insure against all potential operating risks. We may incur losses and be subject to liability claims as a result of our operations.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to renew our existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all. Although we maintain insurance at levels we believe are appropriate and consistent with industry practice, we are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition, results of operations and cash flows.

Fairmont Supply Company, a subsidiary of CONSOL Energy, is a co-defendant in various asbestos litigation cases which could result in making payments in the future that are material.

One of our subsidiaries, Fairmont Supply Company (Fairmont), which distributes industrial supplies, currently is named as a defendant in approximately 25,000 asbestos claims in state courts in Pennsylvania, Ohio, West Virginia, Maryland, Mississippi and New Jersey. Because a very small percentage of products manufactured by third parties and supplied by Fairmont in the past may have contained asbestos and many of the pending claims are part of mass complaints filed by hundreds of plaintiffs against a hundred or more defendants, it has been difficult for Fairmont to determine how many of the cases actually involve valid claims or plaintiffs who were actually exposed to asbestos-containing products supplied by Fairmont. In addition, while Fairmont may be entitled to indemnity or contribution in certain jurisdictions from manufacturers of identified products, the availability of such indemnity or contribution is unclear at this time and, in recent years, some of the manufacturers named as defendants in these actions have sought protection from these claims under bankruptcy laws. Fairmont has no insurance coverage with respect to these asbestos cases. For year ended December 31, 2007, payments by Fairmont with respect to asbestos cases have not been material. Our current estimates related to these asbestos claims, individually and in the aggregate, are immaterial to the financial position, results of operations and cash flows of CONSOL Energy. However, it is reasonably possible that payments in the future with respect to pending or future asbestos cases may be material to the financial position, results of operations or cash flows of CONSOL Energy.

Table of Contents

CONSOL and its subsidiaries are subject to various legal proceedings, which may have a material effect on our business.

We are party to a number of legal proceedings incident to normal business activities. There is the potential that an individual matter or the aggregation of many matters could have an adverse effect on our cash flows, results of operations or financial position. See Note 26 in the Note to the Audited Consolidated Financial Statements for further discussion.

CONSOL Energy has obligations for long-term employee benefits for which we accrue based upon assumptions which, if inaccurate, could result in CONSOL Energy being required to expense greater amounts than anticipated.

CONSOL Energy provides various long-term employee benefits to inactive and retired employees. We accrue amounts for these obligations. At December 31, 2007, the current and non-current portions of these obligations, included:

- post retirement medical and life insurance ($2.5 billion);
- coal workers black lung benefits ($182.9 million);
- salaried retirement benefits ($70.2 million); and
- workers compensation ($162.1 million).

However, if our assumptions are inaccurate, we could be required to expend greater amounts than anticipated. These obligations are unfunded, except for salaried retirement benefits, of which approximately 90% was funded at December 31, 2007. In addition, several states in which we operate consider changes in workers compensation and black lung laws from time to time. Such changes, if enacted, could increase our benefit expense.

Due to our participation in multi-employer pension and benefit plans, we have exposure under those plans that extend beyond what our obligation would be with respect to our employees.

We are obligated to contribute to multi-employer defined benefit plans for UMWA retirees which provides pension, medical and death benefits. In the event of a partial or complete withdrawal by us from any plan which is underfunded, we would be liable for a proportionate share of such plan s unfunded vested benefits. Based on the limited information available from plan administrators, which we cannot independently validate, we believe that our portion of the contingent liability in the case of a full withdrawal or termination could be material to our financial position and results of operations. In the event that any other contributing employer withdraws from any plan which is underfunded, and such employer (or any member in its controlled group) cannot satisfy their obligations under the plan at the time of withdrawal, then we, along with the other remaining contributing employers, would be liable for our proportionate share of such plan s unfunded vested benefits.

In addition, if a multi-employer pension plan fails to satisfy the minimum funding requirements, the Internal Revenue Service, pursuant to Section 4971 of the Internal Revenue Code (the Code) will impose an excise tax of 5% on the amount of the accumulated funding deficiency. Under Section 413(c)(5) of the Code, the liability of each contributing employer, including us, will be determined in part by each employer s additional contributions in order to reduce the deficiency to zero, which may, along with the payment of the excise tax, have a material adverse impact on our financial results.

Table of Contents

If lump sum payments made to retiring salaried employees pursuant to CONSOL Energy s defined benefit pension plan exceed the total of the service cost and the interest cost in a plan year, CONSOL Energy would need to make an adjustment to operating results equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum payment in that year, which may result in an adjustment that could materially reduce operating results.

CONSOL Energy s defined benefit pension plan for salaried employees allows such employees to receive a lump-sum distribution for benefits earned up through December 31, 2005 in lieu of annual payments when they retire from CONSOL Energy. Statement of Financial Accounting Standards No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans for the Terminations Benefits, requires that if the lump-sum distributions made for a plan year, which currently for CONSOL Energy is October 1 to September 30, exceed the total of the service cost and interest cost for the plan year, CONSOL Energy would need to recognize for that year s results of operations an adjustment equaling the unrecognized actuarial gain or loss resulting from each individual who received a lump sum in that year. Lump sum payments in CONSOL Energy s non-qualified pension plan exceeded the total of the service cost and the interest cost in the plan year ended September 30, 2007. This resulted in expense of $2.7 million in the year ended December 31, 2007. If lump sum payments again exceed the total of the service cost and the interest cost, the adjustment could materially reduce operating results.

Various federal or state laws and regulations require CONSOL Energy to obtain surety bonds or to provide other assurance of payment for certain of our long-term liabilities including mine closure or reclamation costs, workers compensation, coal workers black lung and other post employment benefits.

Federal and state laws and regulations require us to obtain surety bonds or provide other assurances to secure payment of certain long-term obligations including mine closure or reclamation costs, water treatment costs, federal and state workers compensation costs, and other miscellaneous obligations. The requirements and amounts of security are not fixed and can vary from year to year. It has become increasingly difficult for us to secure new surety bonds or renew such bonds without posting collateral. CONSOL Energy has satisfied our obligations under these statutes and regulations by providing letters of credit or other assurances of payment. The issuance of letters of credit under our bank credit facility reduces amounts that we can borrow under our bank credit facility for other purposes.

Acquisitions that we have completed, as well as acquisitions that we may undertake in the future, involve a number of risks, any of which could cause us not to realize the anticipated benefits.

We have completed several acquisitions and investments in the past. We continually seek to expand our operations and coal and gas reserves through acquisitions. If we are unable to successfully integrate the companies, businesses or properties we acquire, our profitability may decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Acquisition transactions involve various inherent risks, including:

- 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 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;

Problems that could arise from the integration of the acquired business; and

Unanticipated changes in business, industry or general economic conditions that affect the assumptions underlying our rationale for pursuing the acquisition.

Table of Contents

CONSOL Energy s rights plan may have anti-takeover effects that could prevent a change of control.

On December 19, 2003, CONSOL Energy adopted a rights plan which, in certain circumstances, including a person or group acquiring, or the commencement of a tender or exchange offer that would result in a person or group acquiring, beneficial ownership of more than 15% of the outstanding shares of CONSOL Energy common stock, would entitle each right holder to receive, upon exercise of the right, shares of CONSOL Energy common stock having a value equal to twice the right exercise price. For example, at an exercise price of $80 per right, each right not otherwise voided would entitle its holders to purchase $160 worth of shares of CONSOL Energy common stock for $80. Assuming that shares of CONSOL Energy common stock had a per share value of $16 at such time, the holder of each right would be entitled to purchase ten shares of CONSOL Energy common stock for $80, or a price of $8 per share, one half its then market price. This and other provisions of CONSOL Energy s rights plan could make it more difficult for a third party to acquire CONSOL Energy, which could hinder stockholders ability to receive a premium for CONSOL Energy stock over the prevailing market prices.

CONSOL Energy faces uncertainties in estimating proved recoverable gas reserves, and inaccuracies in our estimates could result in lower than expected reserve quantities and a lower present value of our reserves.

Natural gas reserve engineering requires subjective estimates of underground accumulations of natural gas and assumptions concerning future natural gas prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and timing of development expenditures may be incorrect. We have in the past retained the services of independent petroleum engineers to prepare reports of our proved reserves. Over time, material changes to reserve estimates may be made, taking into account the results of actual drilling, testing, and production. Also, we make certain assumptions regarding future natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of our reserves, the economically recoverable quantities of natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of gas we ultimately recover being different from reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs. However, actual future net cash flows from our gas and oil properties also will be affected by factors such as:

- geological conditions;
- changes in governmental regulations and taxation;
- assumptions governing future prices;
- the amount and timing of actual production;
- future operating costs; and

capital costs of drilling new wells.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Table of Contents

Our gas exploration and development activities may not be commercially successful.

The exploration for and production of gas involves risks. The cost of drilling, completing and operating wells for coalbed methane or other gas is often uncertain, and a number of factors can delay or prevent drilling operations or production, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in geologic formations;
- equipment failures or repairs;
- fires or other accidents;
- adverse weather conditions;
- reductions in natural gas prices;
- pipeline ruptures; and
- unavailability or high cost of drilling rigs, other field services and equipment.

Our future drilling activities may not be successful, and our drilling success rate could decline. Unsuccessful drilling activities could result in higher costs without any corresponding revenues.

We have a limited operating history in certain of our gas operating areas, and our increased focus on new development projects in these and other unexplored areas increases the risks inherent in our gas and oil activities.

In 2008 and beyond we plan to conduct testing and development activities in areas where we have little or no proved reserves, such as certain areas in Pennsylvania and Kentucky. These exploration, drilling and production activities will be subject to many risks, including the risk that coalbed methane or natural gas is not present in sufficient quantities in the coal seam or target strata, or that sufficient permeability does not exist for gas to be produced economically. We have invested in property, and will continue to invest in property, including undeveloped leasehold acreage, that we believe will result in projects that will add value over time. Drilling for coalbed methane, natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. We cannot be certain that the wells we drill in these new areas will be productive or that we will recover all or any portion of our investments.

Our gas business depends on transportation facilities owned by others. Disruption of, capacity constraints in, or proximity to pipeline systems could limit sales of our gas.

We transport our gas to market by utilizing pipelines owned by others. If pipelines do not exist near our producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, our gas sales could be limited, reducing our profitability. If we cannot access pipeline transportation, we may have to reduce our production of gas or vent our produced gas to the atmosphere because we do not have facilities to store excess inventory. If our sales are reduced because of transportation constraints, our revenues will be reduced, which will also increase our unit costs. If we cannot obtain transportation capacity and we do not have the ability to store gas, we may have to reduce production. If pipeline quality tariffs change, we might be required to install additional processing equipment which could increase our costs. The pipeline could curtail our flows until the gas delivered to the pipeline is in compliance.

Table of Contents

Increased gas industry activity may create shortages of field services, equipment and personnel, which may increase our costs and may limit our ability to drill and produce gas.

Due to current industry demands, well service providers and related equipment are in short supply. The demand for qualified and experienced field personnel to drill wells and conduct field operations, including, geologists, geophysicists, engineers and other professionals, in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These shortages may lead to escalating prices, the possibility of poor services, ineffective drilling operations and personnel injuries. Such pressures will likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. We believe that these shortages could continue. In addition, the costs and delivery time of equipment and supplies are substantially greater in periods of peak demand. Accordingly, we cannot assure that we will be able to obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms and we may experience shortages of, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services in the future. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

Unless we replace our natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition, results of operations and cash flows.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2007, production is expected to decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

We may incur additional costs and delays to produce gas because we have to acquire additional property rights to perfect our title to the gas estate.

Some of the gas rights we believe we control are in areas where we have not yet done any exploratory or production drilling. Most of these properties were acquired primarily for the coal rights, and, in many cases were acquired years ago. While chain of title work for the coal estate was generally fully developed, in many cases, the gas estate title work is less robust. Our practice is to perform a thorough title examination of the gas estate before we commence drilling activities and to acquire any additional rights needed to perfect our ownership of the gas estate for development and production purposes. We may incur substantial costs to acquire these additional property rights and the acquisition of the necessary rights may not be feasible in some cases. Our inability to obtain these rights may adversely impact our ability to develop these properties. Some states permit us to produce the gas without perfected ownership under an administrative process known as forced pooling, which requires us to give notice to all potential claimants and pay royalties into escrow until the undetermined rights are resolved. As a result, we may have to pay royalties to produce gas on acreage that we control and these costs may be material. Further, the forced pooling process is time consuming and may delay our drilling program in the affected areas. In addition, although we believe we have the right to extract and produce coalbed methane from locations where we possess rights to coal, in some cases we may not possess these rights. If we are unable in such cases to obtain those rights from their owners, we will not enjoy the rights to develop coalbed methane with our mining of coal. Our failure to obtain these rights may adversely impact our ability in the future to increase production and reserves. For example, we have substantial acreage in West Virginia for which we have not reviewed the title to determine what, if any, additional rights would be needed to produce coalbed methane from these locations or the feasibility of obtaining these rights.

Table of Contents

Currently the vast majority of our gas producing properties are located in three counties in Virginia, making us vulnerable to risks associated with having our gas production concentrated in one area.

The vast majority of our gas producing properties are geographically concentrated in three counties in Virginia. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of gas production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters or interruption of transportation of natural gas produced from the wells in this basin or other events which impact this area.

Other persons could have ownership rights in our advanced gas extraction techniques which could force us to cease using those techniques or pay royalties.

Although we believe that we hold sufficient rights to all of our advanced gas extraction techniques, other persons could contest our rights and claim ownership of one or more of our advanced techniques for extracting coalbed methane. For example, a third party has asserted that several of our drilling techniques infringed several patents that they hold. A successful challenge to one or more of our advanced extraction techniques could adversely impact our financial performance and results of operation. We might have to pay a royalty which would increase our production costs or cease using that technique which could raise our production costs or decrease our production of coalbed methane. In addition, we could incur substantial costs in defending patent infringement claims, obtaining patent licenses, engaging in interference and opposition proceedings or other challenges to our patent rights or intellectual property rights made by third parties or in bringing such proceedings.

The coal beds and other strata from which we produce methane gas frequently contain water and the gas often contains impurities, both of which may hamper our ability to produce gas in commercial quantities or economically.

Coal beds and other strata frequently contain water that must be removed in order for the gas to detach from the coal and flow to the well bore. Our ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not we can produce gas in commercial quantities. The cost of water disposal may affect our profitability. Further, a substantial amount of our gas needs to be processed in order to make it salable to our intended customers. At times, the cost of processing this gas relative to the quantity of gas from a particular well, or group of wells, may outweigh the economic benefit of selling that gas, and our profitability may decrease due to the reduced production and sale of gas.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To manage our exposure to fluctuations in the price of natural gas, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2007, we had hedges on approximately 24.5 billion cubic feet of our targeted 2008 natural gas production. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected, the counterparties to our futures contracts fail to perform the contracts, or if our gas hedges would no longer qualify for hedge accounting, we will be required to mark them to market. This may result in more volatility in our income in the future periods.

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

None.

Table of Contents

Item 2. ***Properties.***

See Coal Operations and Gas Operations in Item 1 of this 10-K for a description of CONSOL Energy s properties.

Item 3. ***Legal Proceedings.***

The first through eighteenth paragraphs of Note 26 of the Notes to the Audited Consolidated Financial Statements included as Item 8 in Part II of this Form 10-K are incorporated herein by reference.

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

None.

Table of Contents

PART II

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

Common Stock Market Prices and Dividends

Our common stock is listed on the New York Stock Exchange under the symbol CNX. The following table sets forth for the periods indicated the range of high and low sales prices per share of our common stock as reported on the New York Stock Exchange and the cash dividends declared on the common stock for the periods indicated. Information presented reflects the 2 for 1 stock split that occurred in May 2006.

	High	Low	Dividends
Year Period Ended December 31, 2007:			
Quarter Ended March 31, 2007	$ 39.90	$ 29.15	$ 0.07
Quarter Ended June 30, 2007	$ 49.85	$ 38.37	$ 0.07
Quarter Ended September 30, 2007	$ 50.21	$ 34.37	$ 0.07
Quarter Ended December 31, 2007	$ 74.18	$ 45.04	$ 0.10
Year Period Ended December 31, 2006:			
Quarter Ended March 31, 2006	$ 37.70	$ 30.00	$ 0.07
Quarter Ended June 30, 2006	$ 49.09	$ 35.12	$ 0.07
Quarter Ended September 30, 2006	$ 48.90	$ 28.07	$ 0.07
Quarter Ended December 31, 2006	$ 38.71	$ 28.69	$ 0.07

As of January 30, 2008, there were approximately 71,800 holders of record of our common stock. The computation of the approximate number of shareholders is based upon a broker search.

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on the common stock of CONSOL Energy to the cumulative shareholder return for the same period of a peer group and the Standard & Poor s 500 Stock Index. The peer group has changed from last year in order to be consistent with the peer group that is utilized for executive compensation benchmarking. The peer group is comprised of CONSOL Energy, Alliance Resource Partners, Alpha Natural Resources, Inc., Anadarko Petroleum Corp., Apache Corp., Cabot Oil & Gas Corp., Callon Petroleum Co., Comstock Resources, Inc., Denbury Resources, Inc., Devon Energy Corp., Encana Corp., EOG Resources, Inc., Foundation Coal Holdings, Inc., International Coal Group, Inc., James River Coal Co., Massey Energy Co., Newfield Exploration Co., Nexen Inc., Noble Energy Inc., Peabody Energy Corp., Penn Virginia Corp., Pioneer Natural Resources Co., Rio Tinto PLC (ADR), St. Mary Land & Exploration, Stone Energy Corp., Ultra Petroleum Corp., and Westmorland Coal Co. The previous peer group included CONSOL Energy, Allegheny Energy, Inc., Alpha Natural Resources, Inc., Apache Corp., Arch Coal, Inc., Barrick Gold Corp., Equitable Resources, Inc., Foundation Coal Holdings, Inc., Massey Energy Co., Peabody Energy Corp., and Vectren Corp. The graph assumes that the value of the investment in CONSOL Energy common stock and each index was $100 at December 31, 2002. The graph also assumes that all dividends were reinvested and that the investments were held through December 31, 2007.

	2002	2003	2004	2005	2006	2007
CONSOL Energy Inc.	100.0	153.1	213.8	273.9	273.3	396.9
Peer Group	100.0	139.3	171.4	229.0	231.4	293.0
Previous Peer Group	100.0	140.4	168.6	208.8	210.4	261.1
S&P 500 Stock Index	100.0	128.4	139.1	143.9	159.5	164.9

48

Table of Contents

Cumulative Total Shareholder Return Among CONSOL Energy Inc., Peer Group and

S&P 500 Stock Index

The above information is being furnished pursuant to Regulation S-K, Item 201 (e) (Performance Graph).

On January 30, 2008, CONSOL Energy s board of directors declared a dividend of $0.10 per share, payable on February 22, 2008, to shareholders of record on February 7, 2008.

The declaration and payment of dividends by CONSOL Energy is subject to the discretion of CONSOL Energy s Board of Directors, and no assurance can be given that CONSOL Energy will pay dividends in the future. CONSOL Energy s Board of Directors determines whether dividends will be paid quarterly. The determination to pay dividends will depend upon, among other things, general business conditions, CONSOL Energy s financial results, contractual and legal restrictions regarding the payment of dividends by CONSOL Energy, planned investments by CONSOL Energy and such other factors as the board of directors deems relevant.

Table of Contents

On December 21, 2005, CONSOL Energy s Board of Directors announced a share repurchase program of up to $300 million of the company s common stock during a 24-month period beginning January 1, 2006 and ending December 31, 2007. The program was not renewed. We repurchased common stock in each of the quarters of 2007 and 2006 as follows:

Period	Total Number of Shares Purchased	Average Price Paid Per Share
January 1, 2007 March 31, 2007	730,000	$ 35.05
April 1, 2007 June 30, 2007	1,357,800	$ 39.80
July 1, 2007 September 30, 2007		$
October 1, 2007 December 31, 2007		$
Total 2007 Purchases	2,087,800	$ 38.14
January 1, 2006 March 31, 2006	2,391,800	$ 32.22
April 1, 2006 June 30, 2006	158,000	$ 41.28
July 1, 2006 September 30, 2006	965,000	$ 33.97
October 2, 2006 December 31, 2006		$
Total 2006 Purchases	3,514,800	$ 33.11
Total Purchases Under Program	5,602,600	$ 34.98

See Part III, Item 12. Security ownership of Certain Beneficial Owners and Management and Related Stockholders Matters for information relating to CONSOL Energy s equity compensation plans.

Item 6. ***Selected Financial Data.***

The following table presents our selected consolidated financial and operating data for, and as of the end of, each of the periods indicated. The selected consolidated financial data for, and as of the end of, each of the years ended December 31, 2007, 2006, 2005, 2004 and 2003 are derived from our audited consolidated financial statements. The selected consolidated financial and operating data are not necessarily indicative of the results that may be expected for any future period. The selected consolidated financial and operating data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the financial statements and related notes included in this report.

Table of Contents

STATEMENT OF INCOME DATA

(In thousands except per share data)

	Year Ended December 31, 2007	2006	2005	2004	2003
Revenue and Other Income:					
Sales Outside and Related Party	$ 3,324,346	$ 3,286,522	$ 2,935,682	$ 2,425,206	$ 2,009,880
Sales Purchased Gas	7,628	43,973	275,148	112,005	
Sales Gas Royalty Interests	46,586	51,054	45,351	41,858	32,442
Freight Outside and Related Party(A)	186,909	162,761	119,811	110,175	114,582
Other Income	196,728	170,861	107,131	87,505	65,562
Gain on Sale of 18.5% interest in CNX Gas			327,326		
Total Revenue and Other Income	3,762,197	3,715,171	3,810,449	2,776,749	2,222,466
Costs:					
Cost of Goods Sold and Other Operating Charges (exclusive of depreciation, depletion and amortization shown below)	2,351,507	2,249,776	2,122,259	1,855,033	1,599,816
Purchased Gas Costs	7,162	44,843	278,720	113,063	
Gas Royalty Interests Costs	39,921	41,879	36,501	32,914	24,200
Freight Expense	186,909	162,761	119,811	110,175	114,582
Selling, General and Administrative Expense	108,664	91,150	80,700	72,870	77,571
Depreciation, Depletion and Amortization	324,715	296,237	261,851	280,397	242,152
Interest Expense	30,851	25,066	27,317	31,429	34,451
Taxes Other Than Income	283,511	252,539	228,606	198,305	159,595
Restructuring Costs					3,606
Total Costs	3,333,240	3,164,251	3,155,765	2,694,186	2,255,973
Earnings (Loss) Before Income Taxes, Minority Interest and Cumulative Effect of Change in Accounting Principle	428,957	550,920	654,684	82,563	(33,507)
Income Taxes (Benefits)	136,137	112,430	64,339	(32,646)	(20,941)
Earnings (Loss) Before Minority Interest and Cumulative Effect of Change in Accounting principle	292,820	438,490	590,345	115,209	(12,566)
Minority Interest	(25,038)	(29,608)	(9,484)		
Cumulative Effect of Change in Accounting for Workers Compensation Liability, Net of Income Taxes of $53,080				83,373	
Cumulative Effect of Change in Accounting for Mine Closing, Reclamation and Gas Well Closing Costs, Net of Income Taxes of $3,035					4,768
Net Income (Loss)	$ 267,782	$ 408,882	$ 580,861	$ 198,582	$ (7,798)
Earnings (Loss) Per Share From Continuing Operations					
Basic	$ 1.47	$ 2.23	$ 3.17	$ 0.64	$ (0.08)
Dilutive	$ 1.45	$ 2.20	$ 3.13	$ 0.63	$ (0.08)
Earnings (Loss) Per Share From Net Income					
Basic(B)	$ 1.47	$ 2.23	$ 3.17	$ 1.10	$ (0.05)
Dilutive(B)	$ 1.45	$ 2.20	$ 3.13	$ 1.09	$ (0.05)
Weighted Average Number of Common Shares Outstanding:					
Basic(C)	182,050,627	183,354,732	183,489,908	180,461,386	163,465,178

Dilutive(C)	184,149,751	185,638,106	185,534,980	182,399,890	163,465,178
Dividend Per Share	$ 0.31	$ 0.28	$ 0.28	$ 0.28	$ 0.28

Table of Contents

BALANCE SHEET DATA

(In thousands)

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Working (deficiency) capital	$ (333,242)	$ 174,372	$ 194,578	$ (243,275)	$ (358,459)
Total assets	6,208,090	5,663,332	5,071,963	4,195,611	4,318,978
Short-term debt	247,500			5,060	68,760
Long-term debt (including current portion)	507,208	552,263	442,996	429,645	495,242
Total deferred credits and other liabilities	3,325,231	3,228,653	2,726,563	2,582,318	2,757,130
Stockholders equity	1,214,419	1,066,151	1,025,356	469,021	290,637

OTHER OPERATING DATA

(Unaudited)

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Coal:					
Tons sold (in thousands)(D)(E)	65,462	68,920	70,401	69,537	63,962
Tons produced (in thousands)(E)	64,617	67,432	69,126	67,745	60,388
Productivity (tons per manday)(E)	41.29	38.41	37.95	40.51	41.26
Average production cost ($ per ton produced)(E)	$ 33.68	$ 32.53	$ 30.06	$ 27.54	$ 26.24
Average sales price of tons produced ($ per ton produced)(E)	$ 40.60	$ 38.99	$ 35.61	$ 30.06	$ 27.61
Recoverable coal reserves (tons in millions)(E)(F)	4,526	4,272	4,546	4,509	4,158
Number of active mining complexes (at period end)	15	14	17	16	15
Gas:					
Net sales volume produced (in billion cubic feet)(E)	58.25	56.14	48.39	48.56	44.46
Average sale price ($ per mcf)(E)(G)	$ 7.20	$ 7.04	$ 5.90	$ 4.90	$ 4.03
Average cost ($ per mcf)(E)	$ 3.37	$ 2.88	$ 2.69	$ 2.45	$ 2.35
Proved reserves (in billion cubic feet)(E)(H)	1,343	1,265	1,130	1,045	1,004

CASH FLOW STATEMENT DATA

(In thousands)

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Net cash provided by operating activities	$ 684,033	$ 664,547	$ 409,086	$ 358,091	$ 381,127
Net cash used in investing activities	(972,104)	(661,546)	(74,413)	(400,542)	(204,614)
Net cash provided by (used in) financing activities	105,839	(119,758)	(455)	42,360	(181,517)

OTHER FINANCIAL DATA

(Unaudited)

(In thousands)

Capital expenditures	$ 1,039,838	$ 690,546	$ 532,796	$ 420,965	$ 300,848
EBIT(I)	421,978	531,009	664,451	108,616	(5,354)
EBITDA(I)	746,693	827,246	926,302	389,013	236,798
Ratio of earnings to fixed charges(J)	7.48	11.36	15.95	2.76	

(A) See Note 27 of Notes to the Audited Consolidated Financial Statements for sales and freight by operating segment.

(B) Basic earnings per share are computed using weighted average shares outstanding. Differences in the weighted average number of shares outstanding for purposes of computing dilutive earnings per share are due to the inclusion of the weighted average dilutive effect of employee and non-employee director stock options granted, totaling 2,099,124 shares, 2,283,374 shares, 2,045,072 shares, 1,938,504 shares and no shares for the year ended December 31, 2007, 2006, 2005, 2004 and 2003, respectively.

(C) On May 4, 2006, CONSOL Energy s Board of Directors declared a two-for-one stock split of the common stock. The stock split resulted in the issuance of approximately 92.5 million additional shares of common stock. Shares and earnings per share for all periods presented are reflected on a post-split basis.

(D) Includes sales of coal produced by CONSOL Energy and purchased from third parties. Of the tons sold, CONSOL Energy purchased the following amount from third parties: 0.5 million tons in the year ended December 31, 2007, 1.3 million tons in the year ended December 31, 2006, 1.5 million tons in year ended December 31, 2005, 2.1 million tons in the year ended December 31, 2004 and 2.5 million tons in the year ended December 31, 2003. Also, includes 0.8 million and 1.1 million sales tons for the year ended December 31, 2007 and 2006, respectively, which is 100% of tons sold by our fully consolidated, 49% owned variable interest entity. Sales of coal produced by equity affiliates were 0.1 million ton in the year ended December 31, 2007, no tons in the year ended December 31, 2006, insignificant in the year ended December 31, 2005, 0.1 million tons in the year ended December 31, 2004 and 1.0 million tons in the year ended December 31, 2003.

(E) Amounts include intersegment transactions. For entities that are not wholly owned but in which CONSOL Energy owns at least 50% equity interest, includes a percentage of their net production, sales or reserves equal to CONSOL Energy s percentage equity ownership. For coal, amounts include 100% of our fully consolidated, 49% owned variable interest entity. Also for coal, Glennies Creek Mine is reported as an equity affiliate through February 2004. Glennies Creek Mine is reported as an equity affiliate for the entire 2003 period. Our proportionate share of the recoverable coal reserves for Glennies Creek Mine is 9.6 million tons at December 31, 2003. Line Creek was reported as an equity affiliate through February 2003. For gas, amounts include 100% of CNX Gas basis; they exclude the 18.3% minority interest reduction. Also for gas, Knox Energy makes up the equity earnings data in 2007, 2006, 2005, 2004 and 2003. Our proportionate share of proved reserves for gas equity affiliates is 3.6.x bcf, 2.2 bcf, 2.7 bcf, 2.4 bcf and 0.8 bcf at December 31, 2007, 2006, 2005, 2004 and 2003, respectively. Sales of gas produced by equity affiliates were 0.32 bcf in the year ended December 31, 2007; 0.22 bcf in the year ended December 31, 2006; 0.23 bcf in the year ended December 31, 2005; 0.20 bcf in the year ended December 31, 2004 and 0.08 bcf in the year ended December 31, 2003.

(F) Represents proven and probable coal reserves at period end.

(G) Represents average net sales price before the effect of derivative transactions.

(H) Represents proved developed and undeveloped gas reserves at period end.

Table of Contents

(I) EBIT is defined as earnings before deducting net interest expense (interest expense less interest income) and income taxes. EBITDA is defined as earnings before deducting net interest expense (interest expense less interest income), income taxes and depreciation, depletion and amortization. For 2004 and 2003 we have excluded the impacts of cumulative effects of accounting changes in the computation of EBIT and EBITDA. Although EBIT and EBITDA are not measures of performance calculated in accordance with generally accepted accounting principles, management believes that they are useful to an investor in evaluating CONSOL Energy because they are widely used in the coal industry as measures to evaluate a company s operating performance before debt expense and cash flow. Financial covenants in our credit facility include ratios based on EBITDA. EBIT and EBITDA do not purport to represent cash generated by operating activities and should not be considered in isolation or as a substitute for measures of performance in accordance with generally accepted accounting principles. In addition, because EBIT and EBITDA are not calculated identically by all companies, the presentation here may not be comparable to other similarly titled measures of other companies. Management s discretionary use of funds depicted by EBIT and EBITDA may be limited by working capital, debt service and capital expenditure requirements, and by restrictions related to legal requirements, commitments and uncertainties. A reconcilement of EBIT and EBITDA to financial net income is as follows:

(Unaudited))	**Year Ended December 31,**				
(In thousands)	**2007**	**2006**	**2005**	**2004**	**2003**
Net Income (Loss)	$ 267,782	$ 408,882	$ 580,861	$ 198,582	$ (7,798)
Add: Interest expense	30,851	25,066	27,317	31,429	34,451
Less: Interest income	(12,792)	(15,369)	(8,066)	(5,376)	(5,602)
Less: Interest income included in export sales excise tax resolution					(696)
Less: Cumulative Effect of Changes in Accounting for Workers Compensation Liability, net of Income Taxes of $53,080				(83,373)	
Less: Cumulative Effect of Changes in Accounting for Mine Closing, Reclamation and Gas Well Closing Costs, net of Income taxes of $3,035					