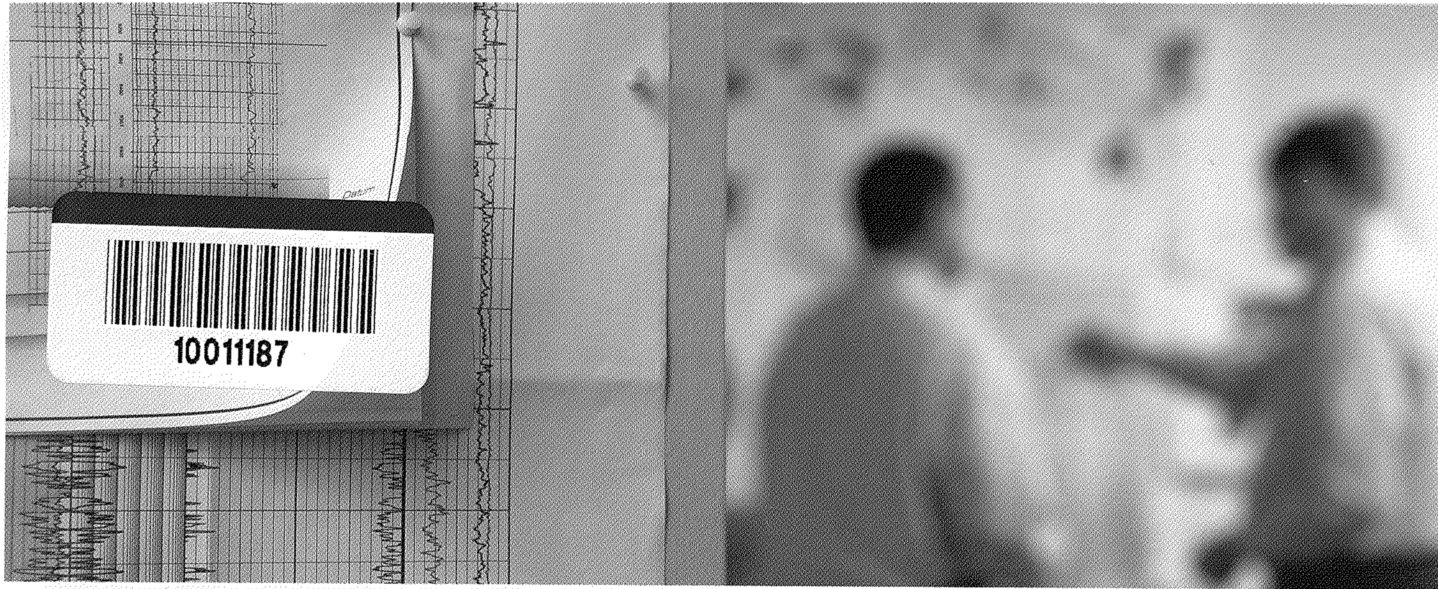
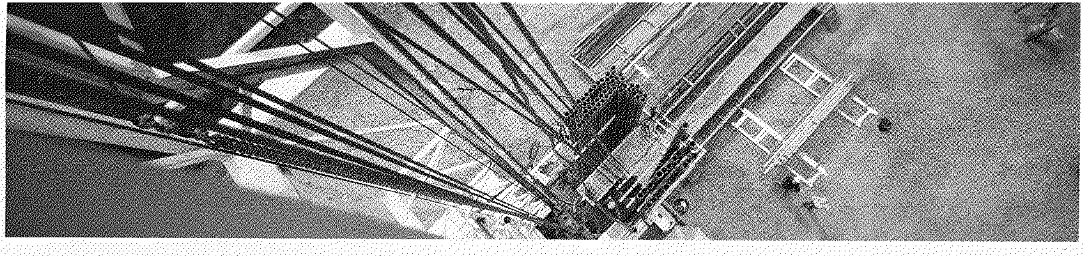
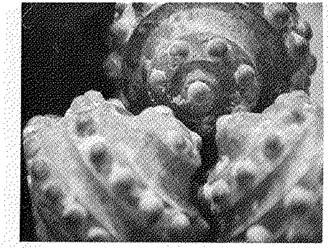


PENN VIRGINIA CORPORATION

2009 ANNUAL REPORT

Positioned for growth

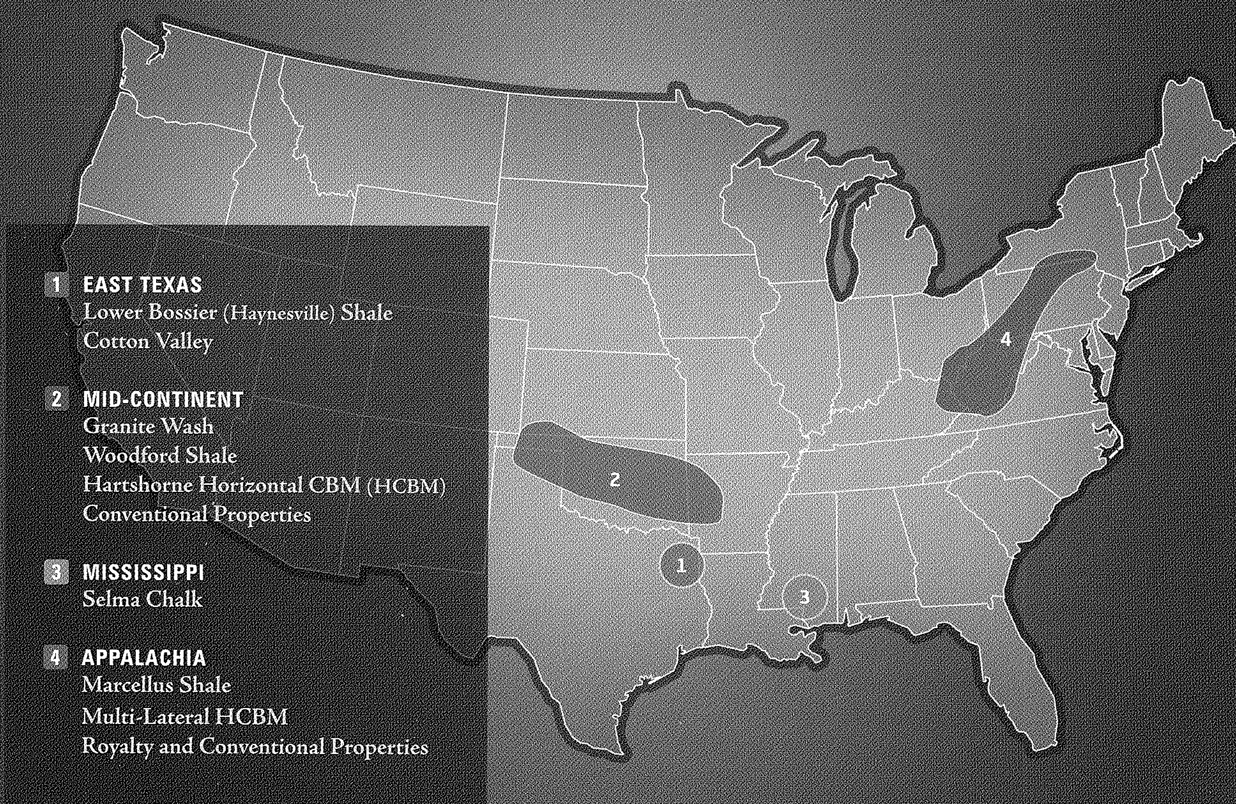




Headquartered in Radnor, PA and a member of the S&P SmallCap 600 Index, **Penn Virginia Corporation (NYSE: PVA)** is an independent natural gas and oil company focused on the development, exploration and production of reserves in domestic onshore regions.

PVA also owns approximately 51 percent of Penn Virginia GP Holdings, L.P. (NYSE: PVG), the owner of the general partner and the largest unitholder of Penn Virginia Resource Partners, L.P. (NYSE: PVR), a manager of coal and natural resource properties and related assets and the operator of a midstream natural gas gathering and processing business. For more information about PVA, please visit our website at www.pennvirginia.com.

CORE OIL & GAS PRODUCING AREAS



Financial Overview

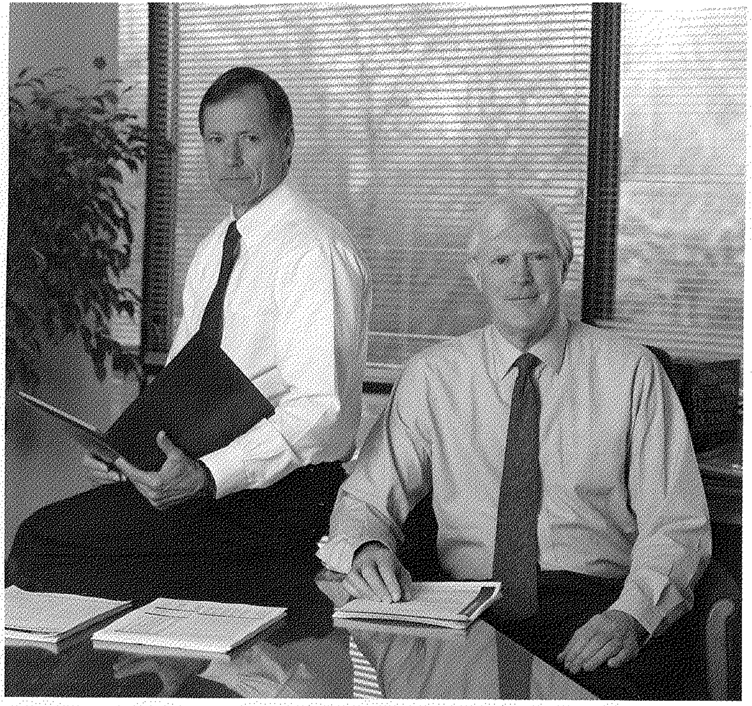
(in millions except per share data)

	2009	2008	2007	2006	2005
FINANCIAL DATA					
Net revenues[1]	$ 481.3	$ 736.2	$ 509.7	$ 419.3	$ 370.0
Operating income (loss)	(98.2)	256.8	192.6	170.5	162.0
Net income attributable to PVA	(114.6)	121.1	50.5	75.9	62.1
Net cash flows provided by operating activities	275.9	383.8	313.0	275.8	231.4
COMMON SHARE DATA[2]					
Net income, basic ($/share)	$ (2.62)	$ 2.89	$ 1.32	$ 2.03	$ 1.67
Net income, diluted ($/share)	(2.62)	2.87	1.31	2.01	1.66
Dividends paid ($/share)	0.23	0.23	0.23	0.23	0.23
Average shares outstanding, diluted	43.8	42.0	38.4	37.7	37.5
CAPITALIZATION					
Long-term debt, excluding current portion	$ 1,118.5	$ 1,100.0	$ 714.8	$ 428.2	$ 325.8
Total shareholders equity	1,238.0	1,222.4	911.7	815.8	618.9
Total capitalization	2,356.5	2,322.4	1,626.5	1,244.0	944.7
Long-term debt as percent of total capitalization	47%	47%	44%	34%	34%
PRODUCTION DATA					
Total oil and gas production (Bcfe)	51.0	46.9	40.6	31.3	27.4
Oil, condensate and natural gas liquids (Mbbls)	1,277	898	461	382	302
Natural gas (Bcf)	43.3	41.5	37.8	29.0	25.6
Daily production (MMcfe)	139.7	128.1	111.1	85.6	75.0
Coal produced by lessees (millions of tons)	34.3	33.7	32.5	32.8	30.2
System throughput volumes (MMcfd)	332	270	186	170	144
ESTIMATED RESERVES					
Total proved oil and gas reserves (Bcfe)	935	916	680	487	377
Coal (millions of recoverable tons)	829	827	818	765	689
REALIZED PRICES AND MARGINS					
Oil, condensate and natural gas liquids ($/Bbl)	$ 46.20	$ 75.52	$ 60.99	$ 55.59	$ 45.67
Natural gas ($/Mcf)	3.91	8.89	6.94	7.35	8.31
Coal royalties ($/ton)	3.51	3.65	2.89	2.99	2.74
Midstream processing margin ($/Mcf)	0.81	1.09	1.33	1.10	1.02

(1) 2009-2005 amounts are shown net of cost of midstream gas purchased of $407 million, $613 million, $343 million, $335 million and $304 million, respectively.
(2) Amounts per common share have been adjusted for the effect of two-for-one stock splits in June 2004 and June 2007.

HIGHLIGHTS

- Raised over $500 million of capital via debt and equity offerings, as well as the sale of non-core PVG units and exploration and production (E&P) assets
- Record year-end proved oil and gas reserves of 935 Bcfe, an increase of two percent over 916 Bcfe at year-end 2008
- Record oil and gas production of 51.0 Bcfe, an increase of nine percent over 46.9 Bcfe in 2008
- Pro forma to exclude production from Gulf Coast assets divested in January 2010, oil and gas production was 45.2 Bcfe, an increase of 13 percent over 39.9 Bcfe in 2008
- Reserve replacement ratio, excluding price revisions, of 270 percent at a cost of $1.25 per Mcfe added
- Oil and gas capital expenditures of approximately $172 million, including approximately $143 million for drilling and completion activities to drill 32 (20.7 net) wells, with a 96 percent success rate
- Record financial and operating results from the coal and natural resource and midstream businesses
- Distributions received from PVG and PVR in 2009 of $42.3 million



Dear Fellow Shareholders,

As 2009 began, we faced several challenges that we successfully overcame during the past twelve months. Thus, we enter 2010 having a more focused strategy and the financial wherewithal to take advantage of a number of exciting opportunities. Dramatic declines in commodity prices during the latter half of 2008 and 2009, coupled with the well-documented problems faced by lending institutions, resulted in liquidity issues for many companies in and out of the energy industry.

We were not immune from these problems and responded by curtailing capital expenditures and raising over $500 million of debt and equity capital, as well as selling non-core PVG units and E&P assets. As a result, we had an undrawn revolver of $300 million and cash on hand of approximately $100 million in early 2010.

Despite the cutbacks, our oil and gas business achieved record levels of production and proved reserves. We made progress in multiple areas, led by contributions from the East Texas, Mid-Continent and Mississippi regions. We set new company records and had strong results in a number of categories, including:

- Oil and natural gas production increased nine percent to a record 51.0 Bcfe
- Proved oil and gas reserves were up two percent to a record 935 Bcfe
- Reserve replacement was 146 percent at a cost of $2.30 per Mcfe added (270 percent at a cost of $1.25 per Mcfe added, excluding price revisions)

Due to low natural gas prices and $128 million in charges for impairments and drilling rig standby costs, we reported an operating loss of $98.2 million in 2009, as compared to operating income of $256.8 million in 2008. Cash flow from operating activities decreased 28 percent in 2009 to $275.9 million from $383.8 million in 2008, primarily due to low natural gas prices and the drilling rig standby charges.

Economic conditions and low prices for natural gas caused us to suspend operated drilling in the second and third quarters of 2009. In the fourth quarter of the year, we resumed a modest drilling program in the Lower Bossier (Haynesville) Shale in East Texas and also resumed operated drilling in the liquids-rich Granite Wash play in Oklahoma. As a result, during 2009 E&P capital expenditures, excluding leasehold acquisition, were

$153 million, a decrease of 72 percent as compared to the approximate $546 million spent in 2008. Nevertheless, these capital expenditures funded our growth to record production and proved reserve levels. Approximately $19 million of leasehold acquisitions were completed during the year, further adding to future development and exploration drilling locations and we expect to continue that trend in 2010.

Our oil and gas strategy during the past few years has been to develop a presence in several basins with the intention of ultimately selecting the areas where we wanted to focus our efforts. These choices have been made during the past twelve months. For the next several years, we plan to concentrate our exploration and development efforts in the Granite Wash, the Marcellus Shale in Pennsylvania and in multiple-pay zones in East Texas, including the Lower Bossier (Haynesville) Shale. In addition, we expect to continue development drilling in the Mississippi Selma Chalk, where we are one of the dominant operators.

During 2009 we made the decision to monetize our south Louisiana and south Texas assets (the sale closed in January 2010), as well as our modest positions in the Bakken and Fayetteville Shale plays. We suspended our horizontal coalbed methane (HCBM) activities in West Virginia and Oklahoma. These plays are viable, especially at higher natural gas prices; however, they are not a current priority.

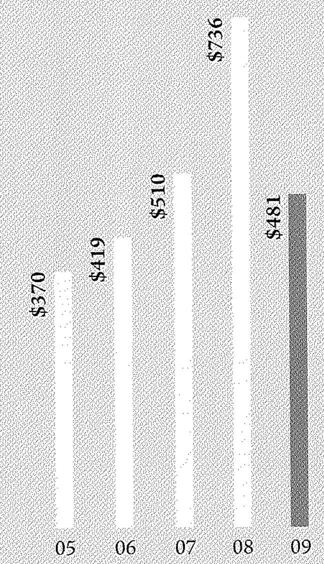
We own 51 percent of, and are the general partner of, Penn Virginia GP Holdings, L.P. (NYSE:PVG), which in turn is the owner of the general partner and largest unitholder of Penn Virginia Resource Partners, L.P. (NYSE: PVR), a manager of coal and natural resource properties and related assets and the operator of a midstream natural gas gathering and processing business. During the third quarter of 2009, we sold approximately one-third of our holdings in PVG in a public offering, reducing ownership from 77 percent to 51 percent. Our ownership in PVG, while a non-core asset to our E&P business, benefited in 2009 from record lessee coal production and natural gas system throughput volumes which provided record distributable cash flow as an underpinning for our $31 million annualized distribution cash flow stream from PVG.

The current economy is uncertain at best and there is an apparent oversupply of natural gas that acts as a damper on prices. However, we came through 2009 with a strong balance sheet, a focused strategy and a portfolio of high-quality drilling prospects. We believe we are well-positioned to take on the challenges of 2010 and beyond, with the goal of providing increased value to you, our shareholders. As always, we greatly appreciate the hard work and dedication of our employees and the continued loyalty and support of our shareholders.

ROBERT GARRETT
Chairman

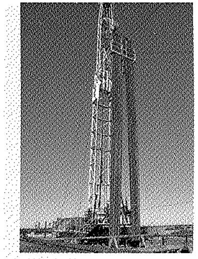
A. JAMES DEARLOVE
President and Chief Executive Officer

NET REVENUES
(dollars in millions)



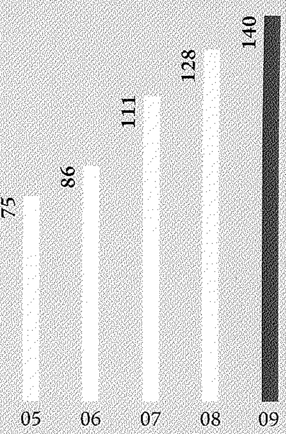
CASH FLOW FROM OPERATIONS
(dollars in millions)

Oil & Gas Production



During 2009, we enjoyed continued reserve and production growth primarily from our Granite Wash and Lower Bossier (Haynesville) Shale plays, as well as contributions from the Selma Chalk in Mississippi.

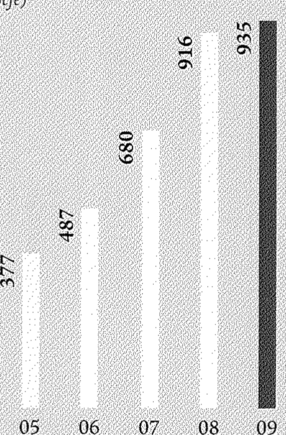
OIL & GAS PRODUCTION
(MMcfe/d)



2009 PRODUCTION

	(Bcfe)	%Total
East Texas	13.1	26%
Mid-Continent	12.8	25%
Mississippi	7.8	15%
Appalachia	11.5	23%
Gulf Coast	5.7	11%
Totals	51.0	100%

PROVED OIL/GAS RESERVES
(Bcfe)



PROVED OIL/GAS RESERVES

	(Bcfe)	%Total
East Texas	403.3	43%
Mid-Continent	198.7	21%
Mississippi	174.9	19%
Appalachia	134.0	14%
Gulf Coast	24.1	3%
Totals	935.0	100%

Our strategy is to continue to focus on relatively low-risk unconventional and resource plays in our core areas. These core areas and plays include the Granite Wash and Woodford Shale in the Mid-Continent region, the Lower Bossier (Haynesville) Shale and Cotton Valley in East Texas, the Selma Chalk in Mississippi and the Marcellus Shale in Pennsylvania. Our current 2010 plans include development drilling in the Granite Wash and Selma Chalk plays, and testing of the Lower Bossier Shale, Cotton Valley, Marcellus Shale, new Granite Wash acreage and the Woodford Shale plays.

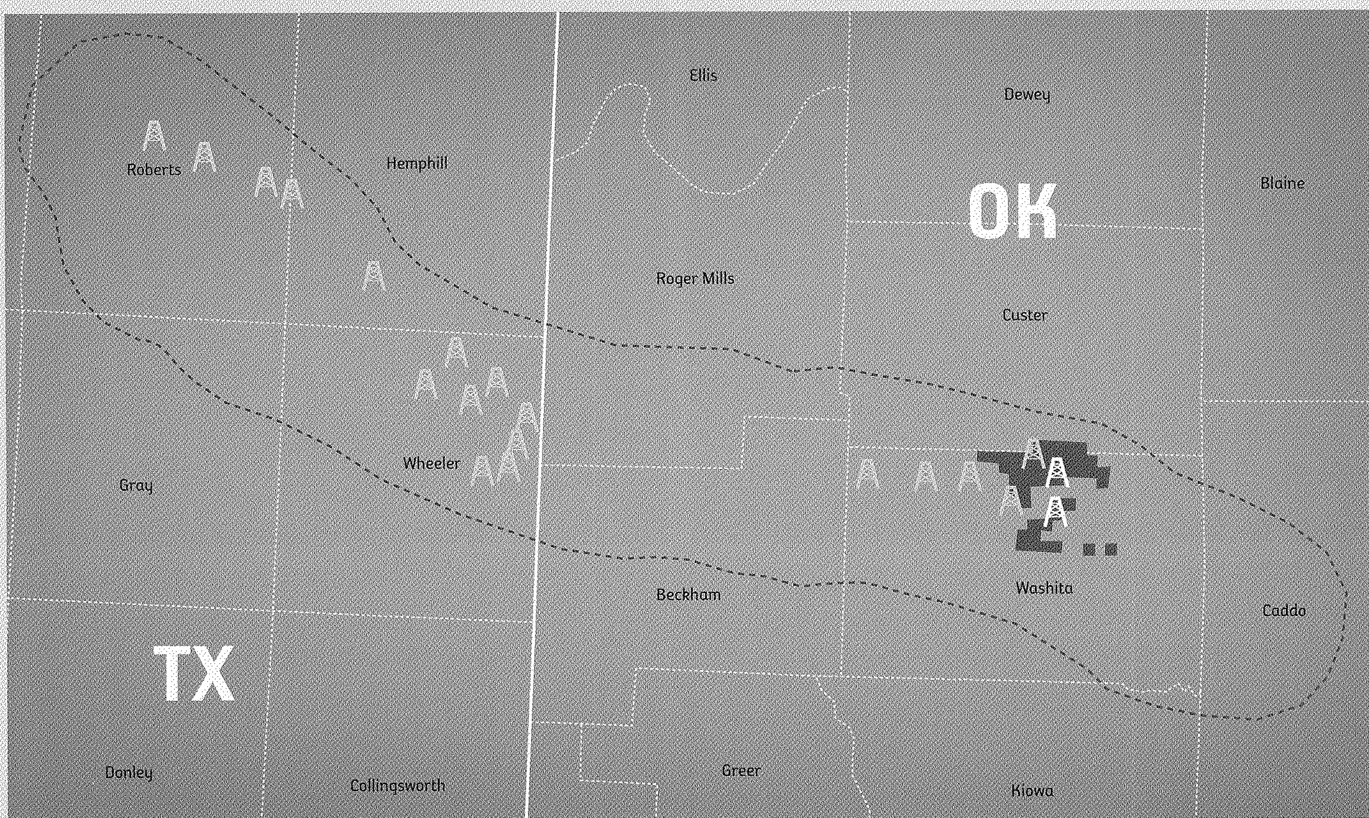
Despite low gas prices, lower cash flows and reduced capital expenditures in 2009, our successful drilling activity led to record levels of proved reserves and production:

- We drilled 32 (20.7 net) wells during 2009, including 30 (19.7 net) development wells and two (1.0 net) exploratory wells. Only one well was unsuccessful, with four development wells waiting on completion or under evaluation at year-end, for a 96 percent overall success rate.
- Oil and gas production in 2009 was 51.0 Bcfe (45.2 Bcfe, pro forma to exclude divested Gulf Coast assets), a new record which eclipsed the 46.9 Bcfe in 2008 by nine percent (pro forma production increased by 13 percent).
- Our estimated proved reserves at the end of 2009 were a record 935 Bcfe, up two percent from 916 Bcfe at the end of 2008. Natural gas comprised approximately 83 percent of year-end proved reserves and 47 percent of reserves were proved developed. Net of revisions, we added approximately 70 Bcfe of proved reserves, replacing approximately 146 percent of 2009 production at a reserve replacement cost of $2.30 per Mcfe (excluding price revisions, we replaced 270 percent at a cost of $1.25 per Mcfe).

Granite Wash

(Horizontal Wells, Washita County, Oklahoma)

PVA ACTIVITY | INDUSTRY ACTIVITY | PVA ACREAGE

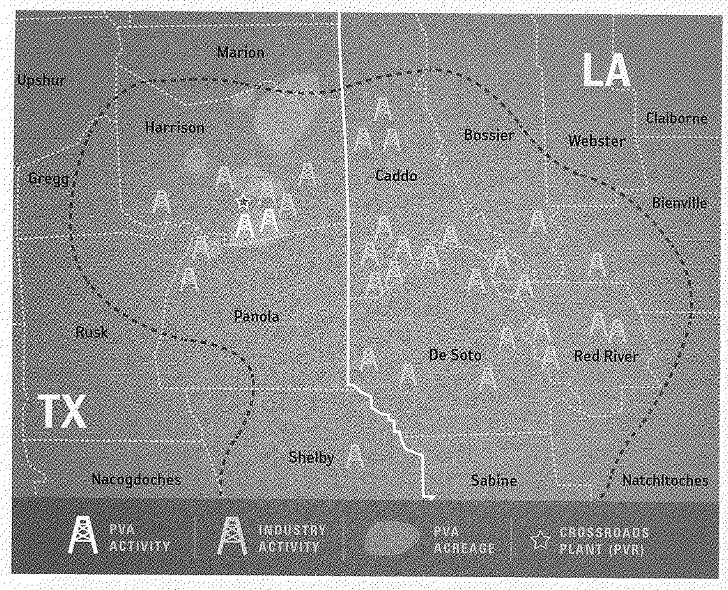


In late 2007, a horizontal Granite Wash play began to emerge in the Anadarko Basin of western Oklahoma that has become one of the highest rate-of-return plays in the country.

Our presence in the play is the result of an acquisition we made in 2006. Through the end of 2009, we, along with our joint venture partner, Chesapeake Energy Corp. (NYSE: CHK), have drilled approximately 30 horizontal wells in the play. The typical well costs approximately $6 million and is expected to provide an average estimated ultimate recovery (EUR) of approximately 6 Bcfe, with about one-third of the reserves in the form of oil and condensate, with the balance in BTU-rich natural gas. The typical rate of return for our Granite Wash wells is over 100 percent assuming recent commodity price levels, due to the liquids content of the production stream and the relatively low-cost wells.

We entered 2009 with approximately 10,000 net acres in the joint venture with CHK, but have more than doubled our position to approximately 25,000 net acres and have expanded its position beyond the original footprint (in the map above) to multiple prospect areas which will be tested in 2010. We currently have approximately 170 horizontal locations to drill on our established acreage – with 38 wells planned to be drilled in 2010 – and could add significantly to that inventory if the testing of the new prospects succeeds.

Lower Bossier (Haynesville) Shale, Cotton Valley Sands *(Horizontal Wells, East Texas)*

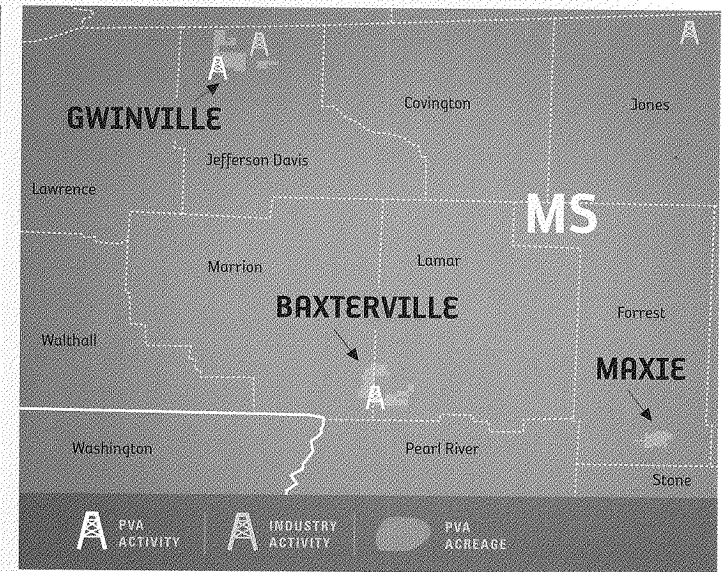


Our largest reserve base and an area that we expect to have significant production growth potential over the next few years is East Texas.

One of the most promising and potentially most prolific natural gas shale plays in the U.S. is the Lower Bossier (Haynesville) Shale in east Texas and northwest Louisiana. In addition, the Cotton Valley sands, to which we have drilled approximately 320 vertical wells over the past few years, will be tested on a horizontal basis during 2010.

We have approximately 45,000 net acres in East Texas which is prospective for the Lower Bossier Shale and the horizontal Cotton Valley. Through February 2010, we have drilled 20 horizontal wells in this play and are continuing to test this play with up to seven test wells planned for 2010. In the Cotton Valley we plan to drill up to eight test wells in 2010. Dependent upon commodity prices, we will move to a development program for both plays that should provide "double-barreled" growth over the next several years.

Selma Chalk *(Horizontal Wells, Mississippi)*

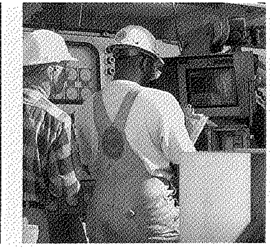


In 1999, we acquired our initial position in the vertical Selma Chalk play in Mississippi and have drilled over 400 wells since then.

This historically vertical play became more economic when drilling and completions took on a horizontal orientation in 2007. Through February 2010, we have drilled 22 horizontal wells and expect to drill up to 18 horizontal wells in 2010.

We have approximately 30,000 net acres in south central Mississippi, which is prospective for the horizontal Selma Chalk in three fields (Baxterville, Gwinville and Maxie). As part of our January 2010 divestiture of Gulf Coast assets, we purchased some additional acreage in the Gwinville Field and added both production and drilling locations to our inventory. We are a leading producer in this play and one of the most active drillers in this play, which has attractive well economics. Dependent upon commodity prices, as well as the number of rigs which we choose to operate in this play, we expect significant growth from this play over the next several years.

Emerging Plays



Marcellus Shale

Potentially one of the most economic and prolific natural gas shale plays in the U.S. is northern Appalachia's Marcellus Shale play.

Ranging from northern West Virginia through Pennsylvania into the Southern Tier of New York, the Marcellus Shale play is thought to have resource potential equal in size to a combination of the other leading shale plays (e.g., Barnett, Lower Bossier/ Haynesville and Fayetteville Shales) due to its vast areal extent, as well as very good well economics for producers in an area that is close to consuming markets.

- We have over 30,000 net acres primarily in north central and southwestern Pennsylvania that is believed to have potential for the Marcellus Shale
- We commenced exploration in the play during early 2010
- We plan to drill up to six horizontal and vertical test wells during 2010 in both north central and southwestern Pennsylvania
- We expect to spend up to approximately $50 million in leasehold acquisition during 2010, or approximately 12 percent of our overall capital budget
- As discussed further below, we will open a regional office in Pittsburgh in April 2010, joining a number of other Marcellus players who have established regional headquarters there to help expand their presence in the play

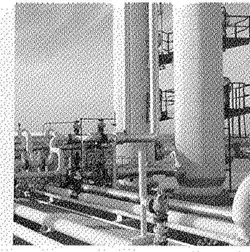
Woodford Shale

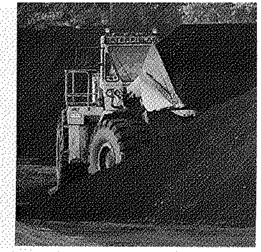
Another play for us in the Mid-Continent region is the Woodford Shale in the Arkoma and Anadarko Basins.

In 2006, we acquired our initial position in the Mid-Continent, primarily to drill horizontal coalbed methane wells. Over time, another play that has emerged with the potential to be an important producing area for us is the Woodford Shale. The play is one of the top shale plays in the country, but the pace of development has been hampered by weak gas prices.

- We have approximately 25,000 net acres to develop in the play in the Arkoma Basin and nearly 45,000 net acres in the Anadarko Basin to explore
- We have participated in a number of these wells in the Arkoma Basin with reserves of at least 3 Bcfe based on early results
- We plan to drill an exploratory horizontal well in the Anadarko Basin during 2010 that will test the Woodford Shale
- A recovery in natural gas prices could warrant further development in this play

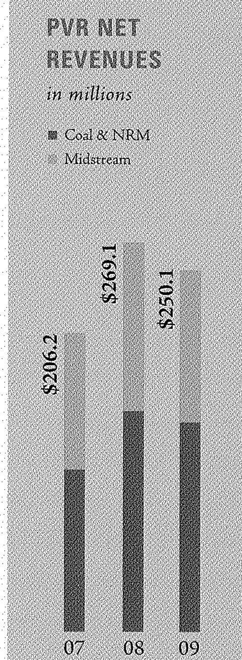
PVR *(Coal and Natural Resource Management; Natural Gas Midstream)*

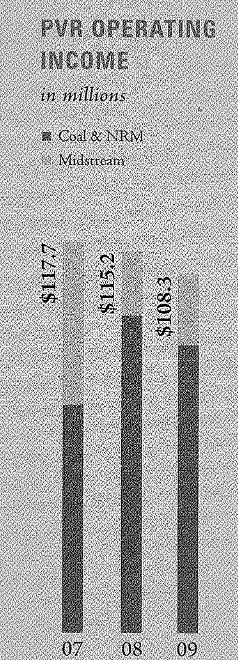




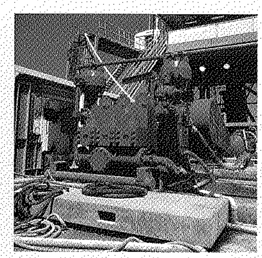
Through PVR's Coal and Natural Resource Management segment, we owned or controlled approximately 829 million tons of proven and probable coal reserves as of December 31, 2009, primarily in Central Appalachia and the Illinois Basin. PVR's lessees produced 34.3 million tons in 2009, up two percent from 33.7 million tons in 2008. PVR Midstream had system throughput volumes of 332 MMcf per day in 2009, up 23 percent from 270 MMcf per day in 2008.

In 2009, PVR completed the expansion and acquisition of 100 MMcf per day of natural gas midstream processing capacity in the Panhandle System, increasing overall processing capacity by one-third to 400 MMcf per day. In March 2010, we announced an expansion of PVR Midstream into the Marcellus Shale in Pennsylvania to provide gathering systems and compression that are expected to provide significant growth for PVR Midstream in coming years. As is the case with our E&P segment, we believe that we are well-positioned for diversified operating and cash flow growth at PVR over the next few years.





PVA Office Opening in Pittsburgh



In April 2010, we will open a regional office for Penn Virginia Oil & Gas Corporation, our oil and gas subsidiary, in Pittsburgh, PA.

This office will replace our former eastern region headquarters in Kingsport, TN, and will move us to the hub of the Pennsylvania-based Marcellus Shale play. Over the next several years, we anticipate growth in our eastern operations, given the potential presented by the Marcellus Shale. The Marcellus Shale is a play that is expected to be both prolific in size – equal in potential resource size to other plays on a combined basis – as well as highly economic given its relatively low-cost drilling and per well production and reserve potential. We believe that establishing a presence in Pittsburgh positions us among the emerging community of oil and gas firms in the region as we compete to develop and expand our resource base and our team.

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

SEC Mail Processing
Section

APR 06 2010

Washington, DC
110

FORM 10-K

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

For the fiscal year ended December 31, 2009

Commission file number: 1-13283

Penn Virginia Corporation

(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Radnor Corporate Center, Suite 300
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

Registrant's telephone number, including area code: (610) 687-8900

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

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

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	New York Stock Exchange

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 ("Exchange Act"). Yes ☐ No ☒

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

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

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

Large accelerated filer ☒ 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 Exchange Act). Yes ☐ No ☒

The aggregate market value of common stock held by non-affiliates of the registrant was $532,899,076 as of June 30, 2009 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant, but excluding any institutional shareholders. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 22, 2010, 45,409,837 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 5, 2010, is incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

Table of Contents

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or Exchange Act. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- the volatility of commodity prices for natural gas, NGLs, crude oil and coal;
- our ability to access external sources of capital;
- uncertainties relating to the occurrence and success of capital-raising transactions, including securities offerings and asset sales;
- reductions in the borrowing base under our revolving credit facility, or Revolver;
- our ability to develop and replace oil and gas reserves and the price for which such reserves can be acquired;
- any impairment write-downs of our reserves or assets;
- reductions in our anticipated capital expenditures;
- the relationship between natural gas, NGL, crude oil and coal prices;
- the projected demand for and supply of natural gas, NGLs, crude oil and coal;
- the availability and costs of required drilling rigs, production equipment and materials;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production;
- competition among producers in the oil and natural gas and coal industries generally and among natural gas midstream companies;
- the extent to which the amount and quality of actual production of our oil and natural gas or Penn Virginia Resource Partners, L.P., or PVR's, coal differ from estimated proved oil and gas reserves and recoverable coal reserves;
- PVR's ability to generate sufficient cash from its businesses to maintain and pay the quarterly distribution to its general partner and its unitholders;
- the experience and financial condition of PVR's coal lessees and natural gas midstream customers, including the lessees' ability to satisfy their royalty, environmental, reclamation and other obligations to PVR and others;
- operating risks, including unanticipated geological problems, incidental to our business and to PVR's coal and natural resource management or natural gas midstream business;
- PVR's ability to acquire new coal reserves or natural gas midstream assets and new sources of natural gas supply and connections to third-party pipelines on satisfactory terms;
- PVR's ability to retain existing or acquire new natural gas midstream customers and coal lessees;
- the ability of PVR's lessees to produce sufficient quantities of coal on an economic basis from PVR's reserves and obtain favorable contracts for such production;
- the occurrence of unusual weather or operating conditions including force majeure events;
- delays in anticipated start-up dates of our oil and natural gas production, of PVR's lessees' mining operations and related coal infrastructure projects and new processing plants in PVR's natural gas midstream business;
- environmental risks affecting the drilling and producing of oil and gas wells, the mining of coal reserves or the production, gathering and processing of natural gas;

- the timing of receipt of necessary governmental permits by us and by PVR or PVR's lessees;
- hedging results;
- accidents;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including with respect to emissions levels applicable to coal-burning power generators;
- uncertainties relating to the outcome of current and future litigation regarding mine permitting;
- risks and uncertainties relating to general domestic and international economic (including inflation, interest rates and financial and credit markets) and political conditions (including the impact of potential terrorist attacks);
- Penn Virginia GP Holdings, L.P.'s ability to generate sufficient cash from its interests in PVR to maintain and pay the quarterly distribution to its unitholders;
- uncertainties relating to our continued ownership of interests in PVG and PVR; and
- other risks set forth in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2009.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

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Part I

Item 1 Business

General

Penn Virginia Corporation (NYSE: PVA) is an independent oil and gas company primarily engaged in the development, exploration and production of natural gas and oil in various domestic onshore regions including East Texas, the Mid-Continent, Appalachia and Mississippi. We also indirectly own partner interests in Penn Virginia Resource Partners, L.P. (NYSE: PVR), or PVR, a publicly traded limited partnership formed by us in 2001. Our ownership interests in PVR are held principally through our general partner interest and our 51.4% limited partner interest in Penn Virginia GP Holdings, L.P. (NYSE: PVG), or PVG, a publicly traded limited partnership formed by us in 2006. As of December 31, 2009, PVG owned an approximate 37% limited partner interest in PVR and 100% of the general partner of PVR, which holds a 2% general partner interest in PVR and all of the incentive distribution rights, or IDRs. During 2009, we sold a portion of our limited partner interest in PVG in a public offering, reducing our limited partner interest in PVG from 77% to 51.4%. See "— Corporate Structure."

PVG consolidates PVR's results into its financial statements because PVG controls PVR's general partner. We consolidate PVG's results into our financial statements because we control PVG's general partner. PVG and PVR function with capital structures that are independent of each other and us. While we report consolidated financial results of PVR's coal and natural resource management and natural gas midstream businesses, the only cash we received from those businesses is in the form of cash distributions we received from PVG and PVR in respect of our partner interests in each of them. We received cash distributions of $42.3 million, $44.0 million and $29.8 million in the years ended December 31, 2009, 2008 and 2007 as a result of our partner interests in PVG and PVR.

Unless the context requires otherwise, references to the "Company," "Penn Virginia," "we," "us" or "our" in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Segments

We are engaged in three primary business segments: (i) oil and gas, (ii) coal and natural resource management and (iii) natural gas midstream. We operate our oil and gas segment, and PVR operates the coal and natural resource management and natural gas midstream segments.

Oil and Gas Segment Overview

We have a geographically diverse asset base with core areas of operation in the East Texas, Mid-Continent, Appalachian and Mississippi regions of the United States. As of December 31, 2009, we had proved natural gas and oil reserves of approximately 935 Bcfe, of which 83% were natural gas and 47% were proved developed. Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects.

As of December 31, 2009, 97% of our proved reserves were located in primarily longer-lived, lower-risk basins in East Texas, the Mid-Continent, Appalachia and Mississippi, which comprised 43%, 21%, 14% and 19%, respectively, of the proved reserves. We sold our Gulf Coast properties, representing 3% of proved reserves, in a transaction that closed on January 29, 2010. In 2009, we produced 51.0 Bcfe, a 9% increase compared to 46.9 Bcfe in 2008, with East Texas, the Mid-Continent, Appalachia, Mississippi and the Gulf Coast comprising 26%, 25%, 23%, 15% and 11% of total production volumes. In the three years ended December 31, 2009, we drilled 607 gross (413.3 net) wells, of which 93% were successful in producing natural gas in commercial quantities. For a more detailed discussion of our reserves and production, see Item 2, "Properties."

The primary development play types that our oil and gas operations are focused on include: (i) the horizontal Lower Bossier (Haynesville) Shale and Cotton Valley plays in East Texas, (ii) the horizontal Granite Wash play in the Mid-Continent and (iii) the predominantly horizontal Selma Chalk play in Mississippi. In addition, we intend to focus on drilling exploratory wells in the Marcellus Shale play in Appalachia in order to determine whether our leasehold acreage position there will support a development program.

We have grown our reserves and production primarily through development and exploratory drilling, complemented to a lesser extent by making strategic acquisitions. Despite a challenging year in 2009, we replaced approximately 147% of our 2009 production entirely through the drillbit by adding approximately 75 Bcfe of proved reserves from extensions, discoveries and additions, net of revisions. In 2009, capital expenditures in our oil and gas segment were $171.8 million, of which $140.2 million, or 82%, was related to development drilling and $18.7 million, or 11%, was related to leasehold acquisitions. The remaining $12.9 million, or 7%, was related to exploration drilling, pipelines, gathering and facilities.

As of December 31, 2009, we owned 1.1 million net acres of leasehold interests, approximately 34% of which were undeveloped. Many of our proved undeveloped locations and additional potential drilling locations are direct offsets or extensions from existing production. We believe our existing undeveloped acreage position represents over 10 years of drilling opportunities based on our historical drilling rate.

PVR Coal and Natural Resource Management Segment Overview

The PVR coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. PVR also earns revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.

As of December 31, 2009, PVR owned or controlled approximately 829 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. PVR enters into long-term leases with experienced, third-party mine operators, providing them the right to mine PVR's coal reserves in exchange for royalty payments. PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from PVR's properties. PVR does not operate any mines. In 2009, PVR's lessees produced 34.3 million tons of coal from its properties and paid PVR coal royalties revenues of $120.4 million, for an average royalty per ton of $3.51. Approximately 82% of PVR's coal royalties revenues in 2009 were derived from coal mined on PVR's properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price. The balance of PVR's coal royalties revenues for the respective periods was derived from coal mined on PVR's properties under leases containing fixed royalty rates that escalate annually. See "— Contracts — PVR Coal and Natural Resource Management Segment" for a description of PVR's coal leases.

PVR Natural Gas Midstream Segment Overview

PVR's natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. As of December 31, 2009, PVR owned and operated natural gas midstream assets located in Oklahoma and Texas, including six natural gas processing facilities having 400 MMcfd of total capacity and approximately 4,118 miles of natural gas gathering pipelines. PVR's natural gas midstream business earns revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, PVR owns a 25% member interest in Thunder Creek Gas Services, LLC, or Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

In 2009, system throughput volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 121.3 Bcf, or approximately 332 MMcfd.

Business Strategy

We intend to pursue the following business strategies:

- *Grow primarily through development drilling.* We anticipate spending up to $425 million on oil and gas capital expenditures in 2010. We plan to allocate up to $275 million, or approximately 65%, of this amount to development drilling and related projects in our core areas of East Texas, the Mid-Continent and Mississippi. We are applying horizontal drilling technology in each of the core areas which may result in increased reserve additions, higher production rates and increased rates of return.

- Use *exploratory drilling to provide operational balance and future development growth opportunities.* We anticipate allocating up to $45 million, or approximately 11%, of our 2010 oil and gas capital expenditures to our exploratory drilling activities, including new prospects in the Granite Wash play in the Mid-Continent and the Marcellus Shale play in Pennsylvania. Both regions have prolific reserve and production growth potential.
- *Pursue selective leasehold and producing property acquisition opportunities in existing basins.* Historically, the majority of our growth in proved reserves and production has been achieved by drilling wells, or "through the drillbit." Our experienced team of management and technical professionals looks for opportunities to extend our leasehold acreage holdings, especially in our core areas and in the Marcellus Shale play in Pennsylvania. We anticipate allocating up to $85 million, or approximately 20%, of our 2010 oil and gas capital expenditures to leasehold acquisitions. While we do not presently anticipate producing property acquisitions in our 2010 oil and gas capital expenditures, we may consider making these types of acquisitions in our core and target areas as opportunities arise.
- *Manage risk exposure through an active hedging program.* We actively manage our exposure to commodity price fluctuations by hedging the commodity price risk for our expected production through the use of derivatives, typically costless collar contracts. The level of our hedging activity and duration of the instruments employed depend upon our cash flow at risk, available hedge prices and our operating strategy. For 2010, we have hedged approximately 55% of our estimated natural gas production, at average floor and ceiling prices of $6.09 and $8.19 per MMBtu, respectively.
- *Manage cash liquidity and balance sheet debt levels.* In response to difficult conditions in the financial and commodity markets during 2009, we significantly reduced oil and gas capital spending levels from 2008, while taking steps to improve our balance sheet and cash liquidity by raising $65 million of new equity capital and completing a $300 million initial public debt offering. We also improved our cash liquidity position by selling non-core assets during 2009, including the sale of a portion of our holdings in PVG for net proceeds of $118.1 million, excluding transaction costs, as well as certain oil and gas assets. We expect to continue to use debt financing, supplemented with equity issuances and the sale of other non-core assets potentially including all or part of our interests in PVG, to fund our growth profile while maintaining a conservative capital structure.

Contracts

Oil and Gas Segment

Transportation. We have entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging from one to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Marketing. We generally sell our natural gas using spot market and short-term fixed price physical contracts. For the year ended December 31, 2009, approximately 13% and 12% of our oil and gas segment revenues and 4% and 3% of our total consolidated revenues resulted from two of our oil and gas customers, Dominion Field Services, Inc. and Chesapeake Operating, Inc.

PVR Coal and Natural Resource Management Segment

PVR earns most of its coal royalties revenues under long-term leases that generally require its lessees to make royalty payments to it based on the higher of a percentage of the gross sales price or a fixed price per ton of coal they sell. The balance of PVR's coal royalties revenues is earned under long-term leases that require the lessees to make royalty payments to PVR based on fixed royalty rates that escalate annually. A typical lease either expires upon exhaustion of the leased reserves or has a five to ten-year base term, with the lessee having an option to extend the lease for at least five years after the expiration of the base term. Substantially all of PVR's leases require the lessee to pay minimum rental payments to PVR in monthly or annual installments, even if no mining activities are ongoing. These minimum rentals are recoupable, usually over a period from one to three years from the time of payment, against the production royalties owed to PVR once coal production commences.

Substantially all of PVR's leases impose obligations on the lessees to diligently mine the leased coal using modern mining techniques, indemnify PVR for any damages it incurs in connection with the lessee's mining operations, including any damages PVR may incur due to the lessee's failure to fulfill reclamation or other environmental obligations, conduct mining operations in compliance with all applicable laws, obtain its written consent prior to assigning the lease and maintain commercially reasonable amounts of general liability and other insurance. Substantially all of the leases grant PVR the right to review all lessee mining plans and maps, enter the leased premises to examine mine workings and conduct audits of lessees' compliance with lease terms. In the event of a default by a lessee, substantially all of the leases give PVR the right to terminate the lease and take possession of the leased premises.

In addition, PVR earns revenues under coal services contracts, timber contracts and oil and gas leases. PVR's coal services contracts generally provide that the users of PVR's coal services pay PVR a fixed fee per ton of coal processed at its facilities. All of PVR's coal services contracts are with lessees of PVR's coal reserves and these contracts generally have terms that run concurrently with the related coal lease. PVR's timber contracts generally provide that the timber companies pay PVR a fixed price per thousand board feet of timber harvested from PVR's property. PVR receives royalties under its oil and gas leases based on a percentage of the revenues the producers receive for the oil and gas they sell.

PVR Natural Gas Midstream Segment

PVR's natural gas midstream business generates revenues primarily from gas purchase and processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. During the year ended December 31, 2009, PVR's natural gas midstream business generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs: (i) gas purchase/keep-whole and (ii) percentage-of-proceeds. For the fourth quarter of 2009, approximately 28% of PVR's system throughput volumes were gathered or processed under gas purchase/keep-whole contracts, 53% were gathered or processed under percentage-of-proceeds contracts and 19% were gathered or processed under fee-based gathering contracts. A majority of the gas purchase/keep-whole and percentage-of-proceeds contracts include fee-based components such as gathering and compression charges.

In 2009, 21% of the PVR natural gas midstream segment's revenues and 13% of our total consolidated revenues resulted from one of PVR's natural gas midstream customers, Conoco, Inc.

Gas Purchase/Keep-Whole Arrangements. Under gas purchase/keep-whole arrangements, PVR generally purchases natural gas at the wellhead at either (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) a combination of (i) and (ii). PVR then gathers the natural gas to one of its plants where it is processed to extract the entrained NGLs, which are then sold to third parties at market prices. PVR resells the remaining natural gas to third parties at an index price which typically corresponds to the specified purchase index. Because the extraction of the NGLs from the natural gas during processing reduces the BTU content of the natural gas, PVR retains a reduced volume of gas to sell after processing. Accordingly, under these arrangements, PVR's revenues and gross margins increase as the price of NGLs increases relative to the price of natural gas, and its revenues and gross margins decrease as the price of natural gas increases relative to the price of NGLs. PVR has generally been able to mitigate its exposure in the latter case by requiring the payment under many of its gas purchase/keep-whole arrangements of minimum processing charges which ensure that PVR receives a minimum amount of processing revenues. The gross margins that PVR realizes under the arrangements described in clauses (i) and (iii) above also decrease in periods of low natural gas prices because these gross margins are based on a percentage of the index price.

Percentage-of-Proceeds Arrangements. Under percentage-of-proceeds arrangements, PVR generally gathers and processes natural gas on behalf of producers, sells the resulting residue gas and NGL volumes at market prices and remits to producers an agreed-upon percentage of the proceeds of those sales based on either an index price or the price actually received for the gas and NGLs. Under these types of arrangements, PVR's revenues and gross margins increase as natural gas prices and NGL prices increase, and its revenues and gross margins decrease as natural gas prices and NGL prices decrease.

Fee-Based Arrangements. Under fee-based arrangements, PVR receives fees for gathering, compressing and/or processing natural gas. The revenues PVR earns from these arrangements are directly dependent on the volume of natural gas that flows through its systems and are independent of commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, PVR's revenues from these arrangements would be reduced due to the related reduction in drilling and development of new supply.

In many cases, PVR provides services under contracts that contain a combination of more than one of the arrangements described above. The terms of PVR's contracts vary based on gas quality conditions, the competitive environment at the time the contracts were signed and customer requirements. The contract mix and, accordingly, exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

Natural Gas Marketing Contracts. PVR is also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems such as Enogex and Panhandle Eastern Pipeline and at market hubs accessed by various interstate pipelines. Connect Energy Services, LLC, or Connect Energy, PVR's wholly owned subsidiary, has earned fees from Penn Virginia Oil & Gas, L.P., or PVOG LP, our wholly owned subsidiary, since September 1, 2006, for marketing a portion of PVOG LP's natural gas production. For the years ended December 31, 2009 and 2008, PVR's natural gas marketing activities generated $1.8 million and $5.8 million in net revenues. Fees paid to the PVR natural gas midstream segment by our oil and gas segment are eliminated in consolidation.

Commodity Derivative Contracts

Oil and Gas Segment Commodity Derivatives. We utilize three-way collar derivative contracts to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

A three-way collar contract consists of a collar contract plus a put option contract sold by us with a price below the floor price of the collar. The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

The additional put option sold by us requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. If market prices are below the additional put option, we would be entitled to receive the market price plus the difference between the additional put option and the floor. See the oil and gas segment commodity derivative table in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk — Price Risk." This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

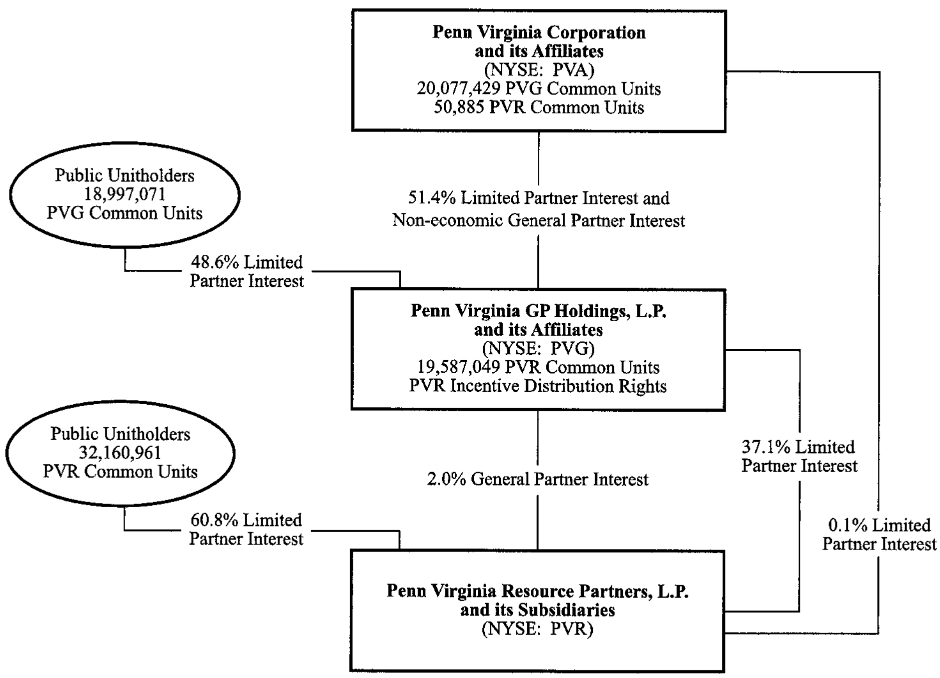
We determine the fair values of our oil and gas derivative agreements based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of December 31, 2009. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position and our own credit risk if the derivative is in a liability position.

PVR Natural Gas Midstream Segment Commodity Derivatives. PVR utilizes collar derivative contracts to hedge against the variability in its frac spread. PVR's frac spread is the spread between the purchase price for the natural gas PVR purchases from producers and the sale price for NGLs that PVR sells after processing. PVR hedges against the variability in its frac spread by entering into costless collar and swap derivative contracts to sell NGLs forward at a predetermined commodity price and to purchase an equivalent volume of natural gas forward on an MMBtu basis. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues or cost savings from favorable price movements.

See Note 8 to the Consolidated Financial Statements for a further description of our and PVR's derivatives programs.

Corporate Structure

We are a Virginia corporation formed in 1882. As of December 31, 2009, we owned the general partner of PVG and an approximately 51.4% limited partner interest in PVG. PVG owns an approximately 37% limited partner interest in PVR and the general partner of PVR, which holds a 2% general partner interest in PVR and all of the IDRs. We directly owned an additional 0.1% limited partner interest in PVR as of December 31, 2009. The following diagram depicts our ownership of PVG and PVR as of December 31, 2009:



Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's consolidated financial statements. Because we control the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. However, PVG and PVR function with capital structures that are independent of each other and us, with each having publicly traded common units and PVR having its own debt instruments. PVG does not currently have any debt instruments. While we report consolidated financial results of PVR's coal and natural resource management and natural gas midstream businesses, the only cash we receive from those businesses is in the form of cash distributions we receive from PVG and PVR in respect of our partner interests in each of them.

PVG and PVR Distributions

PVG Cash Distributions

PVG paid cash distributions of $1.52 per common unit during the year ended December 31, 2009. In the first quarter of 2010, PVG paid a cash distribution of $0.38 ($1.52 on an annualized basis) per common unit with respect to the fourth quarter of 2009. This distribution was unchanged from the previous distribution paid on November 18, 2009. For the remainder of 2010, PVG expects to pay quarterly cash distributions of at least $0.38 ($1.52 on an annualized basis) per common unit.

PVR Cash Distributions

PVR paid cash distributions of $1.88 per common unit during the year ended December 31, 2009. In the first quarter of 2010, PVR paid a cash distribution of $0.47 ($1.88 on an annualized basis) per common unit with respect to the fourth quarter of 2009. This distribution was unchanged from the previous distribution paid on November 13, 2009. For the remainder of 2010, PVR expects to pay quarterly cash distributions of at least $0.47 ($1.88 on an annualized basis) per common unit.

PVR IDRs

In accordance with PVR's partnership agreement, IDRs represent the right to receive an increasing percentage of quarterly distributions of PVR's available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.25 ($1.00 on an annualized basis) per unit. PVR's general partner currently holds 100% of the IDRs, but may transfer these rights separately from its general partner interest to an affiliate (other than an individual) or to another entity as part of the merger or consolidation of PVR's general partner with or into such entity or the transfer of all or substantially all of PVR's general partner's assets to another entity without the prior approval of PVR's unitholders if the transferee agrees to be bound by the provisions of PVR's partnership agreement. Prior to September 30, 2011, other transfers of the IDRs will require the affirmative vote of holders of a majority of the outstanding PVR common units. On or after September 30, 2011, the IDRs will be freely transferable. The IDRs are payable as follows:

If for any quarter:

- PVR has distributed available cash from operating surplus to its common unitholders in an amount equal to the minimum quarterly distribution; and
- PVR has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, PVR will distribute any additional available cash from operating surplus for that quarter among the unitholders and its general partner in the following manner:

- First, 98% to all unitholders, and 2% to PVR's general partner, until each unitholder has received a total of $0.275 per unit for that quarter;
- Second, 85% to all unitholders, and 15% to PVR's general partner, until each unitholder has received a total of $0.325 per unit for that quarter;
- Third, 75% to all unitholders, and 25% to PVR's general partner, until each unitholder has received a total of $0.375 per unit for that quarter; and
- Thereafter, 50% to all unitholders and 50% to PVR's general partner.

Since 2001, PVR has increased its quarterly cash distribution from $0.25 ($1.00 on an annualized basis) per unit to $0.47 ($1.88 on an annualized basis) per unit, which is its most recently declared distribution. These increased cash distributions by PVR have placed PVG, as the owner of PVR's general partner, at the maximum target cash distribution level as described above and, as a consequence, since reaching such level, PVG, as the owner of PVR's general partner, has received 50% of available cash in excess of $0.375 per unit.

Cash Distributions Received

We are currently entitled to receive quarterly cash distributions from PVG and PVR on our limited partner interests in PVG and PVR. As a result of our partner interests in PVG and PVR, we received the following total cash distributions for the periods presented. The reduction in cash distributions we received from 2008 to 2009 was the result of our sale of a portion of our interest in PVG during 2009.

	Year Ended December 31,		
	2009	2008	2007
Penn Virginia GP Holdings, L.P.	$41,916	$43,435	$29,200
Penn Virginia Resource Partners, L.P.[1]	363	583	640
	$42,279	$44,018	$29,840

(1) Includes PVR distributions for restricted units held by employees and directors.

Competition

Oil and Gas Segment

The oil and natural gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop properties and our ability to select, acquire and develop proved reserves. We compete with other oil and natural gas companies to secure drilling rigs and other equipment necessary for the drilling and completion of wells and recruiting and retaining qualified personnel, including geologists, geo-physicists, engineers and other specialists. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. We also compete with substantially larger and independent oil and gas companies in the marketing and sale of oil and natural gas, and the oil and natural gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers.

PVR Coal and Natural Resource Management Segment

The coal industry is intensely competitive primarily as a result of the existence of numerous producers. PVR's lessees compete with both large and small coal producers in various regions of the United States for domestic sales. The industry has undergone significant consolidation which has led to some of the competitors of PVR's lessees having significantly larger financial and operating resources than most of PVR's lessees. PVR's lessees compete on the basis of coal price at the mine, coal quality (including sulfur content), transportation cost from the mine to the customer and the reliability of supply. Continued demand for PVR's coal and the prices that PVR's lessees obtain are also affected by demand for electricity, demand for metallurgical coal, access to transportation, environmental and government regulations, technological developments and the availability and price of alternative fuel supplies, including nuclear, natural gas, oil and hydroelectric power. Demand for PVR's low sulfur coal and the prices PVR's lessees will be able to obtain for it will also be affected by the price and availability of high sulfur coal, which can be marketed in tandem with emissions allowances which permit the high sulfur coal to meet federal Clean Air Act, or CAA, requirements.

PVR Natural Gas Midstream Segment

PVR experiences competition in all of its natural gas midstream markets. PVR's competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, process, transport and market natural gas. Many of PVR's competitors have greater financial resources and access to larger natural gas supplies than PVR does.

The ability to offer natural gas producers competitive gathering and processing arrangements and subsequent reliable service is fundamental to obtaining and keeping gas supplies for PVR's gathering systems. The primary concerns of the producer are:

- the pressure maintained on the system at the point of receipt;
- the relative volumes of gas consumed as fuel and lost;
- the gathering/processing fees charged;
- the timeliness of well connects;
- the customer service orientation of the gatherer/processor; and
- the reliability of the field services provided.

Government Regulation and Environmental Matters

The operations of our oil and gas business and PVR's coal and natural resource management and natural gas midstream businesses are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted.

Oil and Gas Segment

State Regulatory Matters. Various aspects of our oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These provisions include permitting regulations regarding the drilling of wells, maintaining bonding requirements to drill or operate wells, locating wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. The effect of these regulations is to limit the amounts of crude oil and natural gas we can produce from our wells and to limit the number of wells or the locations at which we can drill.

Federal Energy Regulatory Commission. The Federal Energy Regulatory Commission, or the FERC, regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act of 1938, or the NGA, and the Natural Gas Policy Act of 1978, or the NGPA. In the past, the federal government has regulated the prices at which oil and gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 removed all NGA and NGPA price and nonprice controls affecting producers' wellhead sales of natural gas effective January 1, 1993. While sales by producers of their own natural gas production and all sales of crude oil, condensate and NGLs can currently be made at market prices, Congress could reenact price controls in the future.

Commencing in April 1992, the FERC issued Order Nos. 636, 636-A, 636-B and 636-C, or Order No. 636, which require interstate pipelines to provide transportation separate, or "unbundled," from the pipelines' sale of gas. Also, Order No. 636 requires pipelines to provide open-access transportation on a basis that is equal for all gas supplies. Although Order No. 636 does not directly regulate gas producers like us, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify its open access regulations. In particular, the FERC has issued Order Nos. 637, 637-A and 637-B which, among other things, (i) permit pipelines to charge different maximum cost-based rates for peak and off-peak periods, (ii) encourage auctions for pipeline capacity, (iii) require pipelines to implement imbalance management services and (iv) restrict the ability of pipelines to impose penalties for imbalances, overruns and non-compliance with operational flow orders.

The Energy Policy Act of 2005 amended the NGA and the NGPA and gave the FERC the authority to assess civil penalties of up to $1 million per day per violation for violations of rules, regulations and orders issued under these acts. In addition, the FERC has issued regulations that make it unlawful for any entity in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the FERC to use any manipulative or deceptive device or contrivance.

While any additional FERC action on these matters would affect us only indirectly, these changes are intended to further enhance competition in, and prevent manipulation of, natural gas markets. We cannot predict what further action the FERC will take on these matters, nor can we predict whether the FERC's actions will achieve its stated goal of increasing competition in, and preventing manipulation of, natural gas markets. However, we do not believe that we will be treated materially differently than other natural gas producers with which we compete.

Environmental Matters. Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

As part of the 2008 Consolidated Appropriations Act, the EPA was required to issue a rule requiring mandatory reporting of greenhouse gas emissions above certain thresholds from all sectors of the U.S. economy. The proposed rule included greenhouse gas reporting requirements for oil and natural gas systems ("Subpart W"), including production and distribution facilities, but the EPA received extensive comments to Subpart W relating to the reporting of fugitive and vented emissions from the oil and gas sector. As a result, Subpart W was not included in the final rule. While the EPA may re-issue a proposed rule regarding the reporting of greenhouse gas emissions from oil and natural gas systems, we do not believe that any such future requirement will have a material adverse affect on our business, financial position or results of operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

PVR Coal and Natural Resource Management Segment

General Regulation Applicable to Coal Lessees. PVR's lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing polychlorinated biphenyls, or PCBs. These extensive and comprehensive regulatory requirements are closely enforced, PVR's lessees regularly have on-site inspections and violations during mining operations are not unusual in the industry, notwithstanding compliance efforts by PVR's lessees. However, none of the violations to date, or the monetary penalties assessed, have been material to us, PVR or, to our knowledge, to PVR's lessees. Although many new safety requirements have been instituted recently, PVR does not currently expect that future compliance will have a material adverse effect on PVR.

While it is not possible to quantify the costs of compliance by PVR's lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. We do not accrue for such costs because PVR's lessees are contractually liable for all costs relating to their mining operations, including the costs of reclamation and mine closure. However, PVR does require some smaller lessees to deposit into escrow certain funds for reclamation and mine closure costs or post performance bonds for these costs. Although we believe that the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. Compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities which could affect demand for coal mined by PVR's lessees. The possibility exists that new legislation or regulations may be adopted which have a significant impact on the mining operations of PVR's lessees or their customers' ability to use coal and may require PVR, its lessees or their customers to change operations significantly or incur substantial costs.

Air Emissions. The CAA and corresponding state and local laws and regulations affect all aspects of PVR's business, both directly and indirectly. The CAA directly impacts PVR's lessees' coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of recent federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under Environmental Protection Agency, or EPA, laws and regulations will make it more costly to build and operate coal-fired power plants and, depending on the requirements of individual state implementation plans, could make coal a less attractive fuel alternative in the planning and building of power plants in the future. Any reduction in coal's share of power generating capacity could negatively impact PVR's lessees' ability to sell coal, which could have a material effect on PVR's coal royalties revenues.

The EPA's Acid Rain Program, provided in Title IV of the CAA, regulates emissions of sulfur dioxide from electric generating facilities. Sulfur dioxide is a by-product of coal combustion. Affected facilities purchase or are otherwise allocated sulfur dioxide emissions allowances, which must be surrendered annually in an amount equal to a facility's sulfur dioxide emissions in that year. Affected facilities may sell or trade excess allowances to other facilities that require additional allowances to offset their sulfur dioxide emissions. In addition to purchasing or trading for additional sulfur dioxide allowances, affected power facilities can satisfy the requirements of the EPA's Acid Rain Program by switching to lower sulfur fuels, installing pollution control devices such as flue gas desulfurization systems, or "scrubbers," or by reducing electricity generating levels.

The EPA has promulgated rules, referred to as the "NOx SIP Call," that require coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule, or CAIR, which would have permanently capped nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. beginning in 2009 and 2010. CAIR required those states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered "cap-and-trade" program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state. The stringency of the caps under CAIR may have required many coal-fired sources to install additional pollution control equipment, such as wet scrubbers, to comply. This increased sulfur emission removal capability required by CAIR could have resulted in decreased demand for lower sulfur coal, which may have potentially driven down prices for lower sulfur coal. On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety. The EPA subsequently filed a petition for rehearing or, in the alternative, for a remand of the case without vacatur. On December 23, 2008, the Court issued an opinion to remand without vacating CAIR. Therefore, CAIR will remain in effect while the EPA conducts rulemaking to modify CAIR to comply with the Court's July 2008 opinion. The Court declined to impose a schedule by which the EPA must complete the rulemaking, but reminded the EPA that the Court does ".not intend to grant an indefinite stay of the effectiveness of this Court's decision." The EPA is considering its options on how to proceed.

In March 2005, the EPA finalized the Clean Air Mercury Rule, or CAMR, which was to establish a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. It was the subject of extensive controversy and litigation and, in February 2008, the U.S. Circuit Court of Appeals for the District of Columbia vacated CAMR. The EPA appealed the decision to the U.S. Supreme Court in October 2008, but withdrew its petition for certiorari on February 6, 2009. However, a utility group continues to seek certiorari, challenging the court of appeals decision to overturn CAMR. In the meantime, the EPA plans to develop standards consistent with the court of appeal's ruling, intending to propose air toxics standards for coal- and oil-fired electric generating units by March 10, 2011, and finalize a rule by November 16, 2011. In conjunction with these efforts, on December 24, 2009, the EPA approved an Information Collection Request (ICR) requiring all U.S. power plants with coal-or oil-fired electric generating units to submit emissions information for use in developing air toxics emissions standards. In addition, various states have promulgated or are considering more stringent emission limits on mercury emissions from coal-fired electric generating units.

The EPA has adopted new, more stringent national air quality standards for ozone and fine particulate matter. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. In March 2007, the EPA published final rules addressing how states would implement plans to bring regions designated as non-attainment for fine particulate matter into compliance with the new air quality standard. Under the EPA's final rule, states had until April 2008 to submit their implementation plans to the EPA for approval. Because coal mining operations and coal-fired electric generating facilities emit particulate matter, PVR's lessees' mining operations and their customers could be affected when the new standards are implemented by the applicable states.

Likewise, the EPA's regional haze program to improve visibility in national parks and wilderness areas required affected states to develop implementation plans by December 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the new source review provisions of the CAA. The EPA has alleged that certain modifications have been made to these facilities without first obtaining permits required under the new source review program. Several of these lawsuits have settled, but others remain pending. On April 2, 2007, the U.S. Supreme Court ruled in one such case, *Environmental Defense v. Duke Energy Corp.* The Court held that the EPA is not required to use an "hourly rate test" in determining whether a modification to a coal burning utility requires a permit under the new source review program, thus allowing the EPA to apply a test based on average annual emissions. The use of an annual emissions test could subject more coal-fired utility modification projects to the permitting requirements of the CAA New Source Review Program, such as those that allow plants to run for more hours in a given year. However, Duke is expected to continue to contest remaining issues in the case, and so litigation in this and other pending cases will likely continue. Depending on the ultimate resolution of these cases, demand for PVR's coal could be affected, which could have an adverse effect on PVR's coal royalties revenues.

Carbon Dioxide Emissions. The Kyoto Protocol to the United Nations Framework Convention on Climate Change calls for developed nations to reduce their emissions of greenhouse gases to 5% below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty. In 2002, the United States withdrew its support for the Kyoto Protocol, and the United States is not participating in this treaty. Since the Kyoto Protocol became effective, there has been increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. In addition, on April 2, 2007 the U.S. Supreme Court held in *Massachusetts v. EPA* that unless the EPA affirmatively concludes that greenhouse gases are not causing climate change, the EPA must regulate greenhouse gas emissions from new automobiles under the CAA. The Court remanded the matter to the EPA for further consideration. This litigation did not directly concern the EPA's authority to regulate greenhouse gas emissions from stationary sources, such as coal mining operations or coal-fired power plants. However, the Court's decision is likely to influence another lawsuit currently pending in the U.S. Court of Appeals for the District of Columbia Circuit, involving a challenge to the EPA's decision not to regulate carbon dioxide from power plants and other stationary sources under a CAA new source performance standard rule, which specifies emissions limits for new facilities. The court remanded that question to the EPA for further consideration in light of the ruling in *Massachusetts v. EPA*. On July 11, 2008, the EPA released an advanced notice of proposed rulemaking to regulate greenhouse gases under the CAA in response to the ruling in *Massachusetts v. EPA*. The notice did not contain a definitive proposal of what a greenhouse gas regulatory program would look like, but it presented the EPA's analyses and policy alternatives for consideration. The EPA stated that promulgating a program under the CAA would take years to issue. In 2009, EPA took further steps toward greenhouse gas regulation under the CAA, issuing a final rule declaring that six greenhouse gases, including carbon dioxide and methane, "endanger both the public health and the public welfare of current and future generations." The issuance of this "endangerment finding" allows the EPA to begin regulating greenhouse gas emissions under existing provisions of CAA. In late September and early October of 2009, in anticipation of the issuance of the endangerment finding, the EPA officially proposed two sets of rules regarding possible future regulation of greenhouse gas emissions under the CAA, one that would regulate greenhouse gas emissions from motor vehicles and the other greenhouse gas emissions from large stationary sources such as power plants or industrial facilities. Any decision in this case or any regulatory action by the EPA limiting greenhouse gas emissions from power plants could impact the demand for PVR's coal, which could have an adverse effect on PVR's coal royalties revenues.

The permitting of a number of proposed new coal-fired power plants has also recently been contested by environmental organizations for concerns related to greenhouse gas emissions from new plants. For instance, in October 2007, state regulators in Kansas became the first to deny an air emissions construction permit for a new coal-fired power plant based on the plant's projected emissions of carbon dioxide. State regulatory authorities in Florida and North Carolina have also rejected the construction of new coal-fired power plants based on the uncertainty surrounding the potential costs associated with greenhouse gas emissions from these plants under future laws limiting the emission of carbon dioxide.

In addition, permits for several new coal-fired power plants without limits imposed on their greenhouse gas emissions have been appealed by environmental organizations to the EPA's Environmental Appeals Board, or EAB, and other judicial forums under the CAA. For example, in June 2008, a Georgia court voided a CAA permit and halted the construction of a coal-fired power plant for failure to address carbon dioxide emissions. Likewise, in November 2008, in another case, *In re Deseret Power Electric Cooperative*, the EAB remanded the permitting decision back to the Region to reopen the record and reconsider whether carbon dioxide is a pollutant subject to regulation under the CAA with instructions to consider its nationwide implications. In December 2008, the EPA Administrator issued an interpretive rule determining the phrase in the CAA "not subject to regulation" does not include pollutants for which only monitoring and reporting is required. Because carbon dioxide is such a pollutant, this interpretive rule has the effect of precluding any consideration of carbon dioxide emissions in connection with federal permitting under the CAA. Environmental groups filed a Petition for Reconsideration of the interpretive rule. On February 17, 2009, the EPA stated that it would grant the Petition for Reconsideration and allow public comment, but it declined to stay the effectiveness of the interpretive rule at that time.

A number of states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, ten northeastern and mid-Atlantic states have agreed to implement a regional cap-and-trade program, referred to as the Regional Greenhouse Gas Initiative, or RGGI, to stabilize carbon dioxide emissions from regional power plants beginning in 2009. This initiative aims to reduce emissions of carbon dioxide to levels roughly corresponding to average annual emissions between 2000 and 2004. The members of RGGI agreed to seek to establish in statute and/or regulation a carbon dioxide trading program and have each state's component of the regional program effective no later than December 31, 2008. Auctions for carbon dioxide allowances under the program began in September 2008. Following the RGGI model, seven Western states and four Canadian provinces have also formed a regional greenhouse gas reduction initiative known as the Western Regional Climate Action Initiative, which calls for an overall reduction of regional greenhouse gas emissions from major industrial and commercial sources, including fossil-fuel fired power plants, in participating states through trading of emissions credits beginning in 2012. Similarly, in 2007, six Midwestern states and one Canadian province signed the Midwestern Greenhouse Gas Reduction Accord to develop and implement steps to reduce greenhouse gas emissions, including developing a market-based, multi-sector cap. Some states have passed laws individually. For example, in 2006, the governor of California signed Assembly Bill 32 into law, requiring the California Air Resources Board to develop regulations and market mechanisms to reduce California's greenhouse gas emissions by 25% by 2020 with mandatory caps beginning in 2012 for significant sources. In 2007, New Jersey passed a greenhouse gas reduction that would be economy wide, requiring emissions to drop to 1990 levels by 2020 and that emissions be capped at 80% of 2006 levels by 2050.

At the federal level, legislation was introduced in Congress in 2007, 2008 and 2009 to reduce greenhouse gas emissions in the United States. Such or similar federal legislation, which generally seeks to place an economy-wide cap on emissions of greenhouse gases and would require most sources of greenhouse gas emissions to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases, could be taken up in 2010 or later years. It is possible that future federal and state initiatives to control and put a price on carbon dioxide emissions, or otherwise regulate greenhouse gas emissions, could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact PVR's lessees' coal sales, and thereby have an adverse effect on PVR's coal royalties revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977, or SMCRA, and similar state statutes establish minimum national operational, reclamation and closure standards for all aspects of surface mining, as well as most aspects of deep mining. SMCRA requires that comprehensive environmental protection and reclamation standards be met during the course of and following completion of mining activities. SMCRA also imposes on mine operators the responsibility of restoring the land to its original state and compensating the landowner for types of damages occurring as a result of mining operations, and requires mine operators to post performance bonds to ensure compliance with any reclamation obligations. Moreover, regulatory authorities may attempt to assign the liabilities of PVR's coal lessees to another entity such as PVR if any of its lessees are not financially capable of fulfilling those obligations on the theory that PVR "owned" or "controlled" the mine operator in such a way for liability to attach. To our knowledge, no such claims have been asserted against PVR to date. In conjunction with mining the property, PVR's coal lessees are contractually obligated under the terms of their leases to comply with all state and local laws, including SMCRA, with obligations including the reclamation and restoration of the mined areas by grading, shaping and reseeding the soil. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan. Additionally, the Abandoned Mine Lands Program, which is part of SMCRA, imposes a tax on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The maximum tax is 31.5 cents per ton on surface-mined coal and 13.5 cents per ton on underground-mined coal. This tax was set to expire on June 30, 2006, but the program was extended until September 30, 2021.

Federal and state laws require bonds to secure PVR's lessees' obligations to reclaim lands used for mining and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for mining companies to secure new surety bonds without the posting of partial collateral. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable. It is possible that surety bonds issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Any failure to maintain, or inability to acquire, surety bonds that are required by state and federal laws would have a material adverse effect on PVR's lessees' ability to produce coal, which could affect PVR's coal royalties revenues.

Hazardous Materials and Wastes. The Federal Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, or the Superfund law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Some products used by coal companies in operations generate waste containing hazardous substances. PVR could become liable under federal and state Superfund and waste management statutes if its lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek recovery from the responsible classes of persons of the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. The Resource Conservation and Recovery Act, or RCRA, and corresponding state laws and regulations exclude many mining wastes from the regulatory definition of hazardous wastes. Currently, the management and disposal of coal combustion by-products are also not regulated at the federal level and not uniformly at the state level. If rules are adopted to regulate the management and disposal of these by-products, they could add additional costs to the use of coal as a fuel and may encourage power plant operators to switch to a different fuel.

Clean Water Act. PVR's coal lessees' operations are regulated under the Clean Water Act, or the CWA, with respect to discharges of pollutants, including dredged or fill material into waters of the United States. Individual or general permits under Section 404 of the CWA are required to conduct dredge or fill activities in jurisdictional waters of the United States. Surface coal mining operators obtain these permits to authorize such activities as the creation of slurry ponds, stream impoundments and valley fills. Uncertainty over what legally constitutes a navigable water of the United States within the CWA's regulatory scope may adversely impact the ability of PVR's coal lessees to secure the necessary permits for their mining activities. Some surface mining activities require a CWA Section 404 "dredge and fill" permit under the CWA for valley fills and the associated sediment control ponds. On June 5, 2007, in response to the U.S. Supreme Court's divided opinion in *Rapanos v. United States*, the EPA and the U.S. Army Corps of Engineers, or the Corps, issued joint guidance to EPA regions and Corps districts interpreting the geographic extent of regulatory jurisdiction under Section 404 of the CWA. Specifically, the guidance places jurisdictional water bodies into two groups: waters where the agencies will assert regulatory jurisdiction "categorically" and waters where the agencies will assert jurisdiction on a case-by-case basis following a "significant nexus analysis." It remains to be seen how this guidance will affect the permitting process for obtaining additional permits for valley fills and sediment ponds although it is likely to add uncertainty and delays in the issuance of new permits. Some valley fill surface mining activities have the potential to impact headwater streams that are not relatively permanent, which could therefore trigger a detailed "significant nexus analysis" to determine whether a Section 404 permit would be required. Such analyses could require the extensive collection of additional field data and could lead to delays in the issuance of CWA Section 404 permits for valley fill surface mining operations.

Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created additional uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. The Corps is authorized by Section 404 of the CWA to issue "nationwide" permits for specific categories of dredging and filling activities that are similar in nature and that are determined to have minimal adverse environmental effects. Nationwide Permit 21 authorizes the disposal of dredged or fill material from surface coal mining activities into the waters of the United States. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the Corps from issuing further permits pursuant to Nationwide Permit 21. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, it has been remanded to the District Court for the Southern District of West Virginia for further proceedings. Moreover, a similar lawsuit has been filed in the U.S. District Court for the Eastern District of Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the Corps.

In the event similar lawsuits prove to be successful in adjoining jurisdictions, PVR's lessees may be required to apply for individual discharge permits pursuant to Section 404 of the CWA in areas where they would have otherwise utilized Nationwide Permit 21. Such a change could result in delays in PVR's lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on PVR's coal royalties revenues.

Individual CWA Section 404 permits for valley fills associated with surface mining activities are also subject to certain legal challenges and uncertainty. On September 22, 2005, in the case *Ohio Valley Environmental Coalition ("OVEC") v. United States Army Corps of Engineers*, environmental group plaintiffs filed suit in the U.S. District Court for the Southern District of West Virginia challenging the Corps' decision to issue individual CWA Section 404 permits for certain mining projects. Alex Energy, Inc., or Alex Energy, a lessee of PVR that operates the Republic No. 2 Mine in Kanawha County, West Virginia, intervened as a defendant in this litigation when the plaintiffs' amended their complaint to add the December 22, 2005 individual CWA Section 404 permit for the Republic No. 2 Mine, or the Republic No. 2 Permit. On March 23, 2007, the district court rescinded several challenged CWA Section 404 permits, including the Republic No. 2 Permit, and remanded the permit applications to the Corps for further proceedings. In addition, the district court enjoined the permit holders, including Alex Energy, from all activities authorized under the rescinded permits. As part of the *OVEC* litigation, the environmental groups have also challenged the CWA Section 404 permit issued to Alex Energy for the Republic No. 1 Mine, also located in Kanawha County, West Virginia.

The Corps, Alex Energy, other impacted mining companies, and mining associations appealed the March 23, 2007 ruling to the U.S. Court of Appeals for the Fourth Circuit. On February 13, 2009, the Fourth Circuit reversed and vacated the District Court's March 23, 2007 opinion and order that had rescinded the challenged permits and vacated the District Court's injunction of activity under those permits and reversed a related order by the District Court that would have required yet additional permits under the CWA. One of the three judges dissented in part from this decision and would have upheld the decision rescinding the permits and enjoining future activity but agreed with the other two judges on the other parts of the decision. This decision may be subject to further appellate review including by the Fourth Circuit itself. We are unable to predict the outcome of any further appellate review that may be obtained.

In December 2007, plaintiff environmental groups brought a similar suit against the issuance of a CWA Section 404 permit for a surface coal mine in the U.S. District Court for the Eastern District of Kentucky, alleging identical violations. The Corps has voluntarily suspended its consideration of the permit application in that case for agency re-evaluation. While the final outcome of these cases remains uncertain, if lawsuits challenging the use of valley fills ultimately limits or prohibits the mining methods or operations of PVR's lessees, it could have an adverse effect on PVR's coal royalties revenues. In addition, it is possible that similar litigation affecting recently issued, pending or future individual or general CWA Section 404 permits relevant to the mining and related operations of PVR's lessees could adversely impact PVR's coal royalties revenues.

In December 2008, the Department of Interior published the Excess Spoil, Coal Mine Waste and Buffers for Perennial and Intermittent Streams rule under SMCRA in part to clarify when valley fills are permitted. The rule would require a 100-foot buffer around all waters, including streams, lakes, ponds and wetlands. However, the rule would exempt certain activities, such as permanent spoil fills and coal waste disposal facilities, and allow mining that changes a waterway's flow, providing the mining company repairs damage later. Companies could also receive a permit to dispose of waste within the buffer zone if they explain why an alternative is not reasonably possible or is not necessary to meet environmental requirements. Environmental groups have brought lawsuits challenging the rule. It is unclear what impact the rule will have on the previously discussed lawsuits related to valley fills or any mining operations undertaken by PVR's lessees in the future.

Total Maximum Daily Load, or TMDL, regulations under the CWA establish a process to calculate the maximum amount of a pollutant that a water body can receive and still meet state water quality standards and to allocate pollutant loads among the point- and non-point pollutant sources discharging into that water body. This process applies to those waters that states have designated as impaired (not meeting present water quality standards). Industrial dischargers, including coal mines, discharging to such waters will be required to meet new TMDL allocations for these stream segments. The adoption of new TMDL-related allocations for streams to which PVR's lessees' coal mining operations discharge could require more costly water treatment and could adversely affect PVR's lessees' coal production.

The CWA also requires states to develop anti-degradation policies to ensure non-impaired water bodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict PVR's lessees' ability to develop new mines or could require PVR's lessees to modify existing operations, which could have an adverse effect on PVR's coal business.

The Safe Drinking Water Act, or the SDWA, and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of "public water systems." This regulatory program could impact PVR's lessees' reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

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

Mine Health and Safety Laws. The operations of PVR's coal lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, as part of the Mine Health and Safety Acts of 1969 and 1977, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Recent mining accidents in West Virginia and Kentucky have received national attention and instigated responses at the state and national level that are likely to result in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. On March 7, 2006, New Mexico Governor Bill Richardson signed into law an expanded miner safety program including more stringent requirements for accident reporting and the installation of additional mine safety equipment at underground mines. Similarly, on April 27, 2006, Kentucky Governor Ernie Fletcher signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006, the President signed the "Miner Act," which was new mining safety legislation that mandates improvements in mine safety practices, increases civil and criminal penalties for non-compliance, requires the creation of additional mine rescue teams and expands the scope of federal oversight, inspection and enforcement activities. Pursuant to the Miner Act, the Mine Safety Health Administration, or MSHA, has promulgated new emergency rules on mine safety and revised MSHA's civil penalty assessment regulations, which resulted in an across-the-board increase in penalties from the existing regulations. These requirements may add significant costs to PVR's lessees' operations, particularly for underground mines, and could affect the financial performance of PVR's lessees' operations.

Implementing and complying with these new laws and regulations could adversely affect PVR's lessees' coal production and could therefore have an adverse effect on PVR's coal royalties revenues.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, PVR's coal lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

Under some circumstances, substantial fines and penalties, including revocation of mining permits, may be imposed under the laws described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations which have outstanding environmental violations. Although, like other coal companies, PVR's lessees' have been cited for violations in the ordinary course of business, to our knowledge, none of them have had one of their permits suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including PVR's lessees, must submit a reclamation plan for restoring, upon the completion of mining operations, the mined property to its prior condition, productive use or other permitted condition. Typically, PVR's lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In PVR's experience, permits generally are approved within 12 months after a completed application is submitted. In the past, PVR's lessees have generally obtained their mining permits without significant delay. PVR's lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined over the next five years. PVR's lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, there are no assurances that they will not experience difficulty in obtaining mining permits in the future. See "— PVR Coal and Natural Resource Management Segment — Clean Water Act."

OSHA. PVR's lessees and PVR's own business are subject to OSHA. See "— Oil and Gas Segment — OSHA."

PVR Natural Gas Midstream Segment

General Regulation. PVR's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but FERC regulation nevertheless could significantly affect PVR's gathering business and the market for its services. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines into which PVR's gathering pipelines deliver. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

For example, the FERC will assert jurisdiction over an affiliated gatherer that acts to benefit its pipeline affiliate in a manner that is contrary to the FERC's policies concerning jurisdictional services adopted pursuant to the NGA. In addition, natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a less stringent approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. PVR's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. PVR's gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on PVR's natural gas midstream operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

In Texas, PVR's gathering facilities are subject to regulation by the Texas Railroad Commission, which has the authority to ensure that rates, terms and conditions of gas utilities, including certain gathering facilities, are just and reasonable and not discriminatory. PVR's operations in Oklahoma are regulated by the Oklahoma Corporation Commission, which prohibits PVR from charging any unduly discriminatory fees for its gathering services. We cannot predict whether PVR's gathering rates will be found to be unjust, unreasonable or unduly discriminatory.

PVR is subject to ratable take and common purchaser statutes in Texas and Oklahoma. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting PVR's right as an owner of gathering facilities to decide with whom it contracts to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and Texas and Oklahoma have adopted complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering rates and access. We cannot assure you that federal and state authorities will retain their current regulatory policies in the future.

Texas and Oklahoma administer federal pipeline safety standards under the Natural Gas Pipeline Safety Act of 1968, or the NGPSA, which requires certain natural gas pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. PVR also operates a NGL pipeline that is subject to regulation by the U.S. Department of Transportation under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. In response to recent pipeline accidents, Congress and the U.S. Department of Transportation have instituted heightened pipeline safety requirements. Certain of PVR's gathering facilities are exempt from these federal pipeline safety requirements under the rural gathering exemption. We cannot assure you that the rural gathering exemption will be retained in its current form in the future.

Failure to comply with applicable regulations under the NGA, the NGPSA and certain state laws can result in the imposition of administrative, civil and criminal remedies.

Air Emissions. PVR's natural gas midstream operations are subject to the CAA and comparable state laws and regulations. See "— PVR Coal and Natural Resource Management Segment — Air Emissions." These laws and regulations govern emissions of pollutants into the air resulting from the activities of PVR's processing plants and compressor stations and also impose procedural requirements on how PVR conducts its natural gas midstream operations. Such laws and regulations may include requirements that PVR obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, strictly comply with the emissions and operational limitations of air emissions permits PVR is required to obtain or utilize specific equipment or technologies to control emissions. PVR's failure to comply with these requirements could subject it to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. PVR will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Hazardous Materials and Wastes. PVR's natural gas midstream operations could incur liability under CERCLA and comparable state laws resulting from the disposal or other release of hazardous substances or wastes originating from properties PVR owns or operates, regardless of whether such disposal or release occurred during or prior to PVR's acquisition of such properties. See "— PVR Coal and Natural Resource

Management Segment — Hazardous Materials and Wastes." Although petroleum, including natural gas and NGLs are generally excluded from CERCLA's definition of "hazardous substance," PVR's natural gas midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a CERCLA "hazardous substance," or be subject to regulation under state laws.

PVR's natural gas midstream operations generate wastes, including some hazardous wastes, which are subject to RCRA and comparable state laws. However, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. Unrecovered petroleum product wastes, however, may still be regulated under RCRA as solid waste. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas and NGLs in pipelines may also generate some hazardous wastes. Although PVR believes that it is unlikely that the RCRA exemption will be repealed in the near future, repeal would increase costs for waste disposal and environmental remediation at PVR's facilities.

PVR currently owns or leases numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas and NGLs. Although PVR believes that the operators of such properties used operating and disposal practices that were standard in the industry at the time, hydrocarbons or wastes may have been disposed of or released on or under such properties or on or under other locations where such wastes have been taken for disposal. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, PVR could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination, whether from prior owners or operators or other historic activities or spills) or to perform remedial plugging or pit closure operations to prevent future contamination. PVR has ongoing remediation projects underway at several sites, but it does not believe that the costs associated with such cleanups will have a material adverse impact on PVR's operations or revenues.

Water Discharges. PVR's natural gas midstream operations are subject to the CWA. See "— PVR Coal and Natural Resource Management Segment — Clean Water Act." Any unpermitted release of pollutants, including NGLs or condensates, from PVR's systems or facilities could result in fines or penalties as well as significant remedial obligations.

OSHA. PVR's natural gas midstream operations are subject to OSHA. See "— Oil and Gas Segment — OSHA."

Employees and Labor Relations

We and our subsidiaries had a total of 382 employees at December 31, 2009, including 167 employees who directly supported PVR's operations. We consider our current employee relations to be favorable.

Available Information

Our internet address is *http://www.pennvirginia.com.* We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our 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 Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. All references in this Annual Report on Form 10-K to the "NYSE" refer to the New York Stock Exchange, and all references to the "SEC" refer to the Securities and Exchange Commission.

Common Abbreviations and Definitions

The following are abbreviations and definitions commonly used in the coal and oil and gas industries that are used in this Annual Report on Form 10-K.

Bbl	a standard barrel of 42 U.S. gallons liquid volume
Bcf	one billion cubic feet
Bcfe	one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
BTU	British thermal unit
CBM	coalbed methane
Developed acreage	lease acreage that is allocated or assignable to producing wells or wells capable of production
Development well	a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive
Dry hole	a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well
Exploratory or exploration well	a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir
GAAP	accounting principles generally accepted in the Unites States of America
Gross acre or well	an acre or well in which a working interest is owned
MBbl	one thousand barrels
Mbf	one thousand board feet
Mcf	one thousand cubic feet
Mcfe	one thousand cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
MMBbl	one million barrels
MMbf	one million board feet
MMBtu	one million British thermal units
MMcf	one million cubic feet
MMcfd	one million cubic feet per day
MMcfe	one million cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
Net acre or well	gross acres or wells multiplied by the owned working interest in those gross acres or wells
NGL	natural gas liquid
NYMEX	New York Mercantile Exchange
Present value of proved reserves	the present value (discounted at 10%) of estimated future cash flows from proved oil and natural gas reserves, as estimated by our independent engineers, reduced by additional estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith (before income taxes)

Probable coal reserves	those reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are more widely spaced or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation
Productive wells	wells that are producing oil or gas or that are capable of production
Proved reserves	those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate
Proved developed reserves	proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well
Proved undeveloped reserves	proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.
Proven coal reserves	those reserves for which: (i) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; (ii) grade and/or quality are computed from the results of detailed sampling; and (iii) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well established
Standardized measure	present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using the average prices during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated future costs as of that fiscal year end. Prices are held constant throughout the life of the properties except where SEC guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.
Undeveloped acreage	lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated net proved reserves
Working interest	a cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease

Item 1A Risk Factors

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition or results of operations. If any of the following risks actually occur, our business, financial condition or results of operations could suffer.

Risks Related to Our Oil and Gas Business

Natural gas and crude oil prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, cash flow, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for natural gas and crude oil. Historically, natural gas and crude oil prices have been volatile, and they are likely to continue to be volatile. Wide fluctuations in natural gas and crude oil prices may result from relatively minor changes in the supply of and demand for oil and gas, market demand and other factors that are beyond our control, including:

- domestic and foreign supplies of oil and natural gas;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of alternative fuels;
- the availability of transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

Some of our projections and estimates are based on assumptions as to the future prices of natural gas and crude oil. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates. Any substantial or extended decline in the actual prices of natural gas or crude oil would have a material adverse effect on our financial position and results of operations (including reduced cash flow and borrowing capacity and possible asset impairment), the quantities of natural gas and crude oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves primarily through exploration and development and, to a lesser extent, acquisitions. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. The currently depressed oil and gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital remain limited or unavailable due to the deterioration of the global economy, including financial and credit markets. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities. However, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. Depending on the longevity of the deterioration of the market, our ability to make acquisitions may be significantly adversely affected. In the event we are successful in completing an acquisition, we cannot ensure that such acquisition will consist of properties that contain economically recoverable reserves or that such acquisition will be profitably integrated into our operations.

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures to find, acquire, develop, exploit and produce oil and natural gas reserves. In 2010, we anticipate making oil and gas segment capital expenditures, excluding acquisitions, of up to approximately $425 million. This is $253 million, or 147%, higher than the $172 million of capital expenditures, excluding acquisitions, that our oil and gas segment made in 2009.

If oil and gas prices decrease or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce the capital we can spend unless we raise additional funds through debt or equity financing. The current global economic downturn may adversely impact our ability to issue additional equity in the future at prices which will not be dilutive to our existing shareholders or preclude us from issuing equity at all. In addition, debt financing may not be available if needed and to the extent required, on acceptable terms.

Future cash flows and the availability of financing will also be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and prices of oil and natural gas.

If our revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through the Revolver, or otherwise, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive natural gas or oil reserves will be found. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- shortages or delays in the availability of drilling rigs and the delivery of equipment;
- shortages in experienced labor;
- failure to secure necessary regulatory approvals and permits;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of oil and gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that natural gas or oil is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business results of operations or financial condition. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by our customers would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues from our oil and gas segment. In 2009, 25% of our oil and gas segment revenues and 7% of our total consolidated revenues resulted from two of our oil and gas customers. Any nonpayment or nonperformance by our oil and gas customers would reduce our cash flows.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and natural gas. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- natural disasters.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, results of operations or financial condition.

Our business depends on transportation facilities owned by others.

We deliver substantially all of our oil and natural gas production through pipelines that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines as well as gathering systems and processing facilities. The unavailability or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and market our oil and natural gas.

Estimates of oil and natural gas reserves are not precise.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

At December 31, 2009, approximately 53% of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

The oil and gas segment may record impairment losses on its oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives on certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be sufficient enough to cause impairment losses on certain properties that would result in a further non-cash expense to earnings.

If natural gas, crude oil and NGL prices decline or we drill uneconomic wells, it is reasonably possible we will have a significant impairment.

We have limited control over the activities on properties we do not operate.

In 2009, other companies operated approximately 35% of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Certain working interest owners in our properties have the right to control the timing of drilling activities on our properties under certain circumstances.

Under certain circumstances, certain of the other working interest owners in our properties have the right to limit the amount of drilling activities that can take place on our properties at any given time. If these working interest owners chose to exercise this right, we could be required to scale back anticipated drilling activities on the affected properties. In such an event, production from the affected properties would be deferred, thereby decreasing production from the properties in the short-term.

Our producing property acquisitions carry significant risks.

Acquisition of producing oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. Depending on the longevity of the deterioration of the market, our ability to make acquisitions may be significantly adversely affected. In the event we do complete an acquisition, its success will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future oil and gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the sale of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains if oil or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how oil or natural gas prices fluctuate in the future.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations or financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition or results of operations. See Item 1, "Business — Government Regulation and Environmental Matters — Oil and Gas Segment — Environmental Matters."

Risks Related to Our Ownership Interests in PVG and PVR

We may sell all or a part of our remaining partner interest in PVG.

In September 2009, we sold approximately one-third of our limited partner interest in PVG, and we continue to own the general partner interest and an approximately 51% limited partner interest in PVG. We may sell all or a portion of our remaining interests in PVG in one or more transactions. We cannot be certain of whether or when any such sales may occur or, if they do, the amount of proceeds they would generate. However, if we sell all or a part of our interests in PVG, we will likely incur additional general and administrative costs related to costs and services which, prior to such sale, were paid for, in part, by affiliates of PVG.

A reduction in PVR's distributions will disproportionately affect the amount of cash distributions to which PVG is currently entitled, and, consequently, will affect the amount of cash distributions PVG is able to make to its unitholders, including us.

PVG and PVR are publicly traded limited partnerships. We own PVG GP, LLC, the sole general partner of PVG. As of December 31, 2009, we also owned an approximately 51.4% limited partner interest in PVG. As of December 31, 2009, PVG owned an approximately 37% limited partner interest in PVR, as well as 100% of the general partner of PVR, which owns a 2% general partner interest and the IDRs. We directly owned an additional 0.1% limited partner interest in PVR as of December 31, 2009.

PVG's ownership of the IDRs in PVR through PVG's ownership of PVR's general partner, entitles it to receive increasing percentages, up to 50%, of incremental cash distributions above $0.375 per unit distributed by PVR on a quarterly basis. A decrease in the amount of distributions by PVR to less than $0.375 per unit per quarter would reduce PVG's percentage of the incremental cash distributions above $0.325 per common unit per quarter from 50% to 25%, consequently resulting in less cash available to PVG to distribute to its unitholders, including us.

PVG and PVR's respective partnership agreements require them to distribute, on a quarterly basis, 100% of their available cash to their respective unitholders of record and their respective general partners. For each of PVG and PVR, available cash is generally all cash on hand at the end of each quarter, after payment of fees and expenses and the establishment of cash reserves by their respective general partners.

PVG's and PVR's general partners determine the amount and timing of cash distributions by PVG and PVR and have broad discretion to establish and make additions to the respective partnership's reserves in amounts the general partner determines to be necessary or appropriate:

- to provide for the proper conduct of partnership business, and in the case of PVR, the businesses of its operating subsidiaries (including reserves for future capital expenditures and for anticipated future credit needs);
- to provide funds for distributions to the respective unitholders and the respective general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any loan or other agreements.

A decrease in the amount of distributions by PVR and, consequently, PVG may be caused by a variety of circumstances. PVR may generate less cash available for distributions or determine to create larger reserves in computing cash available for distribution. Even if cash available for distribution remained stable, PVG and PVR may determine to modify the IDRs to reduce the percentage of incremental cash distributions such IDRs are entitled to receive. Accordingly, cash distributions we receive on our partner interests in PVG and PVR may be reduced at any time, or we may not receive any cash distributions from PVG or PVR, which would in turn reduce our available cash.

PVG's ability to make distributions to us is entirely dependent upon PVG receiving distributions from PVR, and the amount of cash that PVR will be able to distribute to its unitholders, including PVG, principally depends upon the amount of cash it can generate from its coal and natural resource management and natural gas midstream businesses.

PVG's earnings and cash flow consist exclusively of cash distributions from PVR. Consequently, a significant decline in PVR's earnings or cash distributions would have a negative impact on its distributions to its partners, including us. The amount of cash that PVR will be able to distribute to its partners, including PVG, each quarter principally depends upon the amount of cash it can generate from its coal and natural resource management and natural gas midstream businesses. The amount of cash that PVR will generate will fluctuate from quarter to quarter based on, among other things:

- the amount of coal its lessees are able to produce;
- the price at which its lessees are able to sell the coal;
- its lessees' timely receipt of payment from their customers;
- PVR's timely receipt of payment from its lessees;
- the amount of natural gas transported in its gathering systems;
- the amount of throughput in its processing plants;
- the price of and demand for natural gas;
- the price of and demand for NGLs;
- the relationship between natural gas and NGL prices;

- the fees it charges and the margins it realizes for its natural gas midstream services; and
- its hedging activities.

In addition, the actual amount of cash that PVR will have available for distribution will depend on other factors, including:

- the level of capital expenditures it makes;
- the cost of acquisitions, if any;
- its debt service requirements;
- fluctuations in its working capital needs;
- restrictions on distributions contained in its debt agreements;
- prevailing economic conditions; and
- the amount of cash reserves established by its general partner in its sole discretion for the proper conduct of its business.

Because of these factors, PVR may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. If PVR reduces its per unit distribution, PVG will have less cash available for distribution to its unitholders, including us, and would probably be required to reduce its per unit distribution to its unitholders, including us. The amount of cash that PVR has available for distribution depends primarily upon PVR's cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, PVR may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Since PVR's inception as a publicly traded partnership, it has grown principally by making acquisitions in both of its business segments and, to a lesser extent, by organic growth on its properties. Readily available access to debt and equity capital and credit availability have been and continue to be critical factors in PVR's ability to grow. The current state of the global economy and the consequential adverse effect on credit availability may adversely impact PVR's access to new capital and credit availability. Depending on the longevity and ultimate severity of this downturn, PVR's ability to make acquisitions may be significantly adversely affected, as may PVR's ability to make cash distributions to its unitholders.

In addition, the timing and amount, if any, of an increase or decrease in distributions by PVR to its unitholders will not necessarily be comparable to the timing and amount of any changes in distributions made by PVG. PVG's ability to distribute cash received from PVR to its unitholders, including us, is limited by a number of factors, including:

- PVG's estimated general and administrative expenses as well as other operating expenses;
- expenses of PVR's general partner and PVR;
- reserves necessary for PVG to make the necessary capital contributions to maintain its indirect 2% general partner interest in PVR, as required by PVR's partnership agreement upon the issuance of additional limited partner securities by PVR;
- reserves PVG's general partner believes prudent for PVG to maintain the proper conduct of its business or to provide for future distributions by PVG; and
- restrictions on distributions contained in any future debt agreements.

PVR may issue additional limited partner interests or other equity securities, which may increase the risk that PVR will not have sufficient available cash to maintain or increase its cash distribution level, which in turn may reduce the available cash that PVG has to distribute to its unitholders, including us.

PVR has wide latitude to issue additional limited partner interests on the terms and conditions established by its general partner. PVG receives cash distributions from PVR on the general partner interest, IDRs and the limited partner interest that PVG holds. Because a majority of the cash PVG receives from PVR is attributable to PVG's indirect ownership of the IDRs, payment of distributions on additional PVR limited partner interests may increase the risk that PVR will be unable to maintain or increase its quarterly cash distribution per unit, which in turn may reduce the amount of incentive distributions PVG receives and the available cash that PVG has to distribute to its unitholders, including us.

Conflicts of interest may arise because the board of directors of the respective general partners of PVG and PVR has a fiduciary duty to manage the general partners in a manner that is beneficial to their owners, and at the same time, in a manner that is beneficial to the respective unitholders of PVG and PVR.

We own the sole general partner of PVG and PVG owns the sole general partner of PVR. PVG and PVR are publicly traded limited partnerships. Each of the board of directors of the general partners owes a fiduciary duty to the respective unitholders of PVG and PVR, and not just to us and PVG as owners of the general partners. As a result of these conflicts, the board of directors of the general partners of PVG and PVR may favor the interests of the public unitholders of PVG and PVR over the interests of the respective owners of the general partners.

Congress is considering proposed legislation that may, if enacted, negatively impact the value of our limited partner interests in PVG by precluding PVG from qualifying for treatment as a partnership for U.S. federal income tax purposes under the publicly traded partnership rules.

In response to recent public offerings of interests in the management operations of private equity funds and hedge funds, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code and changing the characterization of certain types of income received from partnerships. In particular, one proposal recharacterizes certain income and gain received with respect to "investment service partnership interests" as ordinary income for the performance of services, which may not be treated as qualifying income for publicly traded partnerships. As such proposal is currently interpreted, a significant portion of PVG's interests in PVR may be viewed as an investment service partnership interest. Although we are unable to predict whether the proposed legislation, or any other proposals, will ultimately be enacted, the enactment of any such legislation could negatively impact the value of our limited partner interests in PVG.

Risks Related to PVR's Coal and Natural Resource Management Business

If PVR's lessees do not manage their operations well or experience financial difficulties, their production volumes and PVR's coal royalties revenues could decrease.

PVR depends on its lessees to effectively manage their operations on its properties. PVR's lessees make their own business decisions with respect to their operations, including decisions relating to:

- the method of mining;
- credit review of their customers;
- marketing of the coal mined;
- coal transportation arrangements;
- negotiations with unions;
- employee hiring and firing;
- employee wages, benefits and other compensation;
- permitting;
- surety bonding; and
- mine closure and reclamation.

If PVR's lessees do not manage their operations well, or if they experience financial difficulties, their production could be reduced, which would result in lower coal royalties revenues to PVR and could have a material adverse effect on PVR's business, results of operations or financial condition.

The coal mining operations of PVR's lessees are subject to numerous operational risks that could result in lower coal royalties revenues.

PVR's coal royalties revenues are largely dependent on the level of production from its coal reserves achieved by its lessees. The level of PVR's lessees' production is subject to operating conditions or events that may increase PVR's lessees' cost of mining and delay or halt production at particular mines for varying lengths of time and that are beyond their or its control, including:

- the inability to acquire necessary permits;
- changes or variations in geologic conditions, such as the thickness of the coal deposits and the amount of rock embedded in or overlying the coal deposit;
- changes in governmental regulation of the coal industry;
- mining and processing equipment failures and unexpected maintenance problems;
- adverse claims to title or existing defects of title;
- interruptions due to power outages;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions;
- employee injuries or fatalities; and
- fires and explosions.

Any interruptions to the production of coal from PVR's reserves could reduce its coal royalties revenues and could have a material adverse effect on PVR's business, results of operations or financial condition. In addition, PVR's coal royalties revenues are based upon sales of coal by its lessees to their customers. If PVR's lessees do not receive payments for delivered coal on a timely basis from their customers, their cash flow would be adversely affected, which could cause PVR's cash flow to be adversely affected and could have a material adverse effect on PVR's business, results of operations or financial condition.

A substantial or extended decline in coal prices could reduce PVR's coal royalties revenues and the value of PVR's coal reserves.

A substantial or extended decline in coal prices from recent levels could have a material adverse effect on PVR's lessees' operations (including mine closures) and on the quantities of coal that may be economically produced from its properties. In addition, because a majority of PVR's coal royalties are derived from coal mined on PVR's properties under leases containing royalty rates based on the higher of a fixed base price or a percentage of the gross sales price, PVR's coal royalties revenues could be reduced by such a decline. Such a decline could also reduce PVR's coal services revenues and the value of its coal reserves. Additionally, volatility in coal prices could make it difficult to estimate with precision the value of PVR's coal reserves and any coal reserves that PVR may consider for acquisition. The future state of the global economy, including financial and credit markets on coal production levels and prices is uncertain. Depending on the longevity and ultimate severity of the downturn, demand for coal may decline, which could adversely effect production and pricing for coal mined by PVR's lessees, and, consequently, adversely affect the royalty income received by PVR.

PVR depends on a limited number of primary operators for a significant portion of its coal royalties revenues and the loss of or reduction in production from any of PVR's major lessees would reduce its coal royalties revenues.

PVR depends on a limited number of primary operators for a significant portion of its coal royalties revenues. In the year ended December 31, 2009, five primary operators, each with multiple leases, accounted for 61% of PVR's coal royalties revenues and 10% of our total consolidated revenues. If any of these operators enters bankruptcy or decides to cease operations or significantly reduces its production, PVR's coal royalties revenues would be reduced.

A failure on the part of PVR's lessees to make coal royalty payments could give PVR the right to terminate the lease, repossess the property or obtain liquidation damages and/or enforce payment obligations under the lease. If PVR repossessed any of its properties, PVR would seek to find a replacement lessee. PVR may not be able to find a replacement lessee and, if it finds a replacement lessee, PVR may not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If PVR enters into a new lease, the replacement operator might not achieve the same levels of production or sell coal at the same price as the lessee it replaced. In addition, it may be difficult for PVR to secure new or replacement lessees for small or isolated coal reserves, since industry trends toward consolidation favor larger-scale, higher technology mining operations to increase productivity rates.

PVR's coal business will be adversely affected if PVR is unable to replace or increase its coal reserves through acquisitions.

Because PVR's reserves decline as its lessees mine its coal, PVR's future success and growth depends, in part, upon its ability to acquire additional coal reserves that are economically recoverable. The current state of the global economy, including financial markets, and the consequential adverse effect on credit availability is adversely impacting PVR's access to new capital and credit availability. Depending on the longevity and ultimate severity of this downturn, PVR's ability to make acquisitions may be significantly adversely affected. If PVR is unable to negotiate purchase contracts to replace or increase its coal reserves on acceptable terms, PVR's coal royalties revenues will decline as its coal reserves are depleted and PVR could, therefore, experience a material adverse effect on its business, results of operations or financial condition. If PVR is able to acquire additional coal reserves, there is a possibility that any acquisition could be dilutive to earnings and reduce its ability to make distributions to unitholders, including us, or to pay interest on, or the principal of, its debt obligations. Any debt PVR incurs to finance an acquisition may similarly affect its ability to make distributions to unitholders, including us, or to pay interest on, or the principal of, its debt obligations. PVR's ability to make acquisitions in the future also could be limited by restrictions under its existing or future debt agreements, competition from other coal companies for attractive properties or the lack of suitable acquisition candidates.

PVR's lessees could satisfy obligations to their customers with coal from properties other than PVR's, depriving PVR of the ability to receive amounts in excess of the minimum coal royalties payments.

PVR does not control its lessees' business operations. PVR's lessees' customer supply contracts do not generally require its lessees to satisfy their obligations to their customers with coal mined from PVR's reserves. Several factors may influence a lessee's decision to supply its customers with coal mined from properties PVR does not own or lease, including the royalty rates under the lessee's lease with PVR, mining conditions, transportation costs and availability and customer coal quality specifications. If a lessee satisfies its obligations to its customers with coal from properties PVR does not own or lease, production under its lease will decrease, and PVR will receive lower coal royalties revenues.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of coal mined from PVR's properties.

Transportation costs represent a significant portion of the total cost of coal for the customers of PVR's lessees. Increases in transportation costs could make coal a less competitive source of energy or could make coal produced by some or all of PVR's lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for PVR's lessees from coal producers in other parts of the country or increased imports from offshore producers.

PVR's lessees depend upon rail, barge, trucking, overland conveyor and other systems to deliver coal to their customers. Disruption of these transportation services due to weather-related problems, strikes, lockouts, bottlenecks, mechanical failures and other events could temporarily impair the ability of PVR's lessees to supply coal to their customers. PVR's lessees' transportation providers may face difficulties in the future and impair the ability of its lessees to supply coal to their customers, thereby resulting in decreased coal royalties revenues to PVR.

PVR's lessees' workforces could become increasingly unionized in the future, which could adversely affect their productivity and thereby reduce PVR's coal royalties revenues.

One of PVR's lessees has one mine operated by unionized employees. This mine was PVR's third largest mine on the basis of coal production for the year ended December 31, 2009. All of PVR's lessees could become increasingly unionized in the future. If some or all of PVR's lessees' non-unionized operations were to become unionized, it could adversely affect their productivity and increase the risk of work stoppages. In addition, PVR's lessees' operations may be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against its lessees' operations. Any further unionization of PVR's lessees' employees could adversely affect the stability of production from its coal reserves and reduce its coal royalties revenues.

PVR's coal reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of PVR's coal reserves.

PVR's estimates of its coal reserves may vary substantially from the actual amounts of coal its lessees may be able to economically recover. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond PVR's control. Estimates of coal reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data;
- the amount of ultimately recoverable coal in the ground;
- the effects of regulation by governmental agencies; and
- future coal prices, operating costs, capital expenditures, severance and excise taxes and development and reclamation costs.

Actual production, revenues and expenditures with respect to PVR's coal reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on the coal reserve data provided by PVR.

Any change in fuel consumption patterns by electric power generators away from the use of coal could affect the ability of PVR's lessees to sell the coal they produce and thereby reduce PVR's coal royalties revenues.

According to the U.S. Department of Energy, domestic electric power generation accounted for approximately 89% of domestic coal consumption in 2008. The amount of coal consumed for domestic electric power generation is affected primarily by the overall demand for electricity, the price and availability of competing fuels for power plants such as nuclear, natural gas, fuel oil and hydroelectric power and environmental and other governmental regulations. PVR believes that most new power plants will be built to produce electricity during peak periods of demand. Many of these new power plants will likely be fired by natural gas because of lower construction costs compared to coal-fired plants and because natural gas is a cleaner burning fuel. The increasingly stringent requirements of the CAA may result in more electric power generators shifting from coal to natural gas-fired power plants. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment — Air Emissions."

Extensive environmental laws and regulations affecting electric power generators could have corresponding effects on the ability of PVR's lessees to sell the coal they produce and thereby reduce PVR's coal royalties revenues.

Federal, state and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury and other compounds emitted into the air from electric power plants, which are the ultimate consumers of the coal PVR's lessees produce. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations may require further emission reductions and associated emission control expenditures. As a result of these current and proposed laws, regulations and trends, electricity generators may elect to switch to other fuels that generate less of these emissions, possibly further reducing demand for the coal that PVR's lessees produce and thereby reducing its coal royalties revenues. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment — Air Emissions."

Concerns about the environmental impacts of fossil-fuel emissions, including perceived impacts on global climate change, are resulting in increased regulation of emissions of greenhouse gases in many jurisdictions and increased interest in and the likelihood of further regulation, which could significantly affect PVR's coal royalties revenues.

Global climate change continues to attract considerable public and scientific attention. Several widely publicized scientific reports have engendered widespread concern about the impacts of human activity, especially fossil fuel combustion, on global climate change. Legislative attention in the United States is being paid to global climate change and to reducing greenhouse gas emissions, particularly from coal combustion by power plants. Such legislation was introduced in Congress in the last several years to reduce greenhouse gas emissions in the United States and further proposals or amendments are likely to be offered in the future. In anticipation of EPA's endangerment finding regarding greenhouse gas emissions (which was finalized in December 2009), the agency proposed two sets of rules regarding possible future regulation of greenhouse gas emissions under the CAA. While the first proposes to regulate greenhouse gas emissions from motor vehicles, the other targets greenhouse gas emissions from large stationary sources such as power plants or industrial facilities. Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired power plants. See Item 1, "Business — Governmental Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment — Air Emissions." Enactment of laws, passage of regulations regarding greenhouse gas emissions by the United States or some of its states, or other actions to limit carbon dioxide emissions could result in electric generators switching from coal to other fuel sources. This may adversely affect the use of and demand for fossil fuels, particularly coal.

Delays in PVR's lessees obtaining mining permits and approvals, or the inability to obtain required permits and approvals, could have an adverse effect on PVR's coal royalties revenues.

Mine operators, including PVR's lessees, must obtain numerous permits and approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. The public has the right to comment on many permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required by PVR's lessees to conduct operations may not be issued, maintained or renewed, may not be issued or renewed in a timely fashion, or may involve requirements that restrict PVR's lessees' ability to economically conduct their mining operations. Limitations on PVR's lessees' ability to conduct their mining operations due to the inability to obtain or renew necessary permits, or due to uncertainty, litigation or delays associated with the eventual issuance of these permits, could have an adverse effect on its coal royalties revenues. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment — Mining Permits and Approvals."

Uncertainty over the precise parameters of the CWA's regulatory scope and a recent federal district court decision may adversely impact PVR's coal lessees' ability to secure the necessary permits for their valley fill surface mining activities.

To dispose of mining overburden generated from surface mining activities, PVR's lessees often need to obtain government approvals, including CWA Section 404 permits to construct valley fills and sediment control ponds. Ongoing uncertainty over which waters are subject to the CWA may adversely impact PVR's lessees' ability to secure these necessary permits. In addition, a 2007 decision by a U.S. District Court in West Virginia invalidated a permit issued to one of PVR's lessees for the Republic No. 2 Mine and enjoined PVR's lessee, Alex Energy, Inc., from taking any further actions under this permit. This ruling was appealed and the appellate court reversed and vacated the district court's order. It is unclear if this ruling will be appealed or if the permits will be challenged on other grounds. Uncertainty over the correct legal standard for issuing Section 404 permits may lead to rulings invalidating other permits, additional challenges to various permits and additional delays and costs in applying for and obtaining new permits that could ultimately have an adverse effect on PVR's coal royalties revenues. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment — Clean Water Act," for more information about the litigation described above

PVR's lessees' mining operations are subject to extensive and costly laws and regulations, which could increase operating costs and limit its lessees' ability to produce coal, which could have an adverse effect on PVR's coal royalties revenues.

PVR's lessees are subject to numerous and detailed federal, state and local laws and regulations affecting coal mining operations, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air quality standards, water pollution, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge of materials into the environment, surface subsidence from underground mining and the effects that mining has on groundwater quality and availability. Numerous governmental permits and approvals are required for mining operations. PVR's lessees are required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed exploration for or production of coal may have upon the environment. The costs, liabilities and requirements associated with these regulations may be significant and time-consuming and may delay commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations (or judicial interpretations of existing laws and regulations) may be adopted in the future that could materially affect PVR's lessees' mining operations, either through direct impacts such as new requirements impacting its lessees' existing mining operations, or indirect impacts such as new laws and regulations that discourage or limit coal consumers' use of coal. Any of these direct or indirect impacts could have an adverse effect on PVR's coal royalties revenues. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Coal and Natural Resource Management Segment."

Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual in the industry and, notwithstanding compliance efforts, PVR does not believe violations by its lessees can be eliminated completely. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens and, to a lesser extent, the issuance of injunctions to limit or cease operations. PVR's lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If PVR's lessees are required to pay these costs and liabilities and if their financial viability is affected by doing so, then their mining operations and, as a result, PVR's coal royalties revenues and its ability to make distributions to us, could be adversely affected.

Risks Related to PVR's Natural Gas Midstream Business

The success of PVR's natural gas midstream business depends upon its ability to find and contract for new sources of natural gas supply.

In order to maintain or increase system throughput levels on PVR's gathering systems and asset utilization rates at its processing plants, PVR must contract for new natural gas supplies. The primary factors affecting PVR's ability to connect new supplies of natural gas to its gathering systems include the level of drilling activity creating new gas supply near its gathering systems, PVR's success in contracting for existing natural gas supplies that are not committed to other systems and PVR's ability to expand and increase the capacity of its systems. PVR may not be able to obtain additional contracts for natural gas supplies.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. PVR has no control over the level of drilling activity in its areas of operations, the amount of reserves underlying the wells and the rate at which production from a well will decline. In addition, PVR has no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital.

PVR's natural gas midstream assets, including its gathering systems and processing plants, are connected to natural gas reserves and wells for which the production will naturally decline over time. PVR's cash flows associated with these systems will decline unless it is able to secure new supplies of natural gas by connecting additional production to these systems. A material decrease in natural gas production in PVR's areas of operation, as a result of depressed commodity prices or otherwise, would result in a decline in the volume of natural gas PVR handles, which would reduce its revenues and operating income. In addition, PVR's future growth will depend, in part, upon whether it can contract for additional supplies at a greater rate than the rate of natural decline in PVR's currently connected supplies.

PVR typically does not obtain independent evaluations of natural gas reserves dedicated to its gathering systems; therefore, volumes of natural gas on PVR's systems in the future could be less than it anticipates.

PVR typically does not obtain independent evaluations of natural gas reserves connected to its gathering systems due to the unwillingness of producers to provide reserve information, as well as the cost of such evaluations. Accordingly, PVR does not have independent estimates of total reserves dedicated to its gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to PVR's gathering systems is less than it anticipates and PVR's is unable to secure additional sources of natural gas, then the volumes of natural gas gathered on PVR's gathering systems in the future could be less than PVR anticipates. A decline in the volumes of natural gas on PVR's systems could have a material adverse effect on PVR's business, results of operations or financial condition.

A reduction in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect PVR's business, results of operations and financial condition.

The NGL products PVR produces, including ethane, propane, normal butane, isobutane and natural gasoline, have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general economic conditions, new government regulations, reduced demand by consumers for products made with NGL products, increased competition from petroleum-based products due to pricing differences, mild winter weather or other reasons, could result in a decline in the volume of NGL products PVR handles or reduce the fees PVR charges for its services. Any reduced demand for PVR's NGL products could adversely affect demand for the services PVR provides as well as NGL prices, which would negatively impact PVR's results of operations and financial condition.

The profitability of PVR's natural gas midstream business is dependent upon prices and market demand for natural gas and NGLs, which are beyond PVR's control and have been volatile.

PVR is subject to significant risks due to fluctuations in natural gas commodity prices. During 2009, PVR generated a majority of its gross margin from two types of contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and NGLs — gas purchase/keep-whole and percentage-of-proceeds arrangements. See Item 1, "Business — Contracts — PVR Natural Gas Midstream Segment."

Virtually all of the system throughput volumes in PVR's Crescent System and Hamlin System are processed under percentage-of-proceeds arrangements. The system throughput volumes in PVR's Panhandle System are processed primarily under either percentage-of proceeds or gas purchase/keep-whole arrangements. Under both types of arrangements, PVR provides gathering and processing services for natural gas received. Under percentage-of-proceeds arrangements, PVR generally sells the NGLs produced from the processing operations and the remaining residue gas at market prices and remits to the producers an agreed upon percentage of the proceeds based on either an index price or the price actually received for gas and NGLs. Under these arrangements, revenues and gross margins decline when natural gas prices and NGL prices decrease. Accordingly, a decrease in the price of natural gas or NGLs could have a material adverse effect on PVR's business, results of operations or financial condition. Under gas purchase/keep-whole arrangements, PVR generally buys natural gas from producers based upon an index price and then sells the NGLs and the remaining residue gas to third parties at market prices. Because the extraction of the NGLs from the natural gas during processing reduces the volume of natural gas available for sale, profitability is dependent on the value of those NGLs being higher than the value of the volume of gas reduction or "shrink." Under these arrangements, revenues and gross margins decrease when the price of natural gas increases relative to the price of NGLs. Accordingly, a change in the relationship between the price of natural gas and the price of NGLs could have a material adverse effect on PVR's business, results of operations or financial condition.

In the past, the prices of natural gas and NGLs have been extremely volatile, and PVR expects this volatility to continue. The markets and prices for residue gas and NGLs depend upon factors beyond PVR's control. These factors include demand for oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions, and other factors, including:

- the state of the global economy, including financial and credit markets, on worldwide demand for oil and domestic demand for natural gas and NGLs;
- the impact of weather on the demand for oil and natural gas
- the level of domestic oil and natural gas production;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Acquisitions and expansions may affect PVR's business by substantially increasing the level of its indebtedness and contingent liabilities and increasing the risks of being unable to effectively integrate these new operations.

From time to time, PVR evaluates and acquires assets and businesses that it believes complement its existing operations. Readily available access to debt and equity capital and credit availability has been and continues to be critical factors in PVR's ability to grow. The current state of the global economy, including financial markets, and the consequential adverse effect on credit availability is adversely impacting PVR's access to new capital and credit availability. Depending on the longevity and ultimate severity of this downturn, PVR's ability to make acquisitions may be significantly adversely affected. In the event PVR completes acquisitions, PVR may encounter difficulties integrating these acquisitions with its existing businesses without a loss of employees or customers, a loss of revenues, an increase in operating or other costs or other difficulties. In addition, PVR may not be able to realize the operating efficiencies, competitive advantages, cost savings or other benefits expected from these acquisitions. Future acquisitions might not generate increases in PVR's cash distributions to its unitholders, and because of the capital used to complete such acquisitions, or the debt incurred, PVR's and our results of operations may change significantly.

Expanding PVR's natural gas midstream business by constructing new gathering systems, pipelines and processing facilities subjects PVR to construction risks.

One of the ways PVR may grow its natural gas midstream business is through the construction of additions to existing gathering, compression and processing systems. The construction of a new gathering system or pipeline, the expansion of an existing pipeline through the addition of new pipe or compression and the construction of new processing facilities involve numerous regulatory, environmental, political and legal uncertainties beyond PVR's control and require the expenditure of significant amounts of capital. PVR's access to such capital is currently adversely impacted by the state of the global economy, including financial and credit markets. If PVR does undertake these projects, they may not be completed on schedule, or at all, or at the anticipated cost. Moreover, PVR's revenues may not increase immediately upon the expenditure of funds on a particular project. For example, the construction of gathering facilities requires the expenditure of significant amounts of capital, which may exceed PVR's estimates. Generally, PVR may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, PVR may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. As a result, there is the risk that new facilities may not be able to attract enough natural gas to achieve PVR's expected investment return, which could have a material adverse effect on PVR's business, results of operations or financial condition.

If PVR is unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then PVR may be unable to fully execute its growth strategy and its cash flows could be reduced.

The construction of additions to PVR's existing gathering assets may require PVR to obtain new rights-of-way before constructing new pipelines. PVR may be unable to obtain rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for PVR to obtain new rights-of-way or to renew existing rights-of-way. If the cost of obtaining new rights-of-way or renewing existing rights-of-way increases, then PVR's cash flows could be reduced.

PVR is exposed to the credit risk of its natural gas midstream customers, and nonpayment or nonperformance by PVR's customers would reduce its cash flows.

PVR is subject to risk of loss resulting from nonpayment or nonperformance by its natural gas midstream customers. PVR depends on a limited number of customers for a significant portion of its natural gas midstream revenues. In the year ended December 31, 2009, 21% of PVR's natural gas midstream segment revenues and 13% of our total consolidated revenues related to two of PVR's natural gas midstream segment customers. Any nonpayment or nonperformance by PVR's natural gas midstream segment customers would reduce its cash flows.

Any reduction in the capacity of, or the allocations to, PVR in interconnecting third-party pipelines could cause a reduction of volumes processed, which could adversely affect PVR's revenues and cash flows.

PVR is dependent upon connections to third-party pipelines to receive and deliver residue gas and NGLs. Any reduction of capacities of these interconnecting pipelines due to testing, line repair, reduced operating pressures or other causes could result in reduced volumes gathered and processed in PVR's natural gas midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, PVR's allocations in these pipelines could be reduced. Any reduction in volumes gathered and processed in PVR's facilities could adversely affect its revenues and cash flows.

Natural gas derivative transactions may limit PVR's potential gains and involve other risks.

In order to manage PVR's exposure to price risks in the marketing of its natural gas and NGLs, PVR periodically enters into condensate, natural gas and NGL price hedging arrangements with respect to a portion of its expected production. PVR's hedges are limited in duration, usually for periods of two years or less. However, in connection with acquisitions, sometimes PVR's hedges are for longer periods. These hedging transactions may limit PVR's potential gains if natural gas or NGL prices were to rise (or decline with respect to natural gas hedges entered into to lock the frac spread) over the price established by the hedging arrangements. Moreover, PVR has entered into derivative transactions related to only a portion of its condensate, natural gas and NGL volumes. As a result, PVR will continue to have direct commodity price risk with respect to the unhedged portion of these volumes. In trying to maintain an appropriate balance, PVR may end up hedging too much or too little, depending upon how natural gas or NGL prices fluctuate in the future.

In addition, derivative transactions may expose PVR to the risk of financial loss in certain circumstances, including instances in which:

- PVR's production is less than expected;
- there is a widening of price basis differentials between delivery points for PVR's production and the delivery point assumed in the hedge arrangement;
- the counterparties to PVR's futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts natural gas or NGL prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

The accounting standards regarding hedge accounting are complex, and even when PVR engages in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our Consolidated Financial Statements may reflect volatility due to these derivatives, even when there is no underlying economic impact at that point. In addition, it is not always possible for PVR to engage in a derivative transaction that completely mitigates its exposure to commodity prices. Our Consolidated Financial Statements may reflect a gain or loss arising from an exposure to commodity prices for which PVR is unable to enter into a completely effective hedge transaction.

PVR's natural gas midstream business involves many hazards and operational risks, some of which may not be fully covered by insurance.

PVR's natural gas midstream operations are subject to the many hazards inherent in the gathering, compression, treating, processing and transportation of natural gas and NGLs, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of PVR's related operations. PVR's natural gas midstream operations are concentrated in Texas and Oklahoma, and a natural disaster or other hazard affecting these areas could have a material adverse effect on its business, results of operations or financial condition. PVR is not fully insured against all risks incident to its natural gas midstream business. PVR does not have property insurance on all of its underground pipeline systems that would cover damage to the pipelines. PVR is not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect PVR's business, results of operations or financial condition.

Federal, state or local regulatory measures could adversely affect PVR's natural gas midstream business.

PVR owns and operates an 11-mile interstate natural gas pipeline that, pursuant to the NGA, is subject to the jurisdiction of the FERC. The FERC has granted PVR waivers of various requirements otherwise applicable to conventional FERC-jurisdictional pipelines, including the obligation to file a tariff governing rates, terms and conditions of open access transportation service. The FERC has determined that PVR will have to comply with the filing requirements if the PVR natural gas midstream segment ever desires to apply for blanket transportation authority to transport third-party gas on the 11-mile pipeline. The FERC may revoke these waivers at any time.

PVR's natural gas gathering facilities generally are exempt from the FERC's jurisdiction under the NGA, but the FERC regulation nevertheless could change and significantly affect PVR's gathering business and the market for its services. For a more detailed discussion of how regulatory measures affect PVR's natural gas gathering business, see Item 1, "Business — Government Regulation and Environmental Matters — PVR Natural Gas Midstream Segment."

Failure to comply with applicable federal and state laws and regulations can result in the imposition of administrative, civil and criminal remedies.

The PVR natural gas midstream business is subject to extensive environmental regulation.

Many of the operations and activities of PVR's gathering systems, plants and other facilities are subject to significant federal, state and local environmental laws and regulations. These include, for example, laws and regulations that impose obligations related to air emissions and discharge of wastes from PVR's facilities and the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by PVR or the prior owners of its natural gas midstream business or locations to which it or they have sent wastes for disposal. These laws and regulations can restrict or impact PVR's business activities in many ways, including restricting the manner in which it disposes of substances, requiring pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in PVR's natural gas midstream business due to its handling of natural gas and other petroleum products, air emissions related to its natural gas midstream operations, historical industry operations, waste disposal practices and the use by the prior owners of its natural gas midstream business of natural gas flow meters containing mercury. For example, an accidental release from one of PVR's pipelines or processing facilities could subject it to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase PVR's compliance costs and the cost of any remediation that may become necessary. PVR may incur material environmental costs and liabilities. Insurance may not provide sufficient coverage in the event an environmental claim is made. See Item 1, "Business — Government Regulation and Environmental Matters — PVR Natural Gas Midstream Segment."

The PVR natural gas midstream segment may record impairment losses on its long-lived assets.

The PVR natural gas midstream segment has completed a number of acquisitions in recent years, including the North Texas System (Lone Star Gathering, L.P., or Lone Star). See Note 5 to the Consolidated Financial Statements for a description of the PVR natural gas midstream segment's material acquisitions. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed, which involved the use of various assumptions. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Unforeseen changes in operations, the business environment or market conditions could substantially alter management's assumptions and could result in lower estimates of values of acquired assets or of future cash flows. This could result in impairment charges being recorded in our Consolidated Statements of Income.

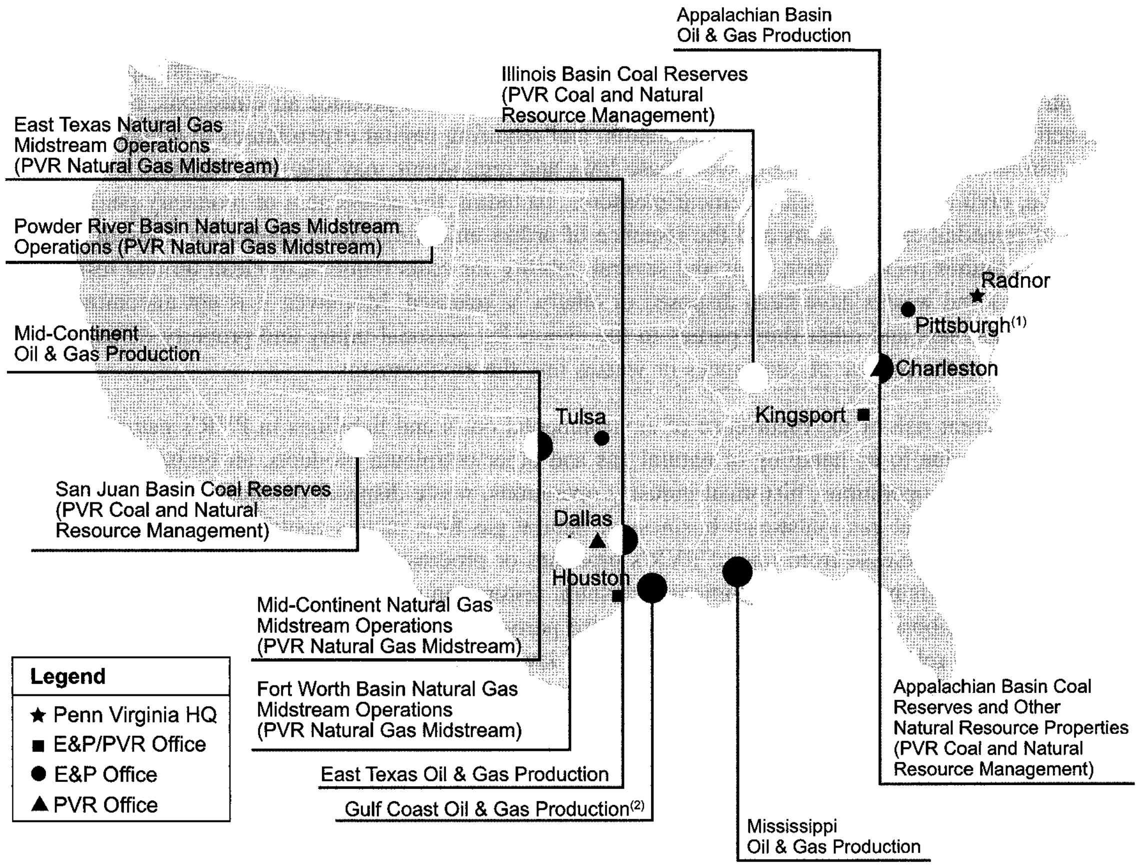
Item 1B Unresolved Staff Comments

We have received no written SEC staff comments regarding our periodic or current reports under the Exchange Act which were issued 180 days or more preceding the end of our 2009 fiscal year that remain unresolved.

Item 2 Properties

Title to Properties

The following map shows the general locations of our oil and gas production and exploration, PVR's coal reserves and related infrastructure investments and PVR's natural gas gathering and processing systems as of December 31, 2009:



(1) We opened a Pittsburgh, PA office in the first half of 2010.

(2) We sold our Gulf Coast oil and gas production assets in January 2010.

We believe that we have satisfactory title to all of our properties and the associated oil, natural gas and coal reserves in accordance with standards generally accepted in the oil and natural gas, coal and natural resource management and natural gas midstream industries.

Facilities

We are headquartered in Radnor, Pennsylvania, with additional offices in Pittsburgh, Pennsylvania, Oklahoma, Tennessee, Texas and West Virginia. All of our office facilities are leased, except for PVR's West Virginia office, which it owns. We believe that our properties are adequate for our current needs.

Oil and Gas Segment Properties

As is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and to undeveloped oil and gas leases upon execution of any contracts. Prior to the commencement of drilling operations, a thorough title examination is conducted and curative work is performed with respect to significant defects. To the extent title opinions or other investigations reflect defects, we cure such title defects. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Prior to completing an acquisition of producing oil and gas assets, we obtain or review title opinions on all material leases. Our oil and gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties.

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2009, 2008 and 2007. The proved reserve estimates presented below were prepared by Wright & Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited) in the Notes to the Consolidated Financial Statements and the report of Wright & Company Inc., which is included as an Exhibit to this annual report. We did not file any reports during the year ended December 31, 2009 with any federal authority or agency with respect to our estimate of oil and gas reserves.

	Natural Gas	Oil and Condensate	Natural Gas Equivalents	Standardized Measure(1)	Price Measurement Used(2)	
	(Bcf)	(MMBbl)	(Bcfe)	$ in millions	$/MMBtu	$/Bbl
2009						
Developed	388	8.4	439	$425		
Undeveloped	389	18.0	496	100		
	777	26.4	935	$525	$3.87	$61.18
2008						
Developed	411	9.9	470	$692		
Undeveloped	343	17.1	446	37		
	754	27.0	916	$729	$5.71	$44.60
2007						
Developed	373	4.5	399	$788		
Undeveloped	215	10.7	281	184		
	588	15.2	680	$972	$6.80	$95.95

(1) Standardized measure is the present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes and estimated future costs. The standardized measure considers average prices for the year ended December 31, 2009 and prices in effect at year-end for the years ended December 31, 2008 and 2007, respectively.

(2) Natural gas and oil prices were based on average (beginning of month basis) sales prices per Mcf and Bbl with the representative price of natural gas adjusted for basis premium and BTU content to arrive at the appropriate net price.

Effective for 2009 and future periods and in accordance with the SEC's new guidelines, the engineers' estimates of future net revenues from our properties and the standardized measure thereof are based on the average (beginning of month basis) oil and natural gas sales prices in effect during 2009, and estimated future costs as of December 31, 2009. The prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. As noted in the table above, the standardized measure for periods prior to 2009 was based on prices in effect at December 31. Prices for oil and gas are subject to substantial seasonal fluctuations as well as fluctuations resulting from numerous other factors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves expected to be recovered through new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. The proved undeveloped reserves included in our current estimates relate to wells that are forecasted to be drilled within the next five years. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Therefore, the standardized measure amounts shown above should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. The information set forth in the foregoing tables includes revisions of certain volumetric reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in production prices.

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Our Manager of Engineering is primarily responsible for overseeing the preparation of the Company's reserve estimate by our independent third party engineers, Wright & Company, Inc. The Manager of Engineering has over twenty-four years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The technical person primarily responsible for review of our reserve estimates at Wright & Company, Inc., meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

For additional information about the risks inherent in our estimates of proved reserves, see "Risk Factors" in Item 1A.

Production and Reserves by Region

The following tables set forth by region the estimated quantities of proved reserves, as well as the average daily production and total production for the periods presented:

	As of December 31, 2009		
Region	**Proved Reserves**	**% of Total Proved Reserves**	**% Proved Developed**
	(Bcfe)		
Appalachia	134	14%	79%
Mississippi	175	19%	57%
East Texas	403	43%	31%
Mid-Continent	199	21%	37%
Gulf Coast[1]	24	3%	92%
	935	100%	

Region	Average Daily Production for the Year Ended December 31, 2009	2008	2007	Total Production for the Year Ended December 31, 2009	2008	2007
		(MMcfe)			(MMcfe)	
Appalachia	31.4	31.4	34.0	11,465	11,497	12,424
Mississippi	21.5	20.1	20.7	7,822	7,340	7,551
East Texas	35.9	36.6	21.9	13,117	13,409	7,986
Mid-Continent	35.1	20.9	11.3	12,825	7,646	4,131
Gulf Coast[1]	15.8	19.1	23.2	5,771	6,989	8,477
	139.7	128.1	111.1	51,000	46,881	40,569

(1) We completed the sale of our Gulf Coast properties in a transaction that closed on January 29, 2010.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2009. The acreage is located primarily in the Appalachian, Mississippi, East Texas, Mid-Continent and Gulf Coast regions of the United States.

	Gross Acreage	Net Acreage
	(in thousands)	
Developed	865	752
Undeveloped	761	393
	1,626	1,145

Wells Drilled

The following table sets forth the gross and net numbers of exploratory and development wells that we drilled during the years ended December 31, 2009, 2008 and 2007. The number of wells drilled refers to the number of wells reaching total depth at any time during the respective year. Net wells equal the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells which were producing oil or gas or which were capable of commercial production.

	2009 Gross	2009 Net	2008 Gross	2008 Net	2007 Gross	2007 Net
Development						
Productive	25	16.9	259	160.5	265	198.5
Non-productive	1	1.0	4	3.0	6	5.1
Under evaluation	4	1.8	11	8.8	—	—
Total development	30	19.7	274	172.3	271	203.6
Exploratory						
Productive	2	1.0	6	3.5	11	5.2
Non-productive	—	—	5	2.8	3	1.6
Under evaluation	—	—	1	1.0	4	2.6
Total exploratory	2	1.0	12	7.3	18	9.4
Total	32	20.7	286	179.6	289	213.0

The four development wells under evaluation at December 31, 2009 included three in the Mid-Continent region (Granite Wash) and one Lower Bossier (Haynesville) Shale well in East Texas.

The exploratory well under evaluation as of December 31, 2008 was in the Mid-Continent region. In 2009, the well was determined to be commercially viable and we reclassified $2.5 million of suspended exploratory drilling costs related to this well to proved property and equipment.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we had a working interest at December 31, 2009.

Operated Wells		Non-Operated Wells		Total Wells	
Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
1,667	1,482.1	460	91.4	2,127	1,573.5

In addition to the above working interest wells, we own royalty interests in 2,818 gross wells.

Coal Reserves and Other Natural Resource Management Assets

As of December 31, 2009, PVR owned or controlled approximately 829 million tons of proven and probable coal reserves located on approximately 497,000 acres (including fee and leased acreage) in Illinois, Kentucky, New Mexico, Virginia and West Virginia. PVR's coal reserves are in various surface and underground mine seams located on the following properties:

- *Central Appalachia Basin*: properties located in eastern Kentucky, southwestern Virginia and southern West Virginia;
- *Northern Appalachia Basin*: properties located in northern West Virginia;
- *Illinois Basin*: properties located in southern Illinois and western Kentucky; and
- *San Juan Basin*: properties located in the four corners area of New Mexico.

Coal reserves are coal tons that can be economically extracted or produced at the time of determination considering legal, economic and technical limitations. All of the estimates of PVR's coal reserves are classified as proven and probable reserves. Proven and probable coal reserves are defined as follows:

Proven Coal Reserves. Proven coal reserves are reserves for which: (i) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; (ii) grade and/or quality are computed from the results of detailed sampling; and (iii) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that the size, shape, depth and mineral content of reserves are well-established.

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

In areas where geologic conditions indicate potential inconsistencies related to coal reserves, PVR performs additional exploration to ensure the continuity and mineability of the coal reserves. Consequently, sampling in those areas involves drill holes or channel samples that are spaced closer together than those distances cited above.

Coal reserve estimates are adjusted annually for production, unmineable areas, acquisitions and sales of coal in place. The majority of PVR's coal reserves are high in energy content, low in sulfur and suitable for either the steam or to a lesser extent metallurgical market.

The amount of coal that a lessee can profitably mine at any given time is subject to several factors and may be substantially different from "proven and probable coal reserves." Included among the factors that influence profitability are the existing market price, coal quality and operating costs.

The following tables set forth reserve information as of December 31, 2009 with respect to each of PVR's properties (tons in millions):

	Proven and Probable Reserves as of December 31, 2009					
Property	**Underground**	**Surface**	**Total**	**Steam**	**Metallurgical**	**Total**
Central Appalachia	443.6	160.3	603.9	514.7	89.2	603.9
Northern Appalachia	23.4	—	23.4	23.4	—	23.4
Illinois Basin	154.2	9.7	163.9	163.9	—	163.9
San Juan Basin	—	37.4	37.4	37.4	—	37.4
Total	621.2	207.4	828.6	739.4	89.2	828.6

The following table sets forth the coal reserves PVR owned and leased with respect to each of its coal properties as of December 31, 2009 (tons in millions):

Property	**Owned**	**Leased**	**Total Controlled**
Central Appalachia	452.9	151.0	603.9
Northern Appalachia	23.4	—	23.4
Illinois Basin	133.9	30.0	163.9
San Juan Basin	33.6	3.8	37.4
Total	643.8	184.8	828.6

The following table sets forth PVR's coal reserve activity for the periods presented and ended (tons in millions):

	As of December 31,		
	2009	**2008**	**2007**
Reserves at beginning of year	826.8	818.4	765.4
Purchase of coal reserves	2.4	34.6	60.0
Tons mined by lessees	(34.3)	(33.7)	(32.5)
Revisions of estimates and other	33.7	7.5	25.5
Reserves at end of year	828.6	826.8	818.4

Coal Preparation and Loading Facilities

PVR generates coal services revenues from fees it charges to its lessees for the use of its coal preparation and loading facilities, which are located in Virginia, West Virginia and Kentucky. The facilities provide efficient methods to enhance lessee production levels and exploit PVR's reserves.

Timber and Oil and Gas Royalty Interests

PVR owns approximately 243,000 acres of forestland in Kentucky, Virginia and West Virginia. The majority of PVR's forestland is located on properties that also contain its coal reserves.

PVR owns royalty interests in approximately 7.2 Bcfe of proved oil and gas reserves located in Kentucky, Virginia and West Virginia. Approximately 86% of PVR's oil and gas royalty interests in these reserves are associated with the leases of property in eastern Kentucky and southwestern Virginia that PVR acquired from us in 2007.

Natural Gas Midstream Systems

PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR owns, leases or has rights-of-way to the properties where the majority of its natural gas midstream facilities are located. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

PVR owned six natural gas processing facilities having 400 MMcfd of total capacity as of December 31, 2009. PVR's natural gas midstream operations currently include four natural gas gathering and processing systems and two stand-alone natural gas gathering systems, including: (i) the Panhandle gathering and processing facilities in the Texas/Oklahoma panhandle area; (ii) the Crossroads gathering and processing facilities in East Texas; (iii) the Crescent gathering and processing facilities in central Oklahoma; (iv) the Arkoma gathering system in eastern Oklahoma; (v) the North Texas gathering and pipeline facilities in the Fort Worth Basin; and (vi) the Hamlin gathering and processing facilities in west-central Texas. These assets included approximately 4,118 miles of natural gas gathering pipelines as of December 31, 2009. In addition, PVR owns a 25% member interest in Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin.

The following table sets forth information regarding PVR's natural gas midstream assets:

Asset	Type	Approximate Length (Miles)	Current Processing Capacity (MMcfd)
Panhandle System[1]	Gathering pipelines and processing facilities	1,681	260
Crossroads System	Gathering pipelines and processing facility	8	80
Crescent System	Gathering pipelines and processing facility	1,701	40
Hamlin System	Gathering pipelines and processing facility	516	20
Arkoma System	Gathering pipelines	78	—
North Texas Gathering System	Gathering pipelines	134	—
		4,118	400

(1) Includes the Beaver, Spearman and Sweetwater natural gas processing plants.

Item 3 Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Item 1, "Business — Government Regulation and Environmental Matters," for a more detailed discussion of our material environmental obligations.

Item 4 Reserved

Part II

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

Market Information

Our common stock is traded on the NYSE under the symbol "PVA." The high and low sales prices (composite transactions) and dividends declared related to each fiscal quarter in 2009 and 2008 were as follows:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2009	$26.32	$17.25	$0.05625
September 30, 2009	$23.92	$13.16	$0.05625
June 30, 2009	$23.24	$10.46	$0.05625
March 31, 2009	$31.53	$ 7.22	$0.05625
December 31, 2008	$53.19	$21.65	$0.05625
September 30, 2008	$81.00	$45.74	$0.05625
June 30, 2008	$76.44	$44.07	$0.05625
March 31, 2008	$46.12	$37.01	$0.05625

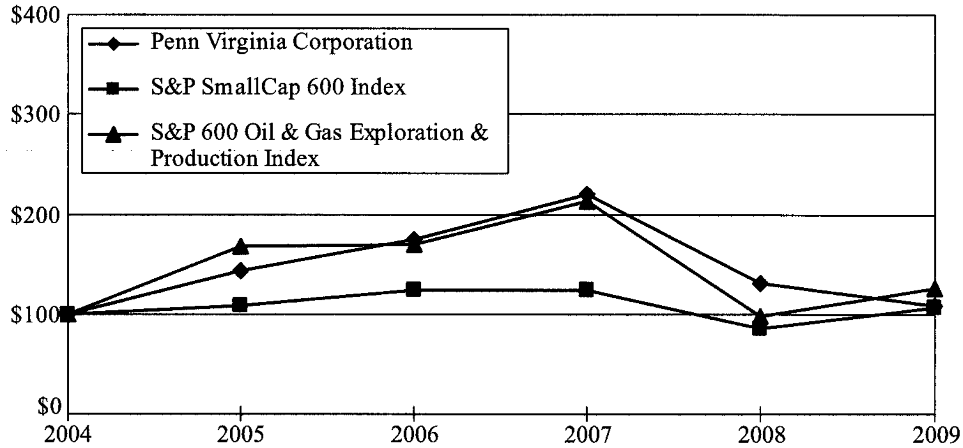
Equity Holders

As of February 8, 2010, there were 485 record holders and approximately 3,000 beneficial owners (held in street name) of our common stock.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration & Production Index and the Standard & Poor's Small Cap 600 Index. There are six companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Penn Virginia Corporation, Petroleum Development Corporation, Petroquest Energy Inc., St. Mary Land & Exploration Company, Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2005 in us and each index at December 31, 2004 closing prices.

COMPARISON OF CUMULATIVE FIVE-YEAR TOTAL RETURN



	2005	2006	2007	2008	2009
Penn Virginia Corporation	$142.77	$175.31	$219.67	$131.45	$109.13
S&P Small Cap 600 Index	$107.68	$123.96	$123.59	$ 85.19	$106.97
S&P 600 Oil & Gas Exploration & Production Index	$167.38	$168.90	$213.89	$ 98.66	$125.69

Item 6 Selected Financial Data

The following selected historical financial information was derived from our Consolidated Financial Statements as of December 31, 2009, 2008, 2007, 2006 and 2005, and for each of the years then ended. The selected financial data should be read in conjunction with our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data."

	2009	2008	2007	2006	2005[1]
	(In thousands, except per share amounts)				
Statement of Income Data:					
Revenues	$ 815,137	$1,220,851	$ 852,950	$ 753,929	$ 673,864
Depreciation, depletion and amortization	$ 223,367	$ 192,236	$ 129,523	$ 94,217	$ 76,937
Operating income (loss)[2]	$ (98,202)	$ 256,823	$ 192,624	$ 170,532	$ 162,017
Net income (loss)[3]	$ (77,368)	$ 181,520	$ 80,810	$ 118,927	$ 92,477
Income (loss) attributable to Penn Virginia Corporation[3]	$ (114,643)	$ 121,084	$ 50,491	$ 75,909	$ 62,088
Common Stock Data:					
Earnings (loss) per common share, basic[4]	$ (2.62)	$ 2.89	$ 1.32	$ 2.03	$ 1.67
Earnings (loss) per common share, diluted[4]	$ (2.62)	$ 2.87	$ 1.31	$ 2.01	$ 1.66
Weighted-average shares outstanding:					
Basic	43,811	41,760	38,061	37,362	37,092
Diluted	43,811	42,031	38,358	37,732	37,464
Actual shares outstanding at year-end	45,272	41,786	41,331	37,490	37,201
Dividends declared per share	$ 0.225	$ 0.225	$ 0.225	$ 0.225	$ 0.225
Market value at year-end	$ 21.29	$ 25.66	$ 42.89	$ 34.23	$ 27.87
Number of shareholders	3,486	8,761	8,196	7,970	7,095
Balance Sheet and Other Financial Data:					
Property and equipment, net[3]	$2,352,358	$2,512,177	$1,899,067	$1,358,383	$ 983,219
Total assets[3]	$2,888,507	$2,996,565	$2,252,271	$1,633,149	$1,251,546
Total debt[3]	$1,118,527	$1,107,538	$ 727,369	$ 439,046	$ 333,954
Shareholders' equity[3]	$1,237,999	$1,222,442	$ 911,700	$ 815,848	$ 618,883
Cash provided by operating activities	$ 275,947	$ 383,774	$ 313,030	$ 275,819	$ 231,407
Cash acquisitions and additions	$ 286,353	$ 879,086	$ 713,510	$ 464,939	$ 475,324
Other Statistical Data:					
Total production (MMcfe)	51,000	46,881	40,569	31,260	27,362
Proved reserves (Bcfe)	935	916	680	487	377

(1) The 2005 column includes the results of operations of the PVR natural gas midstream segment since March 3, 2005, the closing date of the acquisition of Cantera Gas Resources, LLC.

(2) Operating income (loss) in 2009, 2008, 2007, 2006 and 2005 included impairment charges of $106.4 million, $20.0 million, $2.6 million, $8.5 million and $4.8 million related to our oil and gas properties and other assets. Operating income in 2008 included a loss on the impairment of goodwill of $31.8 million

(3) Certain financial data for 2008 and 2007 has been adjusted in connection with a change in accounting principle with respect to our Convertible Notes (see Note 22 to the Consolidated Financial Statements).

(4) For comparative purposes, amounts per common share in 2006 and 2005 have been adjusted for the effect of a two-for-one stock split on June 19, 2007.

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

The following discussion and analysis of the financial condition and results of operations of Penn Virginia Corporation and its subsidiaries ("Penn Virginia," "we," "us" or "our") should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8. All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated.

Overview of Business

We are an independent oil and gas company primarily engaged in the development, exploration and production of natural gas and oil in various domestic onshore regions including East Texas, the Mid-Continent, Appalachia and Mississippi. We also indirectly own partner interests in PVR, which is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR are held principally through our general partner interest and our 51.4% limited partner interest in PVG. As of December 31, 2009, PVG owned an approximately 37% limited partner interest in PVR and 100% of the general partner of PVR, which holds a 2% general partner interest in PVR and all of the IDRs. Although results are consolidated for financial reporting, Penn Virginia, PVG and PVR operate with independent capital structures. As such, cash flow available to us from PVG and PVR is only in the form of cash distributions declared and paid to us as a result of our partner interests in those entities.

We are engaged in three primary business segments: (i) oil and gas, (ii) coal and natural resource management and (iii) natural gas midstream. We operate our oil and gas segment, and PVR operates the coal and natural resource management and natural gas midstream segments.

Key Developments

During 2009, the following general business developments and corporate actions had an impact upon the financial reporting of our results of operations and financial position as well as the overall presentation of financial information: (i) the effect of 2009 commodity prices on our drilling program, (ii) disposition of Gulf Coast properties, which was completed in January 2010, (iii) entrance into a new credit facility and the issuance of senior notes, (iv) sale of 10 million PVG units, (v) common stock offering of 3.5 million shares, (vi) organization restructuring and (vii) implementation of an accounting standard update with respect to our 4.5% Convertible Senior Subordinated Notes, or Convertible Notes. A discussion of these key developments follows:

2009 Commodity Prices and Impact on Drilling Program

Beginning in the latter part of 2008 and continuing into 2009, the domestic energy markets experienced a precipitous decline in commodity prices including those for natural gas, crude oil and NGLs, among others. Accordingly, these conditions led to our decision at the beginning of 2009 to significantly reduce our drilling program. In addition to the significant impact on revenues directly attributable to lower commodity prices, we incurred certain material costs associated with the suspension of our drilling program. The effect on revenues and a more thorough analysis of delayed drilling costs is provided in Results of Operations — Oil and Gas Segment below. Energy markets and related commodity prices improved in the second half of 2009, providing support for our decision to significantly increase the expected size of our drilling program in 2010 as compared to 2009.

Disposition of Gulf Coast Properties

In December 2009, we signed agreements to complete the sale of our Gulf Coast properties in exchange for $32 million of net cash proceeds and certain oil and gas properties in the Selma Chalk play in our Mississippi region, excluding transaction costs and purchase and sale adjustments. The transaction closed on January 29, 2010. During 2009, we recorded total asset impairments of $97.4 million in connection with the classification of these properties as held for sale. Additional information is provided in Notes 5 and 19 to the Consolidated Financial Statements.

Completion of a New Credit Facility and the Issuance of Senior Notes

In November 2009, we entered into the Revolver, which is a new credit agreement that provides for a $300 million revolving credit facility commitment against a $420 million borrowing base, and includes a $20 million sublimit for the issuance of letters of credit as well as an option to increase the commitments under the Revolver by up to an additional $225 million. The credit facility is secured by our reserves. The initial borrowing base of $420 million was subsequently reduced to $380 million in connection with the Gulf Coast property sale discussed above.

In June 2009, we issued $300 million of 10.375% Senior Unsecured Notes, or Senior Notes, which will mature on June 15, 2016. The Senior Notes were sold at 97% of par and provided proceeds of $281.6 million, net of original issue discount and issuance costs.

Additional information regarding the Revolver and the Senior Notes is provided in the discussion of Liquidity and Capital Resources that follows as well as Note 12 to the Consolidated Financial Statements.

Sale of PVG Units

In September 2009, we sold 10 million units of PVG owned by us for proceeds net of offering expenses of $118.1 million resulting in a reduction of our limited partner interest in PVG from 77.0% to 51.4%. Additional information is provided in the Liquidity and Capital Resources discussion that follows as well as Note 17 to the Consolidated Financial Statements.

Common Stock Offering of 3.5 Million Shares

In May 2009, we completed the sale of 3.5 million shares of our common stock in a registered public offering that provided $64.8 million of net proceeds. Additional information is provided in the Liquidity and Capital Resources discussion that follows as well as Note 17 to the Consolidated Financial Statements.

Organization Restructuring

In November 2009, we implemented an organization restructuring that will result in the transfer of certain corporate and oil and gas accounting and administrative functions from our Kingsport, Tennessee office location to our Houston, Texas and Radnor, Pennsylvania locations. In addition, the restructuring will result in the relocation of our eastern region oil and gas divisional office from Kingsport to a new office in Pittsburgh, Pennsylvania. Approximately 30 employees will be terminated in connection with the restructuring plans and we anticipate incurring approximately $4 million in costs including termination benefits, relocation costs and other incremental costs associated with expanding our other office locations. Additional information is provided in Note 20 to the Consolidated Financial Statements.

Retrospective Application of Change in Accounting Principle for Convertible Notes

Effective January 1, 2009, we adopted a new accounting standard regarding convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement with respect to our Convertible Notes. The change in accounting principle, as applied retrospectively to all periods presented, resulted in adjustments to the Consolidated Statements of Income and Cash Flows for the years ended December 31, 2007 and 2008, respectively, as well as the Consolidated Balance Sheet as of December 31, 2008. Additional information is provided in Note 22 to the Consolidated Financial Statements.

Liquidity and Capital Resources

Cash Flows

Although results are consolidated for financial reporting, Penn Virginia, PVG and PVR operate with independent capital structures. With the exception of cash distributions paid to us by PVG and PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, asset sales, credit facility borrowings and the issuance of common stock and new PVG and PVR units. We expect that our cash needs and the cash needs of PVG and PVR will continue to be met independently of each other with a combination of these funding sources.

With respect to Penn Virginia (excluding the sources and uses of capital by PVG and PVR), we satisfy our working capital requirements and fund our capital expenditures using cash generated from our operations, asset sales, borrowings under the Revolver and proceeds from common stock offerings. We satisfy our debt service obligations and dividend payments solely using cash generated from our operations. We believe that the cash generated from our operations and our borrowing capacity will be sufficient to meet our 2010 working capital requirements, anticipated capital expenditures (other than major capital improvements or acquisitions), scheduled debt payments and dividend payments. Our ability to satisfy our obligations and planned expenditures will depend on our future operating performance, which will be affected by, among other things, prevailing economic conditions in the commodity markets of oil and natural gas, some of which are beyond our control.

PVR's ability to satisfy its obligations and planned expenditures will depend upon its future operating performance, which will be affected by prevailing economic conditions in the coal industry and natural gas midstream market, some of which are beyond PVR's control.

The following tables summarize our statements of cash flows, on a disaggregated basis, for the periods presented:

For the Year Ended December 31, 2009	Oil & Gas, PVA Corporate & Other	PVG/PVR	Consolidated
Cash flows from operating activities	$ 117,733	$ 158,214	$ 275,947
Cash flows from investing activities			
Acquisitions	(17,314)	(29,580)	(46,894)
Additions to property and equipment	(188,362)	(51,097)	(239,459)
Other	15,094	1,147	16,241
Net cash used in investing activities	(190,582)	(79,530)	(270,112)
Cash flows from financing activities			
Dividends paid	(9,836)	—	(9,836)
Distributions received (paid)	42,279	(120,450)	(78,171)
Debt borrowings (repayments)	(332,000)	52,000	(280,000)
Short-term bank borrowings (repayments)	(7,542)	—	(7,542)
Net proceeds from issuance of senior notes	291,009	—	291,009
Net proceeds from issuance of common stock	64,835	—	64,835
Net proceeds from the sale of PVG units	118,080	—	118,080
Debt issuance costs paid	(14,959)	(9,258)	(24,217)
Net cash provided by financing activities	151,866	(77,708)	74,158
Net increase in cash and cash equivalents	$ 79,017	$ 976	$ 79,993

For the Year Ended December 31, 2008	Oil & Gas, PVA Corporate & Other	PVG/PVR	Consolidated
Cash flows from operating activities	$ 246,587	$ 137,187	$ 383,774
Cash flows from investing activities			
Acquisitions	(33,371)	(260,376)	(293,747)
Additions to property and equipment	(513,687)	(71,652)	(585,339)
Other	32,521	998	33,519
Net cash used in investing activities	(514,537)	(331,030)	(845,567)
Cash flows from financing activities			
Dividends paid	(9,398)	—	(9,398)
Distributions received (paid)	44,018	(108,263)	(64,245)
Debt borrowings (repayments)	210,000	156,000	366,000
Short-term bank borrowings	7,542	—	7,542
Net proceeds from issuance of PVR units	—	138,141	138,141
Other, net	11,764	(4,200)	7,564
Net cash provided by financing activities	263,926	181,678	445,604
Net decrease in cash and cash equivalents	$ (4,024)	$ (12,165)	$ (16,189)

Cash Flows From Operating Activities

Consistent with the oil and gas segment's operating performance, our cash flows from operating activities reflected significant declines in commodity prices for our products partially offset by lower cash operating expenses and severance taxes as well as lower working capital utilization primarily attributable to a significantly reduced drilling program. Also, mitigating the decline in cash revenues during 2009 was the net cash received from our derivatives portfolio. Our derivatives provided approximately $58 million in cash receipts during 2009 as compared to net cash payments of approximately $8 million during 2008.

Excluding the impact of derivatives settlements, PVG's cash flows from operating activities declined by approximately $20 million during 2009 as compared to 2008 consistent with a decline in the PVR natural gas midstream segment's gross margin despite higher system throughput. In addition, the PVR natural gas midstream segment incurred higher cash operating expenses primarily attributable to operating a more expanded network during 2009 resulting from acquisitions and other expansions in recent prior years. Also contributing to lower net cash flows from operating activities was a decline in the PVR coal and natural resource management segment's revenues partially offset by a proportionate decline in cash operating expenses. With respect to derivatives, PVR received approximately $3 million in cash receipts during 2009 as compared to net cash payments of approximately $38 million during 2008.

Cash Flows From Investing Activities

The cash used by both us and PVR in investing activities were primarily for capital expenditures partially offset by proceeds received from the sale of certain properties and equipment. Consistent with economic conditions during 2009, we significantly reduced our drilling program and PVR reduced its capital additions and acquisition activities.

Our 2008 expenditures were primarily discretionary in nature and included development drilling and various lease acquisitions largely in East Texas. PVR's expenditures consisted primarily of discretionary capital expenditures which included PVR's 25% member interest acquisition in Thunder Creek, the Lone Star acquisition, pipeline assets in the Anadarko Basin of Oklahoma and Texas, expansion capital expenditures related to the Spearman and Crossroads plants and the acquisition of approximately 29 million tons of coal reserves and an estimated 56 MMbf of hardwood timber in western Virginia and eastern Kentucky.

The following table sets forth our capital expenditures programs, by segment, for the periods presented:

	Year Ended December 31,	
	2009	**2008**
Oil and gas:		
Development drilling	$140,243	$ 481,401
Exploration drilling	2,524	23,785
Seismic	1,195	4,169
Lease acquisition and other	18,456	95,529
Pipeline and gathering facilities	9,382	36,812
	171,800	641,696
Coal and natural resources:		
Acquisitions	2,067	27,075
Other property and equipment expenditures	185	195
	2,252	27,270
Natural gas midstream:		
Acquisitions	27,514	259,417
Expansion capital expenditures	36,863	59,385
Other property and equipment expenditures	8,399	14,505
	72,776	333,307
Other	1,958	1,336
Total capital expenditures	$248,786	$1,003,609

The following table reconciles the total capital expenditures programs provided above with the net cash paid for acquisitions and additions to property and equipment as reflected in the Consolidated Statements of Cash Flows for the periods presented:

	Year Ended December 31,	
	2009	2008
Total capital expenditures	$248,786	$1,003,609
Less:		
Exploration expenses		
Seismic	(1,195)	(4,169)
Other	(3,460)	(2,419)
Changes in accrued capitalized costs	39,549	(33,181)
Non-cash purchase consideration(1)	—	(87,865)
Add:		
Capitalized interest paid	2,544	2,712
Other	129	399
Total capital expenditure cash outflows	$286,353	$ 879,086
Cash paid for acquisitions	$ 46,894	$ 293,747
Cash paid for additions to property and equipment	239,459	585,339
Total reflected in cash flows from investing activities	$286,353	$ 879,086

(1) Attributable to the PVR natural gas midstream segment's 2008 Lone Star acquisition and reflects the following items: PVR units valued at $15.2 million; PVG units, which were purchased from two of our subsidiaries, valued at $68 million and a $5 million guaranteed payment accrued in 2008 and paid in 2009 (see Note 5 to the Consolidated Financial Statements).

Cash Flows From Financing Activities

During 2009, we issued the Senior Notes which provided proceeds of $281.6 million, net of an original issue discount and issuance costs and sold 3.5 million shares of our common stock in a registered public offering providing net proceeds of $64.8 million. In addition, we sold 10 million units of PVG owned by us for net proceeds of $118.1 million resulting in a reduction of our limited partner interest in PVG from 77.0% to 51.4%. These proceeds were used primarily to eliminate our borrowings under the Revolver. During 2008, we had net borrowings of $210 million under the Revolver

During 2009, PVR had net borrowings of $60.0 million under its revolving credit agreement, or PVR Revolver, which was primarily used to fund PVR's capital expenditures program. In connection with the Revolver, the increase in the capacity of the PVR Revolver and the issuance of our Senior Notes, a total of $24.2 million was paid in 2009 in issuance costs and fees.

During 2008, PVR had net borrowings of $156 million primarily attributable to the PVR Revolver offset by the repayment of PVR's Senior Unsecured Notes due 2013. PVR also received net proceeds of $141.1 million from the sale of its common units in a registered public offering in 2008, which was comprised of net proceeds of $138.2 million from the sale of the common units to the public and $2.9 million in contributions from its general partner to maintain its 2% general partner interest in PVR. These increases were partially offset by increased cash distributions paid to PVR's and PVG's partner's due to increases in the distributions paid per unit as well as the increase in PVR's outstanding common units resulting from the 2008 unit offering.

In January 2010, PVG declared a $0.38 ($1.52 on an annualized basis) per unit quarterly distribution for the three months ended December 31, 2009. This distribution was paid on February 19, 2010 to unitholders of record at the close of business on February 2, 2010. In January 2010, PVR declared a $0.47 ($1.88 on an annualized basis) per unit quarterly distribution for the three months ended December 31, 2009. This distribution was paid on February 12, 2010 to unitholders of record at the close of business on February 2,

2010. The portion of PVR's distribution paid to PVG serves as the basis for PVG's distribution to its unitholders, including us. On a combined basis, we received a total of $7.7 million of distributions from PVG and PVR in February 2010.

Sources of Liquidity

Debt and Credit Facilities

	As of December 31,	
	2009	2008
Short-term borrowings	$ —	$ 7,542
Revolving credit facility	—	332,000
Senior notes	291,749	—
Convertible notes	206,678	199,896
Total recourse debt of the Company	498,427	539,438
Long-term debt of PVR	620,100	568,100
Total consolidated debt	1,118,527	1,107,538
Less: Short-term borrowings	—	(7,542)
Total consolidated long-term debt	$1,118,527	$1,099,996

Revolving Credit Facility. In November 2009, we entered into the Revolver and simultaneously terminated our previous credit agreement. The Revolver provides for a $300 million revolving credit facility and matures in November 2012. We have the option to increase the commitments under the Revolver by up to an additional $225 million upon the receipt of commitments from one or more lenders. The Revolver is governed by a borrowing base calculation and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The initial borrowing base was $420 million and was reduced to $380 million in connection with the sale of our Gulf Coast properties as discussed previously. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions and includes a $20 million sublimit for the issuance of letters of credit.

Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from the London Interbank Offered Rate ("LIBOR"), as adjusted for statutory reserve requirements for Eurocurrency liabilities (the "Adjusted LIBOR"), plus an applicable margin ranging from 2.000% to 3.000% or (ii) the greater of (a) the prime rate, (b) federal funds effective rate plus 0.5% and (c) the one-month Adjusted LIBOR plus 1.0%, in each case, plus an applicable margin (ranging from 1.000% to 2.000%). In each case, the applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity.

The Revolver is guaranteed by Penn Virginia and all of our material oil and gas subsidiaries. The obligations under the Revolver are secured by a first priority lien on a portion of our proved oil and gas reserves and a pledge of the equity interests in the guarantor subsidiaries, which excludes PVG, PVR and their subsidiaries.

As of December 31, 2009, there were no amounts outstanding under the Revolver and we had remaining borrowing capacity of up to $299.3 million, net of outstanding letters of credit of $0.7 million. A discussion of the applicable covenants and related compliance with respect to the Revolver is provided in the discussion of Financial Condition that follows.

Senior Notes. In June 2009, we issued and sold $300 million of Senior Notes which mature in June 2016. The Senior Notes were sold at 97% of par, equating to an effective yield to maturity of approximately 11%. The net proceeds from the sale of the Senior Notes of $281.6 million were used to repay borrowings under the revolving credit facility associated with the previous credit agreement. The Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our subsidiaries that guarantee our indebtedness under the Revolver.

Convertible Notes. In December 2007, we issued the Convertible Notes with interest payable semiannually in arrears on May 15 and November 15 of each year. The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment, and, if not converted or repurchased earlier, will mature in November 2012.

The Convertible Notes are unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes will rank senior in right of payment to any of our future junior subordinated indebtedness and will structurally rank junior to all existing and future indebtedness of our guarantor subsidiaries.

In connection with the sale of the Convertible Notes, we entered into convertible note hedge transactions, or the Note Hedges, with respect to shares of our common stock with affiliates of certain of the underwriters of the Convertible Notes (collectively, the "Option Counterparties"). The Note Hedges cover, subject to anti-dilution adjustments, the net shares of our common stock that would be deliverable to converting noteholders in the event of a conversion of the Convertible Notes.

We also entered into separate warrant transactions, or the Warrants, whereby we sold to the Option Counterparties warrants to acquire, subject to anti-dilution adjustments, approximately 3,982,680 shares of our common stock at an exercise price of $74.25 per share. Upon exercise of the Warrants, we will deliver shares of our common stock equal to the difference between the then market price and the strike price of the Warrants.

If the market value per share of our common stock at the time of conversion of the Convertible Notes is above the strike price of the Note Hedges, the Note Hedges entitle us to receive from the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount) based on the excess of the then current market price of our common stock over the strike price of the Note Hedges. Additionally, if the market price of our common stock at the time of exercise of the Warrants exceeds the strike price of the Warrants, we will owe the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount), not offset by the Note Hedges, in an amount based on the excess of the then current market price of our common stock over the strike price of the Warrants.

On October 3, 2008, one of the Option Counterparties, Lehman Brothers OTC Derivatives Inc., or Lehman OTC, joined other Lehman Brothers entities and filed for bankruptcy protection. We had purchased 22.5% of the Note Hedges from Lehman OTC, or the Lehman Note Hedges, for approximately $8.3 million, and we had sold 22.5% of the Warrants to Lehman OTC for approximately $4.1 million. If the Lehman Note Hedges are rejected or terminated in connection with the Lehman OTC bankruptcy, we would have a claim against Lehman OTC and possibly Lehman Brothers Inc., as guarantor, for the damages and/or close-out values resulting from any such rejection or termination. While we intend to pursue any claim for damages and/or close-out values resulting from the rejection or termination of the Lehman Note Hedges, at this point in the Lehman bankruptcy cases it is not possible to determine with accuracy the ultimate recovery, if any, that we may realize on potential claims against Lehman OTC or its affiliated guarantor resulting from any rejection or termination of the Lehman Note Hedges. We also do not know whether Lehman OTC will assume or reject the Lehman Note Hedges, and therefore cannot predict whether Lehman OTC intends to perform its obligations under the Lehman Note Hedges. If Lehman OTC does not perform such obligations and the price of our common stock exceeds the $57.75 conversion price (as adjusted) of the Convertible Notes, our existing shareholders would experience dilution at the time or times the Convertible Notes are converted. The extent of any such dilution would depend, among other things, on the then prevailing market price of our common stock and the number of shares of common stock then outstanding, but we believe the impact will not be material and will not affect our income statement presentation. We are not otherwise exposed to counterparty risk related to the bankruptcies of Lehman Brothers Inc. or its affiliates and do not believe that the Lehman bankruptcies will have a material adverse effect on our financial condition or results of operations.

Interest Rate Swaps. In December 2009, we entered into an a new interest rate swap agreement, or New Interest Rate Swap, to establish variable rates on a portion of the outstanding obligation under the Senior Notes. The notional amount of the New Interest Rate Swap is $100 million, or approximately one-third of the face amount outstanding under the Senior Notes. We will pay a variable rate equivalent to the three-month LIBOR plus a margin of 8.175%, and the counterparties will pay a fixed rate of 10.375%. The term of the New Interest Rate Swap extends through June 2013.

In addition to the New Interest Rate Swap, we previously entered into interest rate swaps agreements, or the Previous Interest Rate Swaps, to establish fixed rates on a portion of the previously outstanding borrowings under the Revolver until December 2010. The notional amounts of the Previous Interest Rate Swaps total $50 million. We pay a weighted-average fixed rate of 5.34% on the notional amount, and the counterparties pay a variable rate equal to the three-month LIBOR. As there are currently no amounts outstanding under the Revolver, we entered into an offsetting fixed-to-floating interest rate swap in December 2009 that effectively unwinds the Previous Interest Rate Swaps. With respect to this fixed-to-floating interest rate swap, we pay a variable rate equivalent to the three-month LIBOR and the counterparties will pay a fixed rate of 0.53% until December 2010.

Long-Term Debt of PVR. As of December 31, 2009, the long-term debt of PVR was solely attributable to the PVR Revolver. In March 2009, PVR increased the size of the PVR Revolver from $700 million to $800 million. The PVR Revolver is secured with substantially all of PVR's assets. As of December 31, 2009, PVR had remaining borrowing capacity of $178.3 million on the PVR Revolver, net of outstanding borrowings of $620.1 million and letters of credit of $1.6 million. The PVR Revolver matures in December 2011 and is available to PVR for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10.0 million sublimit for the issuance of letters of credit. Interest is payable at a base rate plus an applicable margin of up to 1.25% if PVR selects the base rate borrowing option or at a rate derived from LIBOR plus an applicable margin ranging from 1.75% to 2.75% if PVR selects the LIBOR-based borrowing option. At December 31, 2009, the base rate applicable margin was 0.75% and the LIBOR-based rate applicable margin was 2.25%. The weighted average interest rate on borrowings outstanding under the PVR Revolver during 2009 was approximately 2.7%. Debt outstanding under the PVR Revolver is non-recourse to us and PVG. A discussion of the applicable covenants and related compliance with respect to the PVR Revolver is provided in the discussion of Financial Condition that follows.

PVR Interest Rate Swaps. PVR entered into interest rate swaps, or the PVR Interest Rate Swaps, to establish fixed rates on a portion of the outstanding borrowings under the PVR Revolver. The following table sets forth the PVR Interest Rate Swap positions as of December 31, 2009:

Dates	**Notional Amounts**	**Weighted-Average Fixed Rate**
	(in millions)	
Until March 2010	$310.0	3.54%
March 2010 – December 2011	$250.0	3.37%
December 2011 – December 2012	$100.0	2.09%

The PVR Interest Rate Swaps extend one year past the maturity of the current PVR Revolver. After considering the applicable margin of 2.25% in effect as of December 31, 2009, the total interest rate on the $310 million portion of PVR Revolver borrowings covered by the PVR Interest Rate Swaps was 5.79% as of December 31, 2009.

Common Stock Offering

In May 2009, we completed the sale of 3.5 million shares of our common stock in a registered public offering. The net sales proceeds of $64.8 million were used to repay borrowings under the Revolver.

Asset Dispositions

During 2009, we initiated a number of asset dispositions in addition to other debt and capital raising activities in connection with a broader effort to support funding for our capital spending program for 2010 (see Future Capital Needs and Commitments discussion that follows). The following table summarizes the net cash realized from the largest asset dispositions that closed during the year ended December 31, 2009:

Asset Description	Net Cash Realized
10 million common units of PVG	$118,080
Mid-Continent oil and gas properties	10,211
Gulf Coast oil and gas properties[(1)]	4,871
	$133,162

(1) Includes $2.3 million received as a deposit in connection the with sale of the Gulf Coast properties that closed on January 29, 2010.

As referenced in the table above, we completed the sale of our remaining Gulf Coast properties in January 2010 which completed our efforts to exit activities in this region. This sale resulted in the realization of additional net proceeds of $23.2 million in January 2010 as well as the receipt of certain oil and gas properties in Mississippi. These Gulf Coast properties were classified as "Assets held for sale" and are reflected as such on the Consolidated Balance Sheets as of December 31, 2009 (see also Notes 5 and 19 to the Consolidated Financial Statements).

Financial Condition

Covenant Compliance

The terms of the Revolver require us to maintain certain financial covenants. These covenants, which are effective with the period ended December 31, 2009, are as follows:

- Total debt to EBITDAX, each as defined in the Revolver, for any four consecutive quarters may not exceed 4.0 to 1.0 reducing to 3.5 to 1.0 for periods ending on or after September 30, 2011. Both total debt and EBITDAX excludes those items of PVG and PVR as they are not guarantor subsidiaries under the Revolver. EBITDAX, which is a non-GAAP (generally accepted accounting principles) measure, generally means net income plus interest expense, taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments, other non-cash charges or losses and the amount of cash distributions received from PVG and PVR.
- The current ratio, as of the last day of any quarter, may not be less than 1.0 to 1.0. The current ratio is generally defined as current assets to current liabilities. For purposes of this ratio, the Revolver essentially excludes the current assets and current liabilities of PVG and PVR as they are not guarantor subsidiaries. Current assets and current liabilities attributable to derivative instruments are also excluded. In addition, current assets include the amount of any unused commitment under the Revolver.

As of December 31, 2009, we were in compliance with all of the Revolver's covenants.

The financial covenants of the PVR Revolver are as follows:

- Total debt to consolidated EBITDA may not exceed 5.25 to 1.0. EBITDA, which is a non-GAAP measure, is generally defined in the PVR Revolver as PVR's net income plus interest expense, net of interest income, depreciation, depletion and amortization expenses, and non-cash hedging activity and impairments.
- Consolidated EBITDA to interest expense may not be less than 2.5 to 1.0.

As of December 31, 2009, PVR was in compliance with all of the PVR Revolver's covenants.

The following table summarizes the actual results of our and PVR's covenant compliance for the period ended December 31, 2009:

Description of Covenant	Covenant	Actual Results
Penn Virginia Corporation and guarantor subsidiaries:		
Total debt to EBITDAX	4.0	1.9
Current ratio	1.0	6.9
PVR:		
Debt to EBITDA	5.25	3.36
EBITDA to interest expense	2.5	7.5

In the event that we or PVR would be in default of our covenants under the Revolver and the PVR Revolver, respectively, we or PVR could appeal to the banks for a waiver of the covenant default. Should the banks deny our or PVR's appeal to waive the covenant default, the outstanding borrowings under the Revolver or the PVR Revolver would become payable on demand and would be reclassified as a component of current liabilities on the Consolidated Balance Sheet. In addition, both the Revolver and the PVR Revolver impose limitations on dividends and distributions, as well as limit the ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our or PVR's business or enter into a merger or sale of our or PVR's assets, including the sale or transfer of interests in our or PVR's subsidiaries.

Future Capital Needs and Commitments

Subject to commodity prices and the availability of capital, we expect to expand our oil and gas operations over the next several years by continuing to execute a program dominated by development drilling and, to a lesser extent, exploration drilling, supplemented periodically with property and reserve acquisitions.

In 2010, we anticipate making oil and gas segment capital expenditures, excluding acquisitions, of up to approximately $425 million. The capital expenditures are expected to be primarily funded from internally generated sources of cash, including cash distributions received from PVG and PVR, supplemented by Revolver borrowings and proceeds from the sale of non-core assets and the sale of part or all of our interests in PVG. At December 31, 2009, we had $79 million of cash and $300 million of unused borrowing capacity under the Revolver. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on industry conditions, cash flows provided by operating activities and the availability of capital.

For future periods, we continue to assess funding needs for our growth opportunities in the context of our presently available debt capacity. We expect to continue to use a combination of cash flows from operating activities and debt financing, supplemented with equity issuances and the sale of other non-core assets, potentially including all or part of our interests in PVG, to fund our growth.

PVR believes that its remaining borrowing capacity of $178.3 million will be sufficient for its 2010 capital needs and commitments. PVR's short-term cash requirements for operating expenses and quarterly distributions to PVG, as the owner of PVR's general partner, and unitholders are expected to be funded through operating cash flows. In 2010, PVR anticipates making capital expenditures, excluding acquisitions, of up to $60 million. The majority of these capital expenditures are expected to be incurred in the PVR natural gas midstream segment. PVR intends to fund these capital expenditures with a combination of operating cash flows and borrowings under the PVR Revolver. Long-term cash requirements for acquisitions and other capital expenditures are expected to be funded by operating cash flows, borrowings under the PVR Revolver and the issuances of additional debt and equity securities if available under commercially acceptable terms.

Part of PVR's long-term strategy is to increase cash available for distribution to PVR's unitholders by making acquisitions and other capital expenditures. PVR's ability to make these acquisitions and other capital expenditures in the future will depend largely on the availability of debt financing and on PVR's ability to periodically use equity financing through the issuance of new common units. Future financing will depend on various factors, including prevailing market conditions, interest rates and PVR's financial condition and credit rating.

Contractual Obligations

The following table summarizes our and PVR's contractual obligations as of December 31, 2009:

	Payments Due by Period				
	Total	Less than 1 Year	1 – 3 Years	3 – 5 Years	More Than 5 Years
Senior Notes	$ 291,749	$ —	$ —	$ —	$291,749
Convertible Notes	206,678	—	206,678	—	—
PVR Revolver	620,100	—	620,100	—	—
Interest expense(1)	272,450	56,915	97,544	72,600	45,391
Asset retirement obligations(2)	8,849	—	—	—	8,849
Derivatives(3)	22,892	16,147	6,745	—	—
Rental commitments(4)	40,893	8,452	10,608	8,771	13,062
Oil and gas activities(5)	59,812	23,629	15,714	5,468	15,001
Natural gas midstream activities(6)	32,320	13,103	10,202	7,354	1,661
Total contractual obligations(7)	$1,555,743	$118,246	$967,591	$94,193	$375,713

(1) Represents estimated interest payments that will be due under the Senior Notes, Convertible Notes and PVR Revolver.

(2) The undiscounted balance was approximately $52.5 million as of December 31, 2009.

(3) Represents estimated payments that we and PVR will make resulting from the oil and gas and natural gas midstream commodity derivatives as well as both from our and PVR's interest rate swaps.

(4) Primarily relates to equipment and building leases and leases of coal reserve-based properties which PVR subleases, or intends to sublease, to third parties.

(5) Commitments for oil and gas activities relating to firm transportation agreements and drilling contracts.

(6) Commitments for PVR natural gas midstream activities relating to firm transportation agreements.

(7) Total contractual obligations do not include anticipated 2010 capital expenditures.

Part of the purchase price for the PVR Lone Star acquisition includes contingent payments of approximately $55 million. These contingency payments will be made by PVR if certain revenue targets are met before June 30, 2013. Because the outcome of these contingent payments is not determinable beyond a reasonable doubt, PVR did not accrue these contingent payments as a liability during the year ended December 31, 2009. Rather, once the revenue targets are met, the contingent payments will be recorded as an additional cost of the Lone Star acquisition.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2009, the material off-balance sheet arrangements and transactions that we or PVR have entered into included operating lease arrangements, drilling commitments, firm transportation agreements, and letters of credit, all of which are customary in our and PVR's business. See Contractual Obligations summarized above for more details related to the value of off-balance sheet arrangements. Neither we nor PVR had any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Results of Operations

Consolidated Review

The following table presents summary consolidated operating results for the periods presented:

	Year Ended December 31,		
	2009	2008	2007
Revenues	$ 815,137	$1,220,851	$852,950
Expenses	913,339	964,028	660,326
Operating income (loss)	(98,202)	256,823	192,624
Other income (expense)			
Interest expense	(68,884)	(49,299)	(37,851)
Derivatives	11,854	46,582	(47,282)
Other	2,612	(666)	3,651
Income tax (expense) benefit	75,252	(71,920)	(30,332)
Net income (loss)	(77,368)	181,520	80,810
Less: Net income attributable to noncontrolling interests	(37,275)	(60,436)	(30,319)
Income (loss) attributable to Penn Virginia Corporation	$(114,643)	$ 121,084	$ 50,491

The following tables present summary financial information relating to our segments for the periods presented:

	Oil & Gas	PVR Coal and Natural Resource Management	PVR Natural Gas Midstream	Eliminations and Other	Consolidated
For the Year Ended December 31, 2009:					
Revenues	$ 235,084	$144,600	$512,104	$ (76,651)	$ 815,137
Cost of midstream gas purchased	—	—	406,583	(72,729)	333,854
	235,084	144,600	105,521	(3,922)	481,283
Operating costs and expenses	154,233	24,231	45,842	23,886	248,192
Depreciation, depletion and amortization	150,429	31,330	38,905	2,703	223,367
Impairments	106,415	1,511	—	—	107,926
Operating income (loss)	$(175,993)	$ 87,528	$ 20,774	$ (30,511)	$ (98,202)
For the Year Ended December 31, 2008:					
Revenues	$ 469,330	$153,327	$728,253	$(130,059)	$1,220,851
Cost of midstream gas purchased	—	—	612,530	(127,909)	484,621
	469,330	153,327	115,723	(2,150)	736,230
Operating costs and expenses	146,515	26,226	37,615	25,051	235,407
Depreciation, depletion and amortization	132,276	30,805	27,361	1,794	192,236
Impairments	19,963	—	31,801	—	51,764
Operating income (loss)	$ 170,576	$ 96,296	$ 18,946	$ (28,995)	$ 256,823
For the Year Ended December 31, 2007:					
Revenues	$ 303,241	$111,639	$437,806	$ 264	$ 852,950
Cost of midstream gas purchased	—	—	343,293	—	343,293
	303,241	111,639	94,513	264	509,657
Operating costs and expenses	109,449	20,138	26,777	28,560	184,924
Depreciation, depletion and amortization	87,223	22,690	18,822	788	129,523
Impairments	2,586	—	—	—	2,586
Operating income (loss)	$ 103,983	$ 68,811	$ 48,914	$ (29,084)	$ 192,624

Oil and Gas Segment

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

The following table sets forth a summary of certain financial operating performance and other data for our oil and gas segment for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Revenues				
Natural gas	$ 169,666	$368,801	$(199,135)	(54%)
Crude oil	43,258	46,529	(3,271)	(7%)
NGL	15,735	21,292	(5,557)	(26%)
Total product revenues	228,659	436,622	(207,963)	(48%)
Gain on sale of property and equipment	2,345	30,634	(28,289)	(92%)
Other income	4,080	2,074	2,006	97%
Total revenues	235,084	469,330	(234,246)	(50%)
Expenses				
Operating	55,699	59,459	3,760	6%
Taxes other than income	16,556	23,336	6,780	29%
General and administrative	22,625	21,284	(1,341)	(6%)
Production costs	94,880	104,079	9,199	9%
Exploration	57,754	42,436	(15,318)	(36%)
Depreciation, depletion and amortization	150,429	132,276	(18,153)	(14%)
Impairments	106,415	19,963	(86,452)	(433%)
Loss on sale of assets	1,599	—	(1,599)	n/a
Total expenses	411,077	298,754	(112,323)	(38%)
Operating income (loss)	$(175,993)	$170,576	$(346,569)	(203%)
Production:				
Natural gas (MMcf)	43,338	41,493	1,845	4%
Crude oil (MBbl)	750	506	244	48%
NGL (MBbl)	527	392	135	34%
Total production (MMcfe)	51,000	46,881	4,119	9%
Rates:				
Natural gas ($/Mcf)	$ 3.91	$ 8.89	$ (4.97)	(56%)
Crude oil ($/Bbl)	57.68	91.95	(34.28)	(37%)
NGL ($/Bbl)	29.86	54.32	(24.46)	(45%)
Total ($/Mcfe)	$ 4.48	$ 9.31	$ (4.83)	(52%)

Production

The following tables set forth a summary of our production volume and product revenue by geographical region for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
	(MMcfe)			
East Texas	13,116	13,409	(293)	(2%)
Appalachia	11,465	11,497	(32)	(0%)
Mid-Continent	12,826	7,646	5,180	68%
Mississippi	7,822	7,340	482	7%
Gulf Coast	5,771	6,989	(1,218)	(17%)
Total production	51,000	46,881	4,119	9%

	Year Ended December 31,		Favorable (Unfavorable)	% Change
	2009	2008		
East Texas	$ 55,159	$129,105	$ (73,946)	(57%)
Appalachia	46,863	107,282	(60,419)	(56%)
Mid-Continent	63,720	59,969	3,751	6%
Mississippi	32,792	69,916	(37,124)	(53%)
Gulf Coast	30,125	70,350	(40,225)	(57%)
Total revenues	$228,659	$436,622	$(207,963)	(48%)

Approximately 85% and 89% of total production in the years ended December 31, 2009 and 2008 was natural gas. Total production increased primarily due to continued development of the Granite Wash play in the Mid-Continent region and the horizontal Selma Chalk play in Mississippi. Our Appalachian production was relatively consistent with the prior year. We have deferred drilling in the East Texas region until early 2010 and we were in the process of exiting all of our activities in the Gulf Coast region during the fourth quarter of 2009.

In 2009, we drilled a total of 32 gross (20.7 net) wells, including 30 gross (19.7 net) development wells and 2 gross (1.0 net) exploratory wells. All wells were successful except 5 gross (2.8 net) development wells, including 4 gross (1.8 net) development wells under evaluation at December 31, 2009.

Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects. We recently shifted our focus to the Lower Bossier (Haynesville) Shale play, which we believe has increased proved reserves and production levels. In this East Texas play, we drilled 10 gross (9.5 net) wells, including 8 gross (7.5 net) successful wells. We also have unconventional development programs in the Mid-Continent region where we drilled 17 gross (6.2 net) wells, including 14 gross (5.4 net) successful wells, primarily in the Granite Wash and Woodford Shale plays. In the Selma Chalk play in Mississippi and Appalachian region, we drilled 5 gross (5.0 net) wells all of which were successful.

Revenues

The following table provides an analysis of the change in our oil and gas segment revenues for the year ended December 31, 2009 as compared to the year ended December 31, 2008:

	2009 Revenue Variance Due to		
	Volume	Price	Total
Natural gas	$16,399	$(215,534)	$(199,135)
Crude oil	22,437	(25,708)	(3,271)
NGL	7,333	(12,890)	(5,557)
	$46,168	$(254,131)	$(207,963)

Our revenues, profitability and future rate of growth are highly dependent on the prevailing prices for oil and natural gas, which are affected by numerous factors that are generally beyond our control. Crude oil prices are generally determined by global supply and demand. Natural gas prices are influenced by national and regional supply and demand. A substantial or extended decline in the price of oil or natural gas could have a material adverse effect on our revenues, profitability and cash flow and could, under certain circumstances, result in an impairment of some of our oil and natural gas properties. Our future profitability and growth are also highly dependent on the results of our exploratory and development drilling programs.

Effects of Derivatives

Our natural gas and crude oil revenues may change significantly from period to period as a result of changes in commodity prices or production volumes. As part of our risk management strategy, we use derivative financial instruments to hedge natural gas and, to a lesser extent, oil prices.

For the derivatives related to the oil and gas segment, we received $59.9 million in cash settlements in 2009 and we paid cash settlements of $7.6 million in 2008. The following table reconciles natural gas and crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31, 2009	2008	Favorable (Unfavorable)	% Change
Natural gas revenues as reported	$169,666	$368,801	$(199,135)	(54%)
Cash settlements on natural gas derivatives	55,545	(7,339)	62,884	(857%)
Natural gas revenues adjusted for derivatives	$225,211	$361,462	$(136,251)	(38%)
Natural gas revenue rates per Mcf, as reported	$ 3.91	$ 8.89	$ (4.97)	(56%)
Cash settlements on natural gas derivatives per Mcf	1.29	(0.18)	1.46	(811%)
Natural gas revenue rates per Mcf adjusted for derivatives	$ 5.20	$ 8.71	$ (3.51)	(40%)
Crude oil revenues as reported	$ 43,258	$ 46,529	$ (3,271)	(7%)
Cash settlements on crude oil derivatives	4,361	(281)	4,642	(1652%)
Crude oil revenues adjusted for derivatives	$ 47,619	$ 46,248	$ 1,371	3%
Crude oil revenue rates per Bbl, as reported	$ 57.68	$ 91.95	$ (34.28)	(37%)
Cash settlements on crude oil derivatives per Bbl	5.81	(0.55)	6.37	(1157%)
Crude oil revenue rates per Bbl adjusted for derivatives	$ 63.49	$ 91.40	$ (27.91)	(31%)

Gain on Sale of Property and Equipment

In 2009, we recognized gains on the sale of certain properties and equipment in our East Texas region. In 2008, we recognized gains on the sale of property and equipment, primarily related to the sale of all of our working interest in unproved properties in Louisiana.

Other Income

Other income increased primarily due to increased gathering revenues in the East Texas region resulting from increased production in that region and an overall increase in gathering fees per Mcf that we charged.

Production Costs

The following table sets forth a summary of our production costs per Mcfe for the periods presented:

	Year Ended December 31, 2009	2008	Favorable (Unfavorable)	% Change
Operating	$1.09	$1.27	$0.18	14%
Taxes other than income	0.32	0.50	0.17	35%
General and administrative	0.44	0.45	0.01	2%
Total production costs per Mcfe	$1.86	$2.22	0.36	16%

Operating expenses decreased primarily due to lower repair and maintenance costs and lower water disposal fees partially offset by higher gathering and processing fees from higher production in certain regions. Taxes other than income decreased, primarily due to the timing of refunds and lower severance taxes resulting from lower commodity prices partially offset by the impact of higher production. General and administrative expenses were relatively flat.

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2009	2008	Favorable (Unfavorable)	% Change
Dry hole costs	$ 1,397	$14,435	$ 13,038	90%
Geological and geophysical	912	4,171	3,259	78%
Unproved leasehold	31,618	21,412	(10,206)	(48%)
Standby rig charges	20,084	—	(20,084)	n/a
Other	3,743	2,418	(1,325)	(55%)
	$57,754	$42,436	$(15,318)	(36%)

In 2009, dry hole costs and geological and geophysical expenses were significantly decreased due to our reduced drilling program. In 2008, the dry hole costs were primarily due to the write-off of six wells in the Appalachian region, which were non-economic. Unproved leasehold expense increased primarily as a result of a change we made to our accounting process in 2009 to amortize additional insignificant unproved properties over the average estimated life of the leases rather than amortizing some leases and assessing other leases on an occurrence basis. In conjunction with the drilling program reduction, we amended certain drilling rig contracts to delay commencement of drilling until January 2010. As a result, in 2009 we recognized standby rig charges for cancellation fees, minimum daily standby fees and demobilization fees as a component of exploration expenses. Other expenses increased due to increased delay rentals in the Gulf Coast region primarily related to lease renewals on certain prospects.

Depreciation, Depletion and Amortization (DD&A)

DD&A expenses increased approximately $11.6 million due to the increase in equivalent production and approximately $6.5 million due to higher depletion rates which were caused by higher cost wells being drilled. Our average depletion rate increased by $0.13 per Mcfe, or 5%, from $2.82 per Mcfe in 2008 to $2.95 per Mcfe in 2009.

Impairments

Impairment charges in 2009 includes $97.5 million attributable to assets that were sold during 2009 or held for sale as of December 31, 2009. The most significant of these related to our Gulf Coast properties in Texas and Louisiana as well as certain properties in North Dakota. The sale of our North Dakota properties was completed in the fourth quarter of 2009 and the sale of our Gulf Coast properties was completed in January 2010. See Note 19 to the Consolidated Financial Statements for additional information with respect to the Gulf Coast assets held for sale. Other impairment charges during 2009 include $4.1 million for re-evaluation related to our tubular inventory due to decline in market value and $4.8 million of other impairments. Impairment charges in 2008 related to declines in spot and future oil and gas prices which reduced the estimated reserve bases of fields on certain properties in the Mid-Continent and Appalachian regions. These changes in reserve estimates in 2008 were primarily due to a decrease in fourth quarter oil and gas prices and a decline in well performance.

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

The following table sets forth a summary of certain financial operating performance and other data for our oil and gas segment for the periods presented:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Favorable (Unfavorable)	% Change
Revenues				
Natural gas	$368,801	$262,169	$106,632	41%
Crude oil	46,529	22,439	24,090	107%
NGL	21,292	5,678	15,614	275%
Total product revenues	436,622	290,286	146,336	50%
Gain on sale of property and equipment	30,634	12,235	18,399	150%
Other income	2,074	720	1,354	188%
Total revenues	469,330	303,241	166,089	55%
Expenses				
Operating	59,459	46,713	(12,746)	(27%)
Taxes other than income	23,336	17,847	(5,489)	(31%)
General and administrative	21,284	16,281	(5,003)	(31%)
Production costs	104,079	80,841	(23,238)	(29%)
Exploration	42,436	28,608	(13,828)	(48%)
Depreciation, depletion and amortization	132,276	87,223	(45,053)	(52%)
Impairments	19,963	2,586	(17,377)	(672%)
Total expenses	298,754	199,258	(99,496)	(50%)
Operating income	$170,576	$103,983	$ 66,593	64%
Production:				
Natural gas (MMcf)	41,493	37,802	3,691	10%
Crude oil (MBbl)	506	325	181	56%
NGL (MBbl)	392	136	256	188%
Total production (MMcfe)	46,881	40,569	6,312	16%
Rates:				
Natural gas ($/Mcf)	$ 8.89	$ 6.94	$ 1.95	28%
Crude oil ($/Bbl)	91.95	69.04	22.91	33%
NGL ($/Bbl)	54.32	41.75	12.57	30%
Total ($/Mcfe)	$ 9.31	$ 7.16	$ 2.16	30%

Production

The following tables set forth a summary of our production volume and product revenue by geographical region for the periods presented:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Favorable (Unfavorable)	% Change
	(MMcfe)			
East Texas	13,409	7,986	5,423	68%
Appalachia	11,497	12,426	(929)	(7%)
Mid-Continent	7,646	4,129	3,517	85%
Mississippi	7,340	7,551	(211)	(3%)
Gulf Coast	6,989	8,477	(1,488)	(18%)
Total production	46,881	40,569	6,312	16%

	Year Ended December 31, 2008	2007	Favorable (Unfavorable)	% Change
East Texas	$129,105	$ 59,333	$ 69,772	118%
Appalachia	107,282	86,936	20,346	23%
Mid-Continent	59,969	24,980	34,989	140%
Mississippi	69,916	53,737	16,179	30%
Gulf Coast	70,350	65,300	5,050	8%
Total revenues	$436,622	$290,286	$146,336	50%

Approximately 89% and 93% of total production in the years ended December 31, 2008 and 2007 was natural gas. The increased production in the East Texas region is due primarily to aggressive drilling and additional processing for sales points which were previously sold as wet gas, but are now processed through PVR's Crossroads plant, which was placed into service in April 2008. In 2008, we drilled a successful horizontal Lower Bossier (Haynesville) Shale well in Harrison County, Texas. Based on this successful horizontal test, we had four rigs drilling horizontal Lower Bossier (Haynesville) Shale wells as of December 31, 2008. The decrease in the Appalachian region is due primarily to the sale of oil and gas royalty interests to PVR in October 2007. Production in the Mississippi region was relatively constant from 2007 to 2008. The increase in production in the Mid-Continent region is due primarily to higher CBM production and high production wells in the Granite Wash and Woodford Shale areas. The decrease in production in the Gulf Coast region is due primarily to decreased natural gas production resulting from depletion of certain prospects within that region. In addition, the Gulf Coast region, particularly the Bayou Postillion area, experienced disruptions in production due to inclement weather.

In 2008, we drilled a total of 285 gross (179.6 net) wells, including 274 gross (172.3 net) development wells and 12 gross (7.3 net) exploratory wells. All wells were successful except (i) 15 gross (11.8 net) development wells, including 11 gross (8.8 net) development wells under evaluation at December 31, 2008 and (ii) 6 gross (3.8 net) exploratory wells, including one exploratory well that was under evaluation at December 31, 2008.

Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects. In the Lower Bossier (Haynesville) play, we drilled 102 gross (76.4 net) wells in 2008, including 93 gross (68.4 net) successful wells. In Appalachia, we drilled 75 gross (33.1 net) wells in 2008, including 18 gross (9.0 net) horizontal CBM locations and 71 gross (30.6 net) successful locations. In the Selma Chalk play in Mississippi, we drilled 29 gross (28.6 net) wells in 2008, including 28 gross (27.6 net) successful horizontal wells. We also have unconventional development programs in the Mid-Continent and some higher-impact exploratory prospects in the Gulf Coast. In the Mid-Continent region, we drilled 75 gross (37.7 net) wells in 2008, including 29 gross (23.9 net) successful CBM locations.

In 2007, we drilled a total of 289 gross (213.0 net) wells, including 271 gross (203.6 net) development wells and 18 gross (9.4 net) exploratory wells. All wells were successful except six gross (5.1 net) development wells and seven gross (4.2 net) exploratory wells, including four (2.6 net) wells under evaluation at December 31, 2007.

Revenues

The following table provides an analysis of the change in our oil and gas segment revenues for the year ended December 31, 2008 as compared to the year ended December 31, 2007:

	2008 Revenue Variance Due to		
	Volume	Price	Total
Natural gas	$25,598	$81,034	$106,632
Crude oil	12,497	11,593	24,090
NGL	10,688	4,926	15,614
	$48,783	$97,553	$146,336

Effects of Derivatives

In 2006, we discontinued hedge accounting prospectively for our remaining and future commodity derivatives. Consequently, we began recognizing realized and mark-to-market gains and losses in the derivatives line of our Consolidated Statements of Income rather than deferring such amounts in accumulated other comprehensive income. However, realized gains and losses and changes in the fair value of derivatives entered into prior to the election to discontinue hedge accounting continued to be deferred in accumulated other comprehensive income until the original forecasted transactions settled in 2007. Accordingly, the natural gas, crude oil and NGL revenues for 2007 include amounts, as indicated in the table below, for derivative gains and losses attributable to settlements during 2007. For the derivatives related to the oil and gas segment, we paid $7.6 million in cash settlements in 2008 and we received cash settlements of $14.1 million in 2007. The following table reconciles natural gas and crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Favorable	
	2008	2007	(Unfavorable)	% Change
Natural gas revenues as reported	$368,801	$262,169	$106,632	41%
Derivative gains included in natural gas revenues	—	(222)	222	(100%)
Natural gas revenues before impact of derivatives	368,801	261,947	106,854	41%
Cash settlements on natural gas derivatives	(7,339)	14,863	(22,202)	(149%)
Natural gas revenues adjusted for derivatives	$361,462	$276,810	$ 84,652	31%
Natural gas revenue rates per Mcf, as reported	$ 8.89	$ 6.94	$ 1.95	28%
Derivative gains included in natural gas revenues	—	(0.01)	0.01	(100%)
Natural gas revenues before impact of derivatives	8.89	6.93	1.96	28%
Cash settlements on natural gas derivatives	(0.18)	0.39	(0.57)	(145%)
Natural gas revenue rates per Mcf adjusted for derivatives	$ 8.71	$ 7.32	$ 1.39	19%
Crude oil revenues as reported	$ 46,529	$ 22,439	$ 24,090	107%
Derivative gains included in crude oil revenues	—	502	(502)	(100%)
Crude oil revenues before impact of derivatives	46,529	22,941	23,588	103%
Cash settlements on crude oil derivatives	(281)	(735)	454	(62%)
Crude oil revenues adjusted for derivatives	$ 46,248	$ 22,206	$ 24,042	108%
Crude oil revenues as reported	$ 91.95	$ 69.04	$ 22.91	33%
Derivative gains included in crude oil revenues	—	1.54	(1.54)	(100%)
Crude oil revenues before impact of derivatives	91.95	70.58	21.37	30%
Cash settlements on crude oil derivatives	(0.55)	(2.26)	1.71	(76%)
Crude oil revenues adjusted for derivatives	$ 91.40	$ 68.32	$ 23.08	34%

Gain on Sale of Property and Equipment

In 2008, we recognized gains on the sales of property and equipment, primarily related to the sale of all of our working interest in unproved properties in Louisiana. In 2007, we recognized a gain on the sale property and equipment primarily related to the September 2007 sale of non-operated working interests in oil and gas properties.

Other Income

Other income increased primarily due to increased gathering revenues in the East Texas region resulting from increased production in that region and an overall increase in gathering fees per Mcf that we charged.

Production Costs

The following table sets forth a summary of our production costs per Mcfe for the periods presented:

	Year Ended December 31,		Favorable	
	2008	2007	(Unfavorable)	% Change
Operating	$1.27	$1.15	$(0.12)	(10%)
Taxes other than income	0.50	0.44	(0.06)	(13%)
General and administrative	0.45	0.40	(0.05)	(13%)
Total production costs per Mcfe	$2.22	$1.99	(0.23)	(11%)

Operating expenses increased primarily due to increased compressor rentals in East Texas and in the Mid-Continent region related to increased production and capital expenditures in those regions; increased repairs and maintenance expenses in the Mississippi, Mid-Continent and East Texas regions; and new processing fees related to the Crossroads plant, which began operations in the second quarter of 2008. Taxes other than income increased, primarily due to an increase in severance and ad valorem taxes related to higher commodity prices and increased production. General and administrative expenses increased primarily due to increased staffing costs in the East Texas and Mid-Continent regions.

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31,		Favorable	
	2008	2007	(Unfavorable)	% Change
Dry hole costs	$14,435	$11,689	$ (2,746)	(23%)
Geological and geophysical	4,171	2,769	(1,402)	(51%)
Unproved leasehold	21,412	13,036	(8,376)	(64%)
Other	2,418	1,114	(1,304)	(117%)
	$42,436	$28,608	$(13,828)	(48%)

In 2008, the dry hole costs were primarily due to the write-off of six wells in the Appalachian region, which were non-economic. In 2007, the dry hole costs were primarily due to the write-off of three exploratory wells in the Gulf Coast region and one exploratory well in the East Texas region. Geological and geophysical expenses increased due to seismic expenses incurred primarily in East Texas and South Louisiana, which was driven by increased growth of drilling prospects. Unproved leasehold expenses increased primarily due to the abandonment of property in the Mid-Continent and Appalachian regions. Other expenses increased due to increased delay rentals in the Gulf Coast region primarily related to lease renewals on certain prospects.

Depreciation, Depletion and Amortization

DD&A expenses increased primarily due to the increase in equivalent production and higher depletion rates. Our average depletion rate increased by $0.67 per Mcfe, or 31%, from $2.15 per Mcfe in 2007 to $2.82 per Mcfe in 2008 due to increased drilling costs in the East Texas and Mid-Continent regions and revisions in reserve estimates. The higher drilling costs were due primarily to increased drilling rig day rates and increased steel costs.

Impairments

Impairment charges in 2008 related to declines in spot and future oil and gas prices which reduced the estimated reserve bases of fields on certain properties in the Mid-Continent and Appalachian regions. These changes in reserve estimates in 2008 were primarily due to a decrease in fourth quarter oil and gas prices and a decline in well performance. Impairment charges in 2007 related to changes in estimates of the reserve bases of fields on certain properties in the Gulf Coast and Mid-Continent regions. These changes in reserve estimates were primarily due to declines in well performance.

PVR Coal and Natural Resource Management Segment

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

The following table sets forth a summary of certain financial and other data for the PVR coal and natural resource management segment and the percentage change for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Revenues				
Coal royalties	$120,435	$122,834	$(2,399)	(2%)
Coal services	7,332	7,355	(23)	(0%)
Timber	5,726	6,943	(1,217)	(18%)
Oil and gas royalty	2,471	5,989	(3,518)	(59%)
Other	8,636	10,206	(1,570)	(15%)
Total revenues	144,600	153,327	(8,727)	(6%)
Expenses				
Coal royalties	5,768	9,534	3,766	40%
Other operating	2,892	2,406	(486)	(20%)
Taxes other than income	1,704	1,680	(24)	(1%)
General and administrative	13,867	12,606	(1,261)	(10%)
Impairments	1,511	—	(1,511)	n/a
Depreciation, depletion and amortization	31,330	30,805	(525)	(2%)
Total expenses	57,072	57,031	(41)	(0%)
Operating income	$ 87,528	$ 96,296	$(8,768)	(9%)
Coal royalty tons by region				
Central Appalachia	18,319	19,587	(1,268)	(6%)
Northern Appalachia	3,786	3,578	208	6%
Illinois Basin	4,724	4,584	140	3%
San Juan Basin	7,501	5,941	1,560	26%
Total	34,330	33,690	640	2%
Coal royalties revenue by region				
Central Appalachia	$ 85,183	$ 93,577	$(8,394)	(9%)
Northern Appalachia	6,931	6,568	363	6%
Illinois Basin	12,420	10,451	1,969	19%
San Juan Basin	15,901	12,238	3,663	30%
	$120,435	$122,834	$(2,399)	(2%)
Less coal royalties expenses(1)	(5,768)	(9,534)	3,766	(40%)
Net coal royalties revenues	$114,667	$113,300	$ 1,367	1%
Coal royalties per ton by region ($/ton)				
Central Appalachia	$ 4.65	$ 4.78	$ (0.13)	(3%)
Northern Appalachia	1.83	1.84	(0.01)	(1%)
Illinois Basin	2.63	2.28	0.35	15%
San Juan Basin	2.12	2.06	0.06	3%
	3.51	3.65	$ (0.14)	(4%)
Less coal royalties expenses(1)	(0.17)	(0.28)	0.11	(39%)
Net coal royalties revenues	$ 3.34	$ 3.37	$ (0.03)	(1%)

(1) PVR's coal royalties expense is incurred primarily in the Central Appalachian region.

Revenues

Coal royalties revenues decreased slightly due to the decrease in the average coal royalty received per ton. This decrease was due to an overall shift in production mix to lower royalty lessees, primarily to fixed rate leases in the San Juan Basin from the higher royalty Central Appalachian region.

Coal production by PVR's lessees increased slightly due to higher production in the San Juan Basin resulting from the start up of a second mine and improved mining conditions. This increase was partially offset by a decline in production in the Central Appalachian region which was due to a reduction in longwall mining activity and a depressed coal market.

Timber revenues decreased due to lower sales prices resulting from weakened market conditions for furniture-grade wood products. The average price received by PVR for timber decreased 27% from $287 per Mbf in 2008 to $209 per Mbf in 2009.

The oil and gas royalty revenues decrease was primarily attributable to lower natural gas prices in 2009. Realized prices received for natural gas decreased 57% from $10.63 per Mcf in 2008 to $4.55 per Mcf in 2009.

Other revenues, which consisted primarily of wheelage fees, forfeiture income and management fees, decreased due to lower wheelage income from a decline in coal production in certain areas. In addition, in 2008, a $0.8 million gain on the settlement of unmined coal was recognized.

Expenses

Coal royalties expenses decreased due to a decline in mining activity by PVR's lessees from subleased properties in the Central Appalachian region where PVR's coal royalties expense is primarily incurred. Mining activity on PVR's subleased property fluctuates between periods due to the proximity of PVR's property boundaries and other mineral owners.

General and administrative expenses increased as a result of an uncollectible account receivable resulting from a PVR lessee bankruptcy and increased staffing and related benefit costs.

The $1.5 million impairment expense in 2009 was the result of a reduction in the value of an intangible asset. PVR tests long-lived assets for impairment if a triggering event occurs and the impairment was triggered by a wheelage contract being rejected in bankruptcy. As a result of the impairment, the fair value of the contract has been reduced to zero.

DD&A expenses increased slightly due to higher depletion expense resulting from the increase in coal mined from PVR's properties by its lessees. On a per ton basis, DD&A remained constant at $0.91 per ton for both periods.

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

The following table sets forth a summary of certain financial and other data for the PVR coal and natural resource management segment and the percentage change for the periods presented:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Favorable (Unfavorable)	% Change
Revenues				
Coal royalties	$122,834	$ 94,140	$ 28,694	30%
Coal services	7,355	7,252	103	1%
Timber	6,943	1,711	5,232	306%
Oil and gas royalty	5,989	1,864	4,125	221%
Other	10,206	6,672	3,534	53%
Total revenues	153,327	111,639	41,688	37%
Expenses				
Coal royalties	9,534	5,540	(3,994)	(72%)
Other operating	2,406	2,531	125	5%
Taxes other than income	1,680	1,110	(570)	(51%)
General and administrative	12,606	10,957	(1,649)	(15%)
Depreciation, depletion and amortization	30,805	22,690	(8,115)	(36%)
Total expenses	57,031	42,828	(14,203)	(33%)
Operating income	$ 96,296	$ 68,811	$ 27,485	40%
Coal royalty tons by region				
Central Appalachia	19,587	18,827	760	4%
Northern Appalachia	3,578	4,194	(616)	(15%)
Illinois Basin	4,584	3,779	805	21%
San Juan Basin	5,941	5,728	213	4%
Total	33,690	32,528	1,162	4%
Coal royalties revenue by region				
Central Appalachia	$ 93,577	$ 68,815	$ 24,762	36%
Northern Appalachia	6,568	6,434	134	2%
Illinois Basin	10,451	7,432	3,019	41%
San Juan Basin	12,238	11,459	779	7%
	$122,834	$ 94,140	$ 28,694	30%
Less coal royalties expenses(1)	(9,534)	(5,540)	(3,994)	72%
Net coal royalties revenues	$113,300	$ 88,600	$ 24,700	28%
Coal royalties per ton by region ($/ton)				
Central Appalachia	$ 4.78	$ 3.66	$ 1.12	31%
Northern Appalachia	1.84	1.53	0.31	20%
Illinois Basin	2.28	1.97	0.31	16%
San Juan Basin	2.06	2.00	0.06	3%
	3.65	2.89	$ 0.76	26%
Less coal royalties expenses(1)	(0.28)	(0.17)	(0.11)	65%
Net coal royalties revenues	$ 3.37	$ 2.72	$ 0.65	24%

(1) PVR's coal royalties expense is incurred primarily in the Central Appalachian region.

Revenues

Coal royalties revenues increased as a result of higher coal prices and additional tons being mined by PVR's lessees. Coal royalty tons increased primarily due to higher production in the Central Appalachia and Illinois Basin regions, partially offset by a production decline in the Northern Appalachian region. The Central Appalachian region increase was the result of longwall mining and the timing of additional mining equipment added to PVR's properties during 2008. The Illinois Basin region increase was primarily due to a full year of production in 2008 on coal reserves which were acquired by PVR in June 2007. The Northern Appalachian region decrease was a result of adverse longwall mining conditions.

Coal prices were higher on average due to international coal shortages on both the metallurgical and steam markets, which not only drove increases in export metallurgical pricing, but also allowed some higher thermal capacity steam coal to crossover into the metallurgical market; consequently, this caused the domestic steam coal markets to tighten and resulted in higher domestic pricing. PVR's coal royalties revenues are dependent on the prevailing coal prices received by its lessees, which are affected by numerous factors that are generally beyond PVR's control. Coal prices are generally determined by national and regional supply and demand.

Timber revenues increased due to increased harvesting from PVR's September 2007 forestland acquisition. The average price received for timber increased 20% from $240 per Mbf in 2007 to $287 per Mbf in 2008.

The oil and gas royalty revenues increase was primarily due to the increased royalties resulting from PVR's October 2007 oil and gas royalty interest acquisition from us. Realized prices received for natural gas increased 31% from $8.11 per Mcf in 2007 to $10.63 per Mcf in 2008.

Other revenues increased primarily due to increased coal transportation, or wheelage, fees attributable to greater production, increased forfeiture income and the recognition of a $0.8 million gain on the settlement of unmined coal.

Expenses

Coal royalties expenses increased due to additional mining by PVR's lessees from subleased properties in the Central Appalachian region.

Taxes other than income increased primarily due to increased severance taxes resulting from PVR's September 2007 forestland acquisition and October 2007 oil and gas royalty interest acquisition.

General and administrative expenses increased primarily due to increased staffing and related benefit costs.

DD&A expenses increased due to increased depletion resulting from PVR's September 2007 forestland acquisition, October 2007 oil and gas royalty interest acquisition and May 2008 coal reserves and forestland acquisition. A discussion of DD&A methodologies is provided in the Critical Accounting Estimates that follows.

PVR Natural Gas Midstream Segment

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

The following table sets forth a summary of certain financial and other data for the PVR natural gas midstream segment and the percentage change for the periods presented:

	Year Ended December 31,		Favorable	
	2009	2008	(Unfavorable)	% Change
Revenues				
Residue gas	$289,427	$452,535	$(163,108)	(36%)
Natural gas liquids	182,794	229,765	(46,971)	(20%)
Condensate	17,010	26,009	(8,999)	(35%)
Gathering, processing and transportation fees	15,558	11,693	3,865	33%
Total natural gas midstream revenues(1)	504,789	720,002	(215,213)	(30%)
Equity earnings in equity investment	5,548	2,408	3,140	130%
Producer services	1,767	5,843	(4,076)	(70%)
Total revenues	512,104	728,253	(216,149)	(30%)
Expenses				
Cost of midstream gas purchased(1)	406,583	612,530	205,947	34%
Operating	26,451	20,737	(5,714)	(28%)
Taxes other than income	3,090	2,578	(512)	(20%)
General and administrative	16,301	14,300	(2,001)	(14%)
Impairments	—	31,801	31,801	100%
Depreciation and amortization	38,905	27,361	(11,544)	(42%)
Total operating expenses	491,330	709,307	217,977	31%
Operating income	$ 20,774	$ 18,946	$ 1,828	10%
Operating Statistics				
System throughput volumes (MMcf)	121,335	98,683	22,652	23%
Daily throughput volumes (MMcfd)	332	270	62	23%
Gross margin	$ 98,206	$107,472	$ (9,266)	(9%)
Cash impact of derivatives	10,566	(31,709)	42,275	133%
Gross margin, adjusted for impact of derivatives	$108,772	$ 75,763	$ 33,009	44%
Gross margin ($/Mcf)	$ 0.81	$ 1.09	$ (0.28)	(26%)
Cash impact of derivatives ($/Mcf)	0.09	(0.32)	0.41	128%
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.90	$ 0.77	$ 0.13	17%

(1) In 2009 and 2008, PVR recorded $72.5 million and $127.9 million of natural gas midstream revenue and $72.5 million and $127.9 million for the cost of midstream gas purchased related to the purchase of natural gas from our subsidiary PVOG LP, and the subsequent sale of that gas to third parties. PVR takes title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

Gross margin is the difference between PVR's natural gas midstream revenues and its cost of midstream gas purchased. Natural gas midstream revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from system throughput volumes received, condensate collected and sold and gathering and other fees primarily from natural gas volumes connected to PVR's gas processing plants. Cost of midstream gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

The gross margin decrease was a result of lower commodity pricing and lower fractionation, or frac spreads, partially offset by increased system throughput volumes and increased natural gas processing capacity. Frac spreads are the difference between the price of NGLs sold and the cost of natural gas purchased on a per MMBtu basis.

Drilling activities by producers central to PVR's natural gas gathering and processing plants were at reduced levels from the previous year due to lower natural gas prices. However, PVR's 2009 system throughput volumes benefited from the results of drilling activity in 2008 and the first part of 2009. PVR's expansion and acquisition activity, especially in the Panhandle System, has alleviated pipeline pressures and allowed PVR to move all of its gas in this region to its processing plants. As noted above, in July 2009 PVR completed an acquisition of gas processing and residue pipeline facilities in western Oklahoma. The acquired assets included the 60 MMcfd Sweetwater plant. Additionally, PVR completed a 40 MMcfd processing plant expansion in its Spearman complex that was put into service on July 31, 2009. The acquired and expanded processing facilities increased PVR's processing capacity in the Panhandle System to 260 MMcfd and overall processing capacity to 400 MMcfd. The increased processing capacity has allowed PVR to process natural gas volumes that were being bypassed due to processing capacity constraints in the Panhandle System and has alleviated pipeline pressure-related volume constraints in the eastern portion of the Panhandle.

During 2009, PVR generated a majority of its gross margin from contractual arrangements under which the gross margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business — Contracts — PVR Natural Gas Midstream Segment," for discussion of the types of contracts utilized by the PVR natural gas midstream segment. As part of PVR's risk management strategy, it uses derivative financial instruments to economically hedge NGLs sold and natural gas purchased. See Note 8 to the Consolidated Financial Statements for a description of PVR's derivatives program. On a per Mcf basis, adjusted for the impact of PVR's commodity derivative instruments, PVR's gross margin increased in 2009 by $0.13, or 17%. This favorable impact of commodity derivatives is a result of overall lower commodity prices during 2009 and the expiration of older derivative instruments.

Revenues Other Than Gross Margin

Equity earnings in equity investment increased due to a full year of results in 2009 compared with a partial year in 2008. In April 2008, PVR acquired a 25% member interest in Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin. In addition, revenues from the joint venture have grown in 2009 due to mainline volume increases in the Powder River Basin.

Producer services revenues decreased due to a negative relative change in the natural gas indices on which PVR's purchases and sales of natural gas are based and a decrease in marketing fees resulting from lower commodity prices.

Expenses

Operating expenses increased due to PVR's prior and current years' acquisitions, expansion projects, compressor rentals and labor costs. Increased costs for compressor rentals and labor costs were incurred due to expanding PVR's footprint in the Panhandle System.

Taxes other than income increased due to higher property taxes. The increase in property taxes was a result of PVR's acquisitions and plant expansions.

General and administrative expenses increased due to increased staffing and related benefit costs. The increase was primarily attributable to labor costs resulting from PVR's 2008 acquisitions and plant expansions. PVR incurred a full year of salaries and benefits in 2009 compared with a partial year in 2008.

Impairment expense in 2008 was the result of a reduction in the value of goodwill. PVR tests goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. The goodwill testing during the fourth quarter of 2008 identified a goodwill impairment loss of $31.8 million. The impairment charge, which was triggered by fourth quarter declines in oil and gas spot and futures prices and a decline in PVR's market capitalization, reduced to zero all goodwill recorded in conjunction with acquisitions made by the PVR natural gas midstream segment in 2008 and prior years.

Depreciation and amortization expenses increased primarily due to PVR's acquisitions, capital expansions on the Spearman and Sweetwater plants and new well connections in existing areas of operation.

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

The following table sets forth a summary of certain financial and other data for the PVR natural gas midstream segment and the percentage change for the periods presented:

	Year Ended December 31,		Favorable	
	2008	2007	(Unfavorable)	% Change
Revenues				
Residue gas	$452,535	$242,129	$ 210,406	87%
Natural gas liquids	229,765	172,144	57,621	33%
Condensate	26,009	13,889	12,120	87%
Gathering, processing and transportation fees	11,693	5,012	6,681	133%
Total natural gas midstream revenues(1)	720,002	433,174	286,828	66%
Equity earnings in equity investment	2,408	—	2,408	n/a
Producer services	5,843	4,632	1,211	26%
Total revenues	728,253	437,806	290,447	66%
Expenses				
Cost of midstream gas purchased(1)	612,530	343,293	(269,237)	(78%)
Operating	20,737	12,893	(7,844)	(61%)
Taxes other than income	2,578	1,926	(652)	(34%)
General and administrative	14,300	11,958	(2,342)	(20%)
Impairments	31,801	—	(31,801)	n/a
Depreciation and amortization	27,361	18,822	(8,539)	(45%)
Total operating expenses	709,307	388,892	(320,415)	(82%)
Operating income	$ 18,946	$ 48,914	$ (29,968)	(61%)
Operating Statistics				
System throughput volumes (MMcf)	98,683	67,810	30,873	46%
Daily throughput volumes (MMcfd)	270	186	84	45%
Gross margin	$107,472	$ 89,881	$ 17,591	20%
Cash impact of derivatives	(31,709)	(13,184)	(18,525)	(141%)
Gross margin, adjusted for impact of derivatives	$ 75,763	$ 76,697	$ (934)	(1%)
Gross margin ($/Mcf)	$ 1.09	$ 1.33	$ (0.24)	(18%)
Cash impact of derivatives ($/Mcf)	(0.32)	(0.19)	(0.13)	(68%)
Gross margin, adjusted for impact of derivatives ($/Mcf)	$ 0.77	$ 1.14	$ (0.37)	(32%)

(1) In 2008, PVR recorded $127.9 million of natural gas midstream revenue and $127.9 million for the cost of midstream gas purchased related to the purchase of natural gas from our subsidiary PVOG LP, and the subsequent sale of that gas to third parties. PVR takes title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin.

Gross Margin

Gross margin is the difference between PVR's natural gas midstream revenues and its cost of midstream gas purchased. Natural gas midstream revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from system throughput volumes received, condensate collected and sold and gathering and other fees primarily from natural gas volumes connected to PVR's gas processing plants. Cost of midstream gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage-of-proceeds and gas purchase/keep-whole contracts.

The gross margin increase was a result of higher commodity pricing, increased system throughput volume production and higher frac spreads during 2008 compared to 2007.

The system throughput volumes increase is due primarily to PVR's Crossroads plant in East Texas, which became fully operational in 2008, and to the Lone Star acquisition, which was consummated in the third quarter of 2008. Also, the continued development by producers operating in the vicinity of the Panhandle System, as well as PVR's success in contracting and connecting new supply contributed to the increase in throughput volume.

During 2008, PVR generated a majority of its gross margin from contractual arrangements under which the gross margin is exposed to increases and decreases in the price of natural gas and NGLs. See Item 1, "Business — Contracts — PVR Natural Gas Midstream Segment," for discussion of the types of contracts utilized by the PVR natural gas midstream segment. As part of PVR's risk management strategy, it uses derivative financial instruments to economically hedge NGLs sold and natural gas purchased. See Note 8 to the Consolidated Financial Statements for a description of PVR's derivatives program. On a per Mcf basis, adjusted for the impact of PVR's commodity derivative instruments for which it discontinued hedge accounting in 2006, PVR's gross margin decreased by $0.37, or 32%. Gross margins during the first part of 2008 continued to increase given the favorable pricing environment, such as higher commodity prices and frac spreads, and increased system throughput volumes. However, margins decreased towards the end of 2008 due to a significant decrease in the prices of NGLs as a result of reduced industrial demand in a weakening economy. The gross margin on a per Mcf basis decreased in 2008 due to an increase in fee-based system throughput volumes. These increased volumes are associated with PVR's 2008 expansions and acquisitions.

Revenues Other Than Gross Margin

Equity earnings in equity investment increased due to PVR's April 2008 acquisition of a 25% member interest in Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin. PVR acquired the member interest in April 2008.

Producer services revenues increased due to an increase in agent fees for the marketing of Penn Virginia's and third parties' natural gas production. Agent fees increased primarily due to increases in Penn Virginia's natural gas production as well as increases in the price of natural gas.

Expenses

Operating expenses increased due to expenses related to PVR's expanding footprint in areas of operation, including acquisitions and the addition of the Spearman and Crossroads plants. These expenses include increased repairs and maintenance expenses, increased compressor rentals, chemical and treating expenses and increased labor costs.

Taxes other than income decreased due to higher property taxes. The increase in property taxes was a result of PVR's acquisitions and plant expansions.

General and administrative expenses increased due to increased staffing and related benefit costs. The increase in personnel was primarily attributable to PVR's acquisitions, plant expansions and well connects in established areas of operation.

Impairment expense in 2008 was the result of a reduction in the value of goodwill. PVR tests goodwill for impairment on an annual basis, at a minimum, and more frequently if a triggering event occurs. The goodwill testing during the fourth quarter of 2008 identified a goodwill impairment loss of $31.8 million. The impairment loss, which was triggered by fourth quarter declines in oil and gas spot and futures prices and a decline in PVR's market capitalization, reduced to zero all goodwill recorded in conjunction with acquisitions made by the PVR natural gas midstream segment in 2008 and prior years.

Depreciation and amortization expenses increased primarily due to capital expansions on the Spearman and Crossroads plants and acquisitions.

Eliminations and Other

Year Ended December 31, 2009 Compared With Year Ended December 31, 2008

The following table presents a reconciliation of our reporting segments' operating income (loss) to net income (loss) attributable to Penn Virginia for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Operating income (loss) from segments	$ (67,691)	$285,818	$(353,509)	(124%)
Operating loss from Eliminations and other	(30,511)	(28,995)	(1,516)	5%
Operating income (loss)	(98,202)	256,823	(355,025)	(138%)
Other income (expense)				
Interest expense	(68,884)	(49,299)	(19,585)	40%
Derivatives	11,854	46,582	(34,728)	(75%)
Other	2,612	(666)	3,278	(492%)
Income tax (expense) benefit	75,252	(71,920)	147,172	(205%)
Net income (loss)	(77,368)	181,520	(258,888)	(143%)
Less:				
Net income attributable to noncontrolling interests	(37,275)	(60,436)	23,161	(38%)
Net income (loss) attributable to Penn Virginia Corporation	$(114,643)	$121,084	$(235,727)	(195%)

The operating loss from eliminations and other is primarily attributable to corporate expenses which consist of general and administrative expenses other than from our operating segments. Corporate expenses increased in 2009 primarily due to higher salaries and benefits as well as higher depreciation expense. Compensation-based increases are attributable to the recognition of additional stock-based compensation expense, while the increase in depreciation is attributable to software development projects.

Interest Expense

Interest expense increased primarily as a result of higher interest rates on outstanding borrowings, including the Senior Notes, which were issued in June 2009. Also, we realized higher amortization of the original issue discount and issuance costs on the Senior Notes and Convertible Notes as well as higher amortization of issuance costs associated with the Revolver and PVR Revolver. In addition, capitalized interest declined during 2009 primarily as a result of our and PVR's reduced capital expenditures programs. See Note 21 to the Consolidated Financial Statements for additional detail.

Derivatives

The components of our and PVR's derivative activities are presented below for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Oil and gas unrealized derivative gain (loss)	$(26,690)	$ 37,365	$(64,055)	(171%)
Oil and gas realized gain (loss)	59,908	(7,620)	67,528	(886%)
Interest rate swap unrealized gain	111	—	111	n/a
Interest rate swap realized loss	(1,761)	—	(1,761)	n/a
PVR Midstream unrealized derivative gain (loss)	(25,974)	62,661	(88,635)	(141%)
PVR Midstream realized gain (loss)	10,566	(37,189)	47,755	(128%)
PVR interest rate swap unrealized gain (loss)	3,260	(7,358)	10,618	(144%)
PVR interest rate swap realized gain (loss)	(7,566)	(1,277)	(6,289)	492%
	$ 11,854	$ 46,582	$(34,728)	(75%)

Derivative activity is primarily due to volatility in the natural gas, NGL and crude oil prices. We determine the fair value of our and PVR's commodity derivative agreements using quoted forward prices for these commodities. Cash received for settlements during 2009 was $61.1 million as compared to cash payments for settlement of $46.1 million during 2008.

Other

Other income, which primarily consists of interest income and gains and losses on non-operating securities, increased during 2009 primarily as a result of a $3.8 million make-whole payment recorded during 2008 in connection with PVR's prepayment of its notes.

Income Tax Expense

Due to the operating losses incurred during 2009, we recognized an income tax benefit as compared to income tax expense during 2008. The effective tax benefit rate for 2009 was 39.6% as compared to an effective tax rate of 37.3% for 2008. We expect to realize any income tax benefits created in 2009 by amending prior year tax returns and carrying forward any excess income tax benefits.

Noncontrolling Interests

Noncontrolling interests represent net income allocated to the limited partners of PVG owned by the public. The decrease in net income attributable to noncontrolling interests during 2009 is directly attributable to a decrease in PVG's net income, primarily attributable to a decrease in PVR's operating income and other expenses as referenced above, partially offset by the effect of our reduced ownership interest in PVG. In September 2009, we sold 10 million of our PVG common units, which reduced our ownership in PVG from 77.0% to 51.4%.

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

The following table presents a reconciliation of our reporting segments' operating income (loss) to net income (loss) attributable to Penn Virginia for the periods presented:

	Year Ended December 31,		Favorable	
	2008	2007	(Unfavorable)	% Change
Operating income from segments	$285,818	$221,708	$ 64,110	29%
Operating loss from Eliminations and other	(28,995)	(29,084)	89	(0%)
Operating income	256,823	192,624	64,199	33%
Other income (expense)				
Interest expense	(49,299)	(37,851)	(11,448)	30%
Derivatives	46,582	(47,282)	93,864	(199%)
Other	(666)	3,651	(4,317)	(118%)
Income tax expense	(71,920)	(30,332)	(41,588)	137%
Net income	181,520	80,810	100,710	125%
Less:				
Net income attributable to noncontrolling interests	(60,436)	(30,319)	(30,117)	99%
Net income attributable to Penn Virginia Corporation	$121,084	$ 50,491	$ 70,593	140%

Operating Loss from Eliminations and Other

The operating loss from eliminations and other is primarily comprised of corporate operating expenses including general and administrative expenses other than from our operating segments. Corporate operating expenses increased in 2008 primarily due to increased DD&A expenses resulting from capitalized costs incurred on a software development project.

Interest Expense

Interest expense increased in 2008 primarily as a result of the full year impact of interest and the accretion of original issue discount on our Convertible Notes which were issued at the end of 2007. In addition, we recognized $1.0 million in net hedging losses on the Previous Interest Rate Swaps in interest expense during 2008. Interest expense attributable to PVR's borrowings increased by $4.8 million primarily due to an increase in PVR's average debt balance from $289.3 million in 2007 to $478.5 million in 2008. PVR also recognized $1.7 million in net hedging losses on the PVR Interest Rate Swaps in interest expense during 2008.

Derivatives

The components of our and PVR's derivative activities are presented below for the periods presented:

	Year Ended December 31,			
	2008	2007	Favorable (Unfavorable)	% Change
Oil and gas unrealized derivative gain (loss)	$ 37,365	$(15,842)	$ 53,207	(336%)
Oil and gas realized gain (loss)	(7,620)	14,128	(21,748)	(154%)
PVR Midstream unrealized derivative gain (loss)	62,661	(27,789)	90,450	(325%)
PVR Midstream realized gain loss	(37,189)	(17,779)	(19,410)	109%
PVR interest rate swap unrealized loss	(7,358)	—	(7,358)	n/a
PVR interest rate swap realized loss	(1,277)	—	(1,277)	n/a
	$ 46,582	$(47,282)	$ 93,864	(199%)

Derivative activity reflects volatility experienced in 2008 primarily attributable to the developments in the commodity markets reflecting global economic declines.

Other

Other income, which primarily consists of interest income and gains and losses on non-operating securities, decreased during 2008 primarily as a result of a $3.8 million make-whole payment recorded during 2008 in connection with PVR's prepayment of its notes.

Income Tax Expense

The effective tax rate for 2008 was 37.3% as compared to an effective tax rate of 37.5% for 2007.

Environmental Matters

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

PVR's operations and those of its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of PVR's coal property leases impose liability on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. The lessees are bonded and have indemnified PVR against any and all future environmental liabilities. PVR regularly visits its coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. PVR's management believes that its operations and those of its lessees comply with existing laws and regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2009 and 2008, PVR's environmental liabilities were $1.0 million and $1.2 million, which represents PVR's best estimate of the liabilities as of those dates related to its coal and natural resource management and natural gas midstream businesses. PVR has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future. For a summary of the environmental laws and regulations applicable to PVR's operations, see Item 1, "Business-Government Regulation and Environmental Matters."

Critical Accounting Estimates

The process of preparing financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting policies which involve the judgment of our management.

Oil and Gas Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are those reserves that are expected to be recovered from new wells or undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

There are several factors which could change our estimates of oil and gas reserves. Significant rises or declines in product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs. Additionally, we perform impairment tests when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates. For the years ended December 31, 2009, 2008 and 2007, we recorded impairment charges related to our oil and gas segment properties of $102.3 million, $20.0 million and $2.6 million. See the discussions of Results of Operations — Oil and Gas Segment and Note 19 to the Consolidated Financial Statements for a further description of the impairment of our oil and gas properties.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not discover proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2009, the costs attributable to unproved properties were $73.1 million. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Depreciation, Depletion and Amortization

We determine depreciation and depletion of oil and gas producing properties by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset.

PVR depletes coal properties on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by PVR's own geologists and outside consultants. PVR's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. From time to time, PVR carries out core-hole drilling activities on its coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. PVR depletes timber using a methodology consistent with the units-of-production method, but that is based on the quantity of timber harvested. PVR determines depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. When PVR retires or sells an asset, we remove its cost and related accumulated depreciation and amortization from our Consolidated Balance Sheets. We record the difference between the net book value, net of any assumed asset retirement obligation, and proceeds from dispositions of property and equipment as a gain or loss.

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 20 years, the period in which benefits are derived from the contracts, relationships and rights-of-way, and are combined with property, plant and equipment and are reviewed for impairment. See Note 11 to the Consolidated Financial Statements for a more detailed description of our and PVR's intangible assets.

Derivative Activities

From time to time, we and PVR enter into derivative financial instruments to mitigate our exposure to natural gas, crude oil and NGL price volatility. The derivative financial instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of collars and three-way collars.

All derivative financial instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

We recognize changes in fair value in earnings currently in the derivatives line on the Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the estimate of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts. Our results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment. See Note 8 to the Consolidated Financial Statements for a further description of our and PVR's derivatives programs.

New Accounting Standards

See Note 3 to the Consolidated Financial Statements for a description of recent accounting standards.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we and PVR are exposed are as follows:

- Price Risk
- Interest Rate Risk

As a result of our and PVR's risk management activities as discussed below, we are also exposed to counterparty risk with financial institutions with whom we and PVR enter into these risk management positions. Sensitivity to these risks has heightened due to the state of the global economy, including financial and credit markets.

Price Risk

We produce and sell natural gas, crude oil, NGLs and coal. As a result, our financial results are affected when prices for these commodities fluctuate. Such effects can be significant. Our and PVR's price risk management programs permit the utilization of derivative financial instruments (such as futures, forwards, option contracts, costless collars, three-way collars and swaps) to seek to mitigate the price risks associated with fluctuations in natural gas, NGL and crude oil prices as they relate to our anticipated production and PVR's natural gas midstream business. The derivative financial instruments are placed with major financial institutions that we and PVR believe are of acceptable credit risk.

At December 31, 2009, we reported a commodity derivative asset related to our oil and gas segment of $14.5 million. The contracts underlying such commodity derivatives are with four counterparties, all of which are investment grade financial institutions, and over 50% of such commodity derivative asset is substantially concentrated with one of these counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of December 31, 2009. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

In 2009, we reported consolidated net derivative gains of $11.9 million. Because we and PVR no longer use hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently in the derivatives line item on our Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our and PVR's commodity derivative contracts. Our and PVR's results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment. See Note 8 to the Consolidated Financial Statements for a further description of our and PVR's derivatives programs.

Oil and Gas Segment

The following table lists our open mark-to-market commodity derivative agreements and their fair values as of December 31, 2009:

	Average Volume Per Day	Weighted Average Price			
		Additional Put Option	Floor	Ceiling	Fair Value
Natural Gas Costless Collars	**(in MMBtus)**		**(per MMBtu)**		
First Quarter 2010	35,000		$ 4.96	$ 7.41	$ 115
Second Quarter 2010	30,000		$ 5.33	$ 8.02	1,047
Third Quarter 2010	30,000		$ 5.33	$ 8.02	883
Fourth Quarter 2010	50,000		$ 5.65	$ 8.77	1,656
First Quarter 2011	50,000		$ 5.65	$ 8.77	307
Second Quarter 2011	30,000		$ 5.67	$ 7.58	787
Third Quarter 2011	30,000		$ 5.67	$ 7.58	553
Fourth Quarter 2011	20,000		$ 6.00	$ 8.50	469
First Quarter 2012	20,000		$ 6.00	$ 8.50	(28)
Natural Gas Three-way Collars	**(in MMBtus)**		**(per MMBtu)**		
First Quarter 2010	30,000	$6.83	$ 9.50	$13.60	6,914
Natural Gas Swaps	**(in MMBtus)**		**(per MMBtu)**		
First Quarter 2010	15,000		$ 6.19		733
Second Quarter 2010	30,000		$ 6.17		1,648
Third Quarter 2010	30,000		$ 6.17		1,122
Crude Oil Costless Collars	**(barrels)**		**(per barrel)**		
First Quarter 2010	500		$60.00	$74.75	(308)
Second Quarter 2010	500		$60.00	$74.75	(455)
Third Quarter 2010	500		$60.00	$74.75	(546)
Fourth Quarter 2010	500		$60.00	$74.75	(608)
Settlements to be received in subsequent period					226

We estimate that a $1.00 per MMBtu increase in the natural gas purchase price would decrease the fair value of the natural gas derivatives by $22.4 million. We estimate that a $1.00 per MMBtu decrease in the natural gas purchase price would increase the fair value for the natural gas derivatives by $22.9 million. In addition, we estimate that a $5.00 per barrel increase in the crude oil price would decrease the fair value of our crude oil derivatives by $0.8 million. We estimate that a $5.00 per barrel decrease in the crude oil price would increase the fair value of our crude oil derivatives by $0.7 million.

We estimate that, excluding the derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, oil and gas segment operating income for 2010 would increase or decrease by approximately $17.8 million. In addition, we estimate that for every $5.00 per barrel increase or decrease in the crude oil price, oil and gas segment operating income for 2010 would increase or decrease by approximately $1.8 million. This assumes that crude oil prices, natural gas prices and production volumes remain constant at anticipated levels. These estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

PVR Natural Gas Midstream Segment

The following table lists PVR's open mark-to-market commodity derivative agreements and their fair values as of December 31, 2009:

	Average Volume Per Day	Weighted Average Price			Fair Value
		Swap Price	Floor	Ceiling	
Crude Oil Collar	**(barrels)**		**($ per barrel)**		
First through Fourth Quarter 2010	750		$70.00	$81.25	$(1,329)
First through Fourth Quarter 2010	1,000		$68.00	$80.00	(2,171)
First through Fourth Quarter 2011	400		$75.00	$98.50	18
Natural Gas Purchase Swap	**(MMBtus)**	**($ per MMBtu)**			
First through Fourth Quarter 2010	5,000	5.815			(41)
First through Fourth Quarter 2011	3,000	6.430			(99)
NGL – Natural Gasoline Collar	**(gallons)**		**($ per gallon)**		
First through Fourth Quarter 2011	60,000		$ 1.55	$ 1.92	(945)
Settlements to be received in subsequent period					1,331

PVR estimates that a $5.00 per barrel increase in the crude oil price would decrease the fair value of its crude oil collars by $3.1 million. PVR estimates that a $5.00 per barrel decrease in the crude oil price would increase the fair value of its crude oil collars by $2.8 million. PVR estimates that a $1.00 per MMBtu increase in the natural gas price would increase the fair value of its natural gas purchase swaps by $2.7 million. PVR estimates that a $1.00 per MMBtu decrease in the natural gas price would decrease the fair value of its natural gas purchase swaps by $2.7 million. PVR estimates that a $0.11 per gallon increase in the natural gasoline (a natural gas liquid, NGL) price would decrease the fair value of its natural gasoline collar by $1.8 million. PVR estimates that a $0.11 per gallon decrease in the natural gasoline price would increase the fair value of its natural gasoline collar by $1.7 million.

PVR estimates that, excluding the effects of derivative positions described above, for every $1.00 per MMBtu increase or decrease in the natural gas price, its natural gas midstream gross margin and operating income for 2010 would increase or decrease by $6.9 million. In addition, we estimate that for every $5.00 per barrel increase or decrease in the crude oil price, our natural gas midstream gross margin and operating income in 2010 would increase or decrease by $11.5 million. This assumes that natural gas prices, crude oil prices and inlet volumes remain constant at anticipated levels. These estimated changes in PVR's gross margin and operating income exclude potential cash receipts or payments in settling these derivative positions.

Interest Rate Risk

As of December 31, 2009, PVR had $620.1 million of outstanding indebtedness under the PVR Revolver, which carries a variable interest rate throughout its term. PVR entered into the PVR Interest Rate Swaps to establish fixed interest rates on a portion of the outstanding indebtedness under the PVR Revolver. Until March 2010, the notional amounts of the PVR Interest Rate Swaps total $310.0 million, or 50%, of PVR's outstanding indebtedness under the PVR Revolver as of December 31, 2009, with PVR paying a weighted average fixed rate of 3.54% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, the notional amounts of the PVR Interest Rate Swaps total $250.0 million, or 40.3% of PVR's outstanding indebtedness under the PVR Revolver as of December 31, 2009, with PVR paying a weighted average fixed rate of 3.37% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From December 2011 to December 2012, the notional amounts of the PVR Interest Rate Swaps total $100.0 million, or 16.1% of PVR's outstanding indebtedness under the PVR Revolver as of December 31, 2009, with PVR paying a weighted average fixed rate of 2.09% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The PVR Interest Rate Swaps extend one year past the maturity of the current PVR Revolver. A 1% increase in short-term interest rates on the floating rate debt outstanding under the PVR Revolver (net of amounts fixed through the PVR Interest Rate Swaps) as of December 31, 2009 would cost PVR approximately $3.1 million in additional interest expense per year.

During the first quarter of 2009, both we and PVR discontinued hedge accounting for all of the Previous Interest Rate Swaps and the PVR Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Previous and New Interest Rate Swaps are recognized in earnings currently. Therefore, our results of operations are affected by the volatility of changes in fair value, which fluctuates with changes in interest rates. These fluctuations could be significant. See Note 8 to the Consolidated Financial Statements for a further description of our and PVR's derivatives program.

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Penn Virginia Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 1, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Item 9A(b) herein). Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated March 1, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
March 1, 2010

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31,		
	2009	2008	2007
Revenues			
Natural gas	$ 169,666	$ 368,801	$262,169
Crude oil	43,258	46,529	22,439
Natural gas liquids (NGLs)	15,735	21,292	5,678
Natural gas midstream	428,016	589,783	433,174
Coal royalties	120,435	122,834	94,140
Gain on sale of property and equipment	2,345	31,426	12,416
Other	35,682	40,186	22,934
Total revenues	815,137	1,220,851	852,950
Expenses			
Cost of midstream gas purchased	333,854	484,621	343,293
Operating	86,766	89,891	67,610
Exploration	57,754	42,436	28,608
Taxes other than income	22,073	28,586	21,723
General and administrative	80,000	74,494	66,983
Depreciation, depletion and amortization	223,367	192,236	129,523
Impairments	107,926	51,764	2,586
Loss on sale of assets	1,599	—	—
Total expenses	913,339	964,028	660,326
Operating income (loss)	(98,202)	256,823	192,624
Other income (expense)			
Interest expense	(68,884)	(49,299)	(37,851)
Derivatives	11,854	46,582	(47,282)
Other	2,612	(666)	3,651
Income (loss) before income taxes and noncontrolling interests	(152,620)	253,440	111,142
Income tax benefit (expense)	75,252	(71,920)	(30,332)
Net income (loss)	(77,368)	181,520	80,810
Less net income attributable to noncontrolling interests	(37,275)	(60,436)	(30,319)
Income (loss) attributable to Penn Virginia Corporation	$(114,643)	$ 121,084	$ 50,491
Earnings (loss) per share – basic and diluted:			
Earnings (loss) per share attributable to Penn Virginia Corporation			
Basic	$ (2.62)	$ 2.89	$ 1.32
Diluted	$ (2.62)	$ 2.87	$ 1.31
Weighted average shares outstanding, basic	43,811	41,760	38,061
Weighted average shares outstanding, diluted	43,811	42,031	38,358

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31, 2009	As of December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 98,331	$ 18,338
Accounts receivable, net of allowance for doubtful accounts	124,804	149,241
Derivative assets	17,572	67,569
Inventory	12,204	18,468
Assets held for sale	38,282	—
Other current assets	8,049	9,902
Total current assets	299,242	263,518
Property and equipment		
Oil and gas properties (successful efforts method)	1,960,140	2,107,128
Other property and equipment	1,146,973	1,076,471
Total property and equipment	3,107,113	3,183,599
Accumulated depreciation, depletion and amortization	(754,755)	(671,422)
Net property and equipment	2,352,358	2,512,177
Equity investments	87,601	78,443
Intangibles, net	83,741	92,672
Derivative assets	3,630	4,070
Other assets	61,935	45,685
Total assets	$2,888,507	$2,996,565
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 7,542
Accounts payable and accrued liabilities	137,388	206,902
Derivative liabilities	16,147	15,534
Deferred taxes	—	17,598
Income taxes payable	—	18
Total current liabilities	153,535	247,594
Other liabilities	43,463	45,887
Derivative liabilities	6,745	8,721
Deferred income taxes	328,238	371,925
Long-term debt of the Company	498,427	531,896
Long-term debt of PVR	620,100	568,100
Commitments and contingencies (Note 15)	—	—
Shareholders' equity:		
Preferred Stock of $100 par value – 100,000 shares authorized; none issued		
Common stock of $0.01 par value – 64,000,000 shares authorized; shares issued and outstanding of 45,386,004 and 41,870,893 as of December 31, 2009 and 2008, respectively	265	230
Paid-in capital	590,846	485,967
Retained earnings	319,167	443,646
Deferred compensation obligation	2,423	2,237
Accumulated other comprehensive loss	(1,286)	(4,182)
Treasury stock – 113,858 and 85,227 shares common stock, at cost, as of December 31, 2009 and 2008, respectively	(3,327)	(2,683)
Total Penn Virginia Corporation shareholders' equity	908,088	925,215
Noncontrolling interests of subsidiaries	329,911	297,227
Total shareholders' equity	1,237,999	1,222,442
Total liabilities and shareholders' equity	$2,888,507	$2,996,565

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities			
Net income (loss)	$ (77,368)	$ 181,520	$ 80,810
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	223,367	192,236	129,523
Impairments	107,926	51,764	2,586
Derivative contracts:			
Total derivative losses (gains)	(5,333)	(41,102)	52,157
Cash receipts (payments) to settle derivatives	61,147	(46,086)	(3,651)
Deferred income taxes	(83,222)	58,551	23,171
Loss (gain) on the sale of property and equipment	(1,910)	(31,426)	(12,416)
Dry hole and unproved leasehold expense	33,278	35,847	24,975
Other	22,632	12,522	5,393
Changes in operating assets and liabilities:			
Accounts receivable	24,879	29,418	(41,772)
Inventory	1,919	(13,440)	(1,106)
Accounts payable and accrued liabilities	(15,452)	(31,969)	42,733
Other assets and liabilities	(15,916)	(14,061)	10,627
Net cash provided by operating activities	275,947	383,774	313,030
Cash flows from investing activities			
Acquisitions	(46,894)	(293,747)	(292,001)
Additions to property and equipment	(239,459)	(585,339)	(421,509)
Other	16,241	33,519	30,027
Net cash used in investing activities	(270,112)	(845,567)	(683,483)
Cash flows from financing activities			
Dividends paid	(9,836)	(9,398)	(8,499)
Distributions paid to noncontrolling interest holders	(78,171)	(64,245)	(49,739)
Proceeds from (repayments) of bank borrowings	(7,542)	7,542	—
Proceeds from Company borrowings	87,000	273,000	283,500
Repayments of Company borrowings	(419,000)	(63,000)	(382,500)
Proceeds from PVR borrowings	132,000	453,800	220,500
Repayments of PVR borrowings	(80,000)	(297,800)	(27,000)
Net proceeds from issuance of Senior notes	291,009	—	—
Proceeds from the issuance of convertible notes	—	—	230,000
Net proceeds from the issuance of common stock	64,835	—	135,441
Cash received for stock warrants sold	—	—	18,187
Cash paid for convertible note hedges	—	—	(36,817)
Net proceeds from the issuance of PVR units	—	138,141	860
Net proceeds from the sale of PVG units	118,080	—	—
Debt issuance costs paid	(24,217)	(4,200)	(8,141)
Other	—	11,764	8,850
Net cash provided by financing activities	74,158	445,604	384,642
Net increase (decrease) in cash and cash equivalents	79,993	(16,189)	14,189
Cash and cash equivalents – beginning of period	18,338	34,527	20,338
Cash and cash equivalents – end of period	$ 98,331	$ 18,338	$ 34,527
Supplemental disclosures:			
Cash paid for:			
Interest (net of amounts capitalized)	$ 59,911	$ 43,244	$ 34,794
Income taxes (net of refunds received)	$ 9,443	$ 15,228	$ (1,897)
Noncash investing activities:			
Issuance of PVR units for acquisition	$ —	$ 15,171	$ —
PVG units given as consideration for acquisition	$ —	$ 68,021	$ —
Other liabilities	$ —	$ 4,673	$ —

See accompanying notes to consolidated financial statements.

SPENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(in thousands)

	Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Obligation	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Penn Virginia Stockholders' Equity	Noncontrolling Interests	Total Shareholders' Equity	Comprehensive Income (Loss)
Balance at December 31, 2006	$37,562	$188	$ 95,611	$ 289,967	$1,314	$(2,409)	$(1,649)	$ 383,022	$ 432,827	$ 815,849	$120,127
Dividends paid ($0.225 per share)	—	—	—	(8,498)	—	—	—	(8,498)	—	(8,498)	
Distributions to noncontrolling interest holders	—	—	—	—	—	—	—	—	(49,739)	(49,739)	
Issuance of common stock	3,450	35	135,371	—	—	—	—	135,406	—	135,406	
Purchase of call options, net of tax benefit of $14,580	—	—	(22,237)	—	—	—	—	(22,237)	—	(22,237)	
Sale of warrants	—	—	18,187	—	—	—	—	18,187	—	18,187	
Issuance costs attributable to convertible notes	—	—	21,216	—	—	—	—	21,216	—	21,216	
Sale of PVG units	—	—	(995)	—	—	—	—	(995)	—	(995)	
Recognition of SAB 51 gain (Note 3)	—	—	148,184	—	—	—	—	148,184	(241,736)	(93,552)	
Common stock issued as compensation	19	—	878	—	—	—	—	878	—	878	
PVR units issued as compensation	—	—	1,583	—	—	—	—	1,583	32	1,615	
Vesting of restricted units	—	—	(1,099)	—	—	—	—	(1,099)	1,099	—	
Exercise of stock options	366	2	8,791	—	—	—	—	8,793	—	8,793	
Compensation costs related to stock options	—	—	2,611	—	—	—	—	2,611	—	2,611	
Deferred compensation	11	—	613	—	294	—	(371)	536	—	536	
Other	—	—	—	—	—	—	—	—	815	815	
Net income	—	—	—	50,491	—	—	—	50,491	30,319	80,810	$ 80,810
Other comprehensive gain, net of tax	—	—	—	—	—	(785)	—	(785)	803	18	18
Balance at December 31, 2007	41,408	225	408,714	331,960	1,608	(3,194)	(2,020)	737,293	174,420	911,713	$ 80,828
Dividends paid ($0.225 per share)	—	—	—	(9,398)	—	—	—	(9,398)	—	(9,398)	
Distributions to noncontrolling interest holders	—	—	—	—	—	—	—	—	(64,245)	(64,245)	
Gain on sale of securities	—	—	(1,700)	—	—	—	—	(1,700)	—	(1,700)	
Recognition of SAB 51 gain (Note 3)	—	—	24,335	—	—	—	—	24,335	(39,723)	(15,388)	
Gain on sale of PVG units to PVR, net of tax (Note 4)	—	—	36,429	—	—	—	—	36,429	—	36,429	
PVG units transferred as acquisition consideration	—	—	—	—	—	—	—	—	23,469	23,469	
Public offering of PVR units	—	—	—	—	—	—	—	—	138,141	138,141	
Common stock issued as compensation	40	—	1,258	—	—	—	(663)	595	—	595	
PVR units issued as compensation	—	—	2,231	—	—	—	—	2,231	709	2,940	
Vesting of restricted units	—	—	(1,722)	—	—	—	—	(1,722)	1,722	—	
Exercise of stock options	423	5	11,722	—	—	—	—	11,727	—	11,727	
Compensation costs related to stock options	—	—	4,071	—	—	—	—	4,071	—	4,071	
Deferred compensation	—	—	629	—	629	—	—	1,258	—	1,258	
Net income	—	—	—	121,084	—	—	—	121,084	60,436	181,520	$181,520
Other comprehensive gain, net of tax	—	—	—	—	—	(988)	—	(988)	2,298	1,310	1,310
Balance at December 31, 2008	41,871	230	485,967	443,646	2,237	(4,182)	(2,683)	925,215	297,227	1,222,442	$182,830
Dividends paid ($0.225 per share)	—	—	—	(9,836)	—	—	—	(9,836)	—	(9,836)	
Distributions to noncontrolling interest holders	—	—	—	—	—	—	—	—	(78,171)	(78,171)	
Gain on sale of securities	—	—	(1,241)	—	—	—	—	(1,241)	—	(1,241)	
Issuance of common stock	3,500	35	64,800	—	—	—	—	64,835	—	64,835	
Sale of PVG units, net of taxes	—	—	32,739	—	—	—	—	32,739	67,713	100,452	
Common stock issued as compensation	3	—	60	—	—	—	—	60	—	60	
PVR units issued as compensation	—	—	2,190	—	—	—	—	2,190	1,796	3,986	
Vesting of restricted units	—	—	(3,023)	—	—	—	—	(3,023)	3,023	—	
Exercise of stock options	—	—	—	—	—	—	—	—	—	—	
Compensation costs related to stock options	—	—	6,602	—	—	—	—	6,602	—	6,602	
Deferred compensation	12	—	568	—	186	—	(258)	496	—	496	
Other	—	—	2,184	—	—	—	(386)	1,798	—	1,798	
Net income (loss)	—	—	—	(114,643)	—	—	—	(114,643)	37,275	(77,368)	$ (77,368)
Other comprehensive gain, net of tax	—	—	—	—	—	2,896	—	2,896	1,048	3,944	3,944
Balance at December 31, 2009	45,386	$265	$590,846	$ 319,167	$2,423	$(1,286)	$(3,327)	$ 908,088	$ 329,911	$1,237,999	$ (73,424)

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company primarily engaged in the development, exploration and production of natural gas and oil in various domestic onshore regions including East Texas, the Mid-Continent, Appalachia and Mississippi. We also indirectly own partner interests in Penn Virginia Resource Partners, L.P. ("PVR"), a publicly traded limited partnership formed by us in 2001. Our ownership interests in PVR are held principally through our general partner and 51.4% limited partner interests in Penn Virginia GP Holdings, L.P. ("PVG"), a publicly traded limited partnership formed by us in 2006. As of December 31, 2009, PVG owned an approximately 37% limited partner interest in PVR and 100% of the general partner of PVR, which holds a 2% general partner interest in PVR and all of the incentive distribution rights ("IDRs").

We are engaged in three primary business segments: (i) oil and gas, (ii) coal and natural resource management and (iii) natural gas midstream. We directly operate our oil and gas segment, and PVR operates our coal and natural resource management and natural gas midstream segments. Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's consolidated financial statements. Because we control the general partner of PVG, the financial results of PVG are included in our Consolidated Financial Statements. However, PVG and PVR function with capital structures that are independent of each other and us, with each having publicly traded common units and PVR having its own debt instruments. PVG does not currently have any debt instruments.

2. Penn Virginia Resource Partners, L.P. and Penn Virginia GP Holdings, L.P.

PVR is principally engaged in the management of coal and natural resource properties and the gathering and processing of natural gas in the United States. PVG derives its cash flow solely from cash distributions received from PVR. PVG's general partner is an indirect wholly owned subsidiary of ours.

PVR's coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. PVR's coal reserves are primarily located in Kentucky, Virginia, West Virginia, Illinois and New Mexico. PVR also earns revenues from other land management activities, such as selling standing timber, leasing fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants, collecting oil and gas royalties and from coal transportation, or wheelage, fees.

PVR's natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. PVR owns and operates natural gas midstream assets located in Oklahoma and Texas. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. In addition, PVR owns a 25% member interest in Thunder Creek Gas Services, LLC ("Thunder Creek"), a joint venture that gathers and transports coalbed methane ("CBM") in Wyoming's Powder River Basin. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines. PVR's natural gas marketing and gathering and processing businesses provide services to us for which we are charged agent fees. During 2009, 2008 and 2007, we paid a total of \$5.4 million, \$5.3 million and \$2.2 million in agent fees to PVR (see Note 24).

Cash flow available to us from PVG and PVR is only in the form of cash distributions declared and paid to us as a result of our partner interests in each of them. We received cash distributions of \$42.3 million, \$44.0 million and \$29.8 million from PVG and PVR in the years ended December 31, 2009, 2008 and 2007, as a result of our partner interests in PVG and PVR.

3. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries, including PVG and PVR. Intercompany balances and transactions have been eliminated. Investments in affiliated companies where we have a 20% to 50% ownership interest are accounted for using the equity method of accounting. These investments are presented separately on the Consolidated Balance Sheets and earnings from equity affiliates are recorded as other revenues on the Consolidated Statements of Income.

Use of Estimates

Preparation of our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for Doubtful Accounts

The allowance for doubtful accounts represents an estimate of uncollectible accounts receivable. The recorded amount reflects various factors, including accounts receivable aging, customer-specific risk issues and historical write-off experience. When a specific accounts receivable balance is deemed uncollectible, a charge is taken to this reserve. Recoveries of balances previously written off are also reflected in this reserve.

Inventories

Inventories, which primarily consist of tubular products, are stated at the lower of cost or market and are valued principally on the weighted-average-cost method.

Assets Held for Sale

When specific actions to dispose of assets progress to the point that "plan of sale" criteria have been met, impairments, to the extent they exist, are recognized in the Consolidated Statements of Income and the underlying assets are reclassified as assets held for sale. Gains and losses on sales of assets are reflected in total revenues or total expenses, respectively.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

3. Summary of Significant Accounting Policies – (continued)

The costs of unproved leaseholds, including associated interest costs for the period activities that were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Other Property and Equipment

Other property and equipment primarily consist of processing facilities, gathering systems, compressor stations, PVR's ownership in coal fee mineral interests, PVR's royalty interest in oil and natural gas wells, forestlands and related equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

We compute depreciation and amortization of property, plant and equipment using the straight-line balance method over the estimated useful life of each asset as follows:

	Useful Life
Gathering systems	15 – 20 years
Compressor stations	5 – 15 years
Processing plants	15 years
Other property and equipment	3 – 20 years

Coal properties are depleted on an area-by-area basis at a rate based on the cost of the mineral properties and the number of tons of estimated proven and probable coal reserves contained therein. Proven and probable coal reserves have been estimated by PVR's own geologists and outside consultants. PVR's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively. From time to time, PVR carries out core-hole drilling activities on its coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-hole drilling activities are expensed as incurred. PVR depletes timber using a methodology consistent with the units-of-production method, but that is based on the quantity of timber harvested. PVR determines depletion of oil and gas royalty interests by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. When PVR retires or sells an asset, we remove its cost and related accumulated depreciation and amortization from our Consolidated Balance Sheets. We record the difference between the net book value, net of any assumed asset retirement obligation ("ARO"), and proceeds from dispositions of property and equipment as a gain or loss.

Intangible Assets

Intangible assets are primarily associated with assumed contracts, customer relationships and rights-of-way. These intangible assets are amortized over periods of up to 20 years, the period in which benefits are derived from the contracts, relationships and rights-of-way.

3. Summary of Significant Accounting Policies – (continued)

Impairment of Long-Lived and Other Assets

We review assets for impairment when events or circumstances indicate a possible decline in the recoverability of the carrying value of such property. If the carrying value of the asset is determined to be impaired, we reduce the asset to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and could include estimates of future production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives on certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depletion and amortization ("DD&A") on the affected properties, which would decrease earnings or result in losses through higher DD&A. The revisions may also be sufficient enough to cause impairment losses on certain properties that would result in a further non-cash expense to earnings. If natural gas, crude oil and NGL prices decline or we drill uneconomic wells, it is reasonably possible we could have a significant impairment charge to be recorded in our Consolidated Statements of Income.

We review oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we classify impairments of long-lived assets as a level 3 fair value measure (see Notes 5 and 19).

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in a company's financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. We recognize interest related to unrecognized tax benefits in interest expense and penalties are included in income tax expense.

Asset Retirement Obligations

We recognize the fair value of a liability for an ARO in the period in which it is incurred. The determination of fair value is based upon regional market and specific facility type information. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. The long-lived assets for which our AROs are recorded include natural gas processing facilities, compressor stations, gathering systems, coal processing plants and oil and natural gas wells. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we categorized the initial fair value estimates as a level 3 input. After recording these amounts, the ARO is accreted to its future estimated value

3. Summary of Significant Accounting Policies – (continued)

using the same assumed rate, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion and the depreciation are included in DD&A expense on our Consolidated Statements of Income.

In connection with PVR's natural gas midstream assets, we are obligated under federal regulations to perform limited procedures around the abandonment of pipelines. In some cases, we are unable to reasonably determine the fair value of such ARO because the settlement dates, or ranges thereof, are indeterminable. An ARO will be recorded in the period in which we can reasonably determine the settlement dates.

Environmental Liabilities

Other liabilities include accruals for environmental liabilities that we either assumed in connection with certain acquisitions or recorded in operating expenses when it became probable that a liability had been incurred and the amount of that liability could be reasonably estimated.

Derivative Instruments

From time to time, we and PVR utilize derivative financial instruments to mitigate our exposure to interest rates, and natural gas, NGL and crude oil price volatility. The derivative financial instruments, which are placed with financial institutions that we believe are acceptable credit risks, take the form of swaps, collars and three-way collars. All derivative financial instruments are recognized in the Consolidated Financial Statements at fair value. The fair values of our and PVR's derivative instruments are determined based on discounted cash flows derived from quoted forward prices. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Because we and PVR no longer apply hedge accounting for our commodity derivatives, we recognize changes in fair value in earnings currently as a component of the derivatives line on the Consolidated Statements of Income. We and PVR have experienced and could continue to experience significant changes in the estimate of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts. The discontinuation of hedge accounting has no impact on our and PVR's reported cash flows, although our and PVR's results of operations are affected by the volatility of mark-to-market gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment.

Revenue Recognition

Oil and Gas Revenues. We record revenues associated with sales of natural gas, crude oil, condensate and NGLs when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers on the basis of our net working interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. We treat any amount received in excess of our share as deferred revenues. If we take less than we are entitled to take, we record the under-delivery as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by our partners. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

3. Summary of Significant Accounting Policies – (continued)

Natural Gas Midstream Revenues. We recognize revenues from the sale of NGLs and residue gas when PVR sells the NGLs and residue gas produced at its gas processing plants. We recognize gathering and transportation revenues based upon actual volumes delivered. Due to the time needed to gather information from various purchasers and measurement locations and then calculate volumes delivered, the collection of natural gas midstream revenues may take up to 30 days following the month of production. Therefore, we make accruals for revenues and accounts receivable and the related cost of midstream gas purchased and accounts payable based on estimates of natural gas purchased and NGLs and residue gas sold. We record any differences, which historically have not been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Coal Royalties Revenues. We recognize coal royalties revenues on the basis of tons of coal sold by PVR's lessees and the corresponding revenues from those sales. Since PVR does not operate any coal mines, it does not have access to actual production and revenues information until approximately 30 days following the month of production. Therefore, our financial results include estimated revenues and accounts receivable for the month of production. We record any differences, which historically have not been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Share-Based Compensation

We have several stock compensation plans that allow incentive and nonqualified stock options and restricted stock to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. The general partners of PVG and PVR both have long-term incentive plans that permit the granting of awards to their directors and employees and employees of their affiliates who perform services for PVG and PVR. We and PVR measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Concentration of Credit Risk

Approximately 17% of PVR's natural gas midstream segment accounts receivables and 9% of our consolidated accounts receivable at December 31, 2009 related to three natural gas midstream customers. Approximately $8.3 million of our oil and gas segment trade receivables at December 31, 2009 was related to one customer. Approximately 19% of our oil and gas segment's receivables and 7% of our consolidated receivables at December 31, 2009 related to this oil and gas customer. No significant uncertainties related to the collectability of amounts owed to us or PVR exists in regards to the natural gas midstream segment or oil and gas segment customers.

At December 31, 2009, we reported a commodity derivative asset related to our oil and gas segment of $14.5 million, over 50% of which was concentrated with one counterparty. This concentration may impact our overall credit risk, either positively or negatively, in that this counterparty may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties related to the collectability of amounts owed to us exist with regard to this counterparty.

These concentrations may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions.

New Accounting Standards

In January 2010, the Financial Accounting Standards Board (the "FASB") issued new authoritative guidance with respect oil and gas reserve estimation and disclosures. The new guidance effectively aligns the oil and gas reserve estimation and disclosure requirements of GAAP with the requirements of the Securities and Exchange Commission that were issued in the form of a final rule in December 2008. The new guidance is intended to provide investors with a more meaningful and comprehensive understanding of oil and gas

3. Summary of Significant Accounting Policies – (continued)

reserves by expanding the definition of proved oil and gas producing activities and updating the reserve estimation requirements for changes in practice and technology that have occurred during the past several decades. One of the more significant changes associated with the new guidance is the requirement to utilize an average (beginning of the month basis) oil and gas price for the year in the determination of estimates of future net revenues and the standardized measure. We applied the new guidance to our supplemental oil and gas producing activities disclosures as of December 31, 2009 included herein.

In August 2009, the FASB issued guidance on how companies should measure liabilities at fair value. The guidance clarifies that the quoted price for an identical liability should be used. However, if such information is not available, an entity may use the quoted price of an identical liability when traded as an asset, quoted prices for similar liabilities or similar liabilities traded as assets, or another valuation technique (such as the market or income approach). The guidance also indicates that the fair value of a liability is not adjusted to reflect the impact of contractual restrictions that prevent its transfer and indicates circumstances in which quoted prices for an identical liability or quoted price for an identical liability traded as an asset may be considered level 1 fair value measurements. This guidance was effective October 1, 2009 and the adoption did not have a material impact on our Consolidated Financial Statements.

In April 2009, the FASB issued an amendment to business combination standards related to accounting for assets acquired and liabilities assumed in a business combination that arise from contingencies. This amendment addresses application issues raised by preparers, auditors and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting and disclosure of assets and liabilities arising from contingencies in a business combination. The amendment is effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. This amendment will have an impact on our accounting for any future business combinations.

In April 2008, The FASB issued an amendment to accounting standards related to the determination of the useful life of intangible assets. This amendment addresses the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible. This amendment is effective for fiscal years beginning after December 15, 2008 and did not have a material impact on our Consolidated Financial Statements upon its adoption.

Effective January 1, 2009, we adopted the new accounting standard issued by the FASB on noncontrolling interest in consolidated financial statements. This standard requires that the noncontrolling interests in PVG and PVR be reported on our Consolidated Balance Sheets as a separate item within shareholders' equity. Net income attributable to the noncontrolling interest in PVG and PVR is separately presented on the face of our Consolidated Statement of Income. Our Consolidated Financial Statements have been adjusted on a retrospective basis to reflect the adoption of this standard. Comprehensive income attributable to the noncontrolling interests in PVG and PVR is separately presented in our schedule of comprehensive income. The standard also requires that gains from the sale of subsidiary units be recorded directly to shareholders equity. If, in the future, we sell sufficient controlling interests in our subsidiaries to require deconsolidation of those subsidiaries, then we expect to record a gain or loss on our Consolidated Statement of Income.

Subsequent Events

Management has evaluated all activities of the Company through, the date upon which the Consolidated Financial Statements were issued, and concluded that no subsequent events have occurred that would require recognition in the Consolidated Financial Statements or disclosure in the Notes to the Consolidated Financial Statements.

(in thousands, except per share amounts)

3. Summary of Significant Accounting Policies – (continued)

Prior-Period Revision

During the fourth quarter of 2009, we identified an accounting error related to deferred income taxes associated with certain subsidiary equity issuance transactions that were recorded in shareholders' equity from 2004 through 2008 in accordance with SEC Staff Accounting Bulletin No. 51 (or Topic 5-H), *Accounting for Sales of Stock by a Subsidiary* ("SAB 51"). We accounted for these equity issuances of PVR and PVG as sales of minority interests, now noncontrolling interests, upon the Company's adoption of the new accounting standard on noncontrolling interests in consolidated financial statements as of January 1, 2009. For each PVR or PVG equity issuance, we recognized a SAB 51 gain in shareholders' equity. Upon analysis of the 2009 sale of PVG units, management identified deferred income tax liabilities that should have been recorded in prior periods. The impact of this reclassification was an understatement of long-term deferred income tax liability, and an overstatement of paid-in capital for the years ended December 31, 2004 through 2008, including the related quarterly periods contained therein. The error had no effect on the statements of income or cash flows. The cumulative impact on the December 31, 2008, balance sheet would have been an increase in the deferred income tax liability of approximately $114 million with a corresponding decrease in paid-in capital. Management determined that the effects of the misstatement were not material to any previously reported quarterly or annual period; therefore, the related corrections were reflected in the 2008 and 2009 balance sheet and the 2007 portion of the statement of stockholders' equity. Prior period financial statements included in this filing have been revised to reflect these adjustments and the following table identifies those adjustments to deferred income taxes and additional paid-in capital resulting from the revision:

	2008	2007	2006
Cumulative revision as of December 31,			
Deferred income tax liabilities (noncurrent)	$ 113,888	$ 98,513	$ 4,949
Additional paid-in capital	(113,888)	(98,513)	(4,949)
Revision for the year ended December 31,			
Deferred income tax liabilities (noncurrent)	15,375	93,564	—
Additional paid-in capital	(15,375)	(93,564)	—

4. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

Fair value measurements are to be classified and disclosed in one of the following three categories:

- *Level 1:* Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- *Level 2:* Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

(in thousands, except per share amounts)

4. Fair Value Measurements – (continued)

- *Level 3:* Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Recurring Fair Value Measurements

Certain assets and liabilities are measured at fair value on a recurring basis in our Consolidated Balance Sheet. The following table summarizes the valuation of our assets and liabilities for the periods presented:

	As of December 31, 2009			
		Fair Value Measurement Classification		
Description	Fair Value Measurement	Level 1	Level 2	Level 3
Assets:				
Publicly traded equity securities	$ 5,904	$ 5,904	$ —	$—
Interest rate swap assets – current	1,463	—	1,463	—
Interest rate swap assets – noncurrent	1,266	—	1,266	—
Commodity derivative assets – current	16,109	—	16,109	—
Commodity derivative assets – noncurrent	2,364	—	2,364	—
Liabilities:				
Deferred compensation – noncurrent liability	(6,564)	(6,564)	—	—
Interest rate swap liabilities – current	(10,123)	—	(10,123)	—
Interest rate swap liabilities – noncurrent	(5,575)	—	(5,575)	—
Commodity derivative liabilities – current	(6,024)	—	(6,024)	—
Commodity derivative liabilities – noncurrent	(1,170)	—	(1,170)	—
Totals	$ (2,350)	$ (660)	$ (1,690)	$—

	As of December 31, 2008			
		Fair Value Measurement Classification		
Description	Fair Value Measurement	Level 1	Level 2	Level 3
Assets:				
Publicly traded equity securities	$ 4,559	$ 4,559	$ —	$—
Commodity derivative assets – current	67,569	—	67,569	—
Commodity derivative assets – noncurrent	4,070	—	4,070	—
Liabilities:				
Deferred compensation – noncurrent liability	(5,056)	(5,056)	—	—
Interest rate swap liabilities – current	(7,840)	—	(7,840)	—
Interest rate swap liabilities – noncurrent	(8,721)	—	(8,721)	—
Commodity derivative liabilities – current	(7,694)	—	(7,694)	—
Totals	$46,887	$ (497)	$47,384	$—

4. Fair Value Measurements – (continued)

We used the following methods and assumptions to estimate the fair values:

- *Cash, cash equivalents, accounts receivable and accounts payable*: The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.
- *Publicly traded equity securities*: Our publicly traded equity securities consist of various publicly traded equities that are held as assets for funding certain deferred compensation obligations. The fair values are based on quoted market prices, which are level 1 inputs.
- *Commodity derivatives*: Both our oil and gas commodity derivatives and the PVR natural gas midstream segment's commodity derivatives utilize swaps and collar derivative contracts. PVR also utilizes collar derivative contracts to hedge against the variability in its frac spread. We determine the fair values of our oil and gas derivative agreements based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of December 31, 2009, respectively. PVR determines the fair values of its commodity derivative agreements based on discounted cash flows based on quoted forward prices for the respective commodities. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input. See Note 8 for the effects of the derivative instruments on our Consolidated Statements of Income.
- *Interest rate swaps*: In 2009, we entered into interest rate swap agreements to establish variable rates on a portion of the outstanding obligations under the Senior Notes. In prior years, we entered into interest rate swap agreements to establish fixed rates on a portion of the outstanding borrowings under the Revolver. PVR has entered into interest rate swap agreements to establish fixed rates on a portion of the outstanding borrowings under the PVR Revolver. We use an income approach using valuation techniques that connect future cash flows to a single discounted value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a level 2 input.
- *Deferred compensation*: Certain of our deferred compensation obligations are ultimately to be settled in cash based on the underlying fair value of certain publicly traded equity securities. The fair values of these obligations are based on quoted market prices, which are level 1 inputs.

Additional Fair Value Disclosures

The fair value of floating-rate debt approximates the carrying amount because the interest rates paid are based on short-term maturities. The fair value of our fixed rate long-term debt is estimated based on the published market prices for the same or similar issues. As of December 31, 2009 and 2008, the fair value of our fixed rate debt was $545.7 million and $168.5 million, respectively.

5. Acquisitions and Divestitures

In the following paragraphs, all references to coal, crude oil and natural gas reserves and acreage acquired are unaudited. The factors we used to determine the fair market value of acquisitions include, but are not limited to, discounted future net cash flows on a risked-adjusted basis, geographic location, quality of resources, potential marketability and financial condition of lessees.

(in thousands, except per share amounts)

5. Acquisitions and Divestitures – (continued)

Business Combination

Lone Star Gathering, L.P. ("Lone Star")

On July 17, 2008, PVR completed an acquisition of substantially all of the assets of Lone Star. Lone Star's assets are located in the southern portion of the Fort Worth Basin of North Texas and include approximately 129 miles of gas gathering pipelines and approximately 240,000 acres dedicated by active producers. The Lone Star acquisition expanded the geographic scope of the PVR natural gas midstream segment into the Barnett Shale play in the Fort Worth Basin.

PVR acquired this business for approximately $164.3 million and a liability of $4.7 million, which represents the fair value of a $5 million guaranteed payment, plus contingent payments of $30 million and $25 million. Funding for the acquisition was provided by $80.7 million of borrowings under PVR's revolving credit facility (the "PVR Revolver"), 2,009,995 of PVG common units (which PVR purchased from two subsidiaries of ours for $61.8 million) and 542,610 newly issued PVR common units.

The contingent payments will be triggered if revenues from certain assets located in a defined geographic area reach certain targets by or before June 30, 2013 and will be funded in cash or common units, at PVR's election.

The Lone Star acquisition has been accounted for using the purchase method of accounting. Under the purchase method of accounting, the total purchase price has been allocated to the net tangible and intangible assets acquired from Lone Star based on their estimated fair values. The total purchase price was allocated to the assets purchased based upon fair values on the date of the Lone Star acquisition as follows:

Cash consideration paid for Lone Star	$ 81,125
Fair value of PVG common units given as consideration for Lone Star	68,021
Fair value of PVR common units issued and given as consideration for Lone Star	15,171
Fair value of payment guaranteed December 31, 2009	4,673
Total purchase price	$168,990
Fair value of assets acquired:	
Property and equipment	$ 88,596
Intangible assets	69,200
Goodwill	11,194
Fair value of assets acquired	$168,990

The goodwill and intangible assets acquired were allocated to the PVR natural gas midstream segment. A significant factor that contributed to the initial recognition of goodwill was the ability to acquire an established business on the western border of the expanding Barnett Shale play in the Fort Worth Basin. However, as a result of testing goodwill for impairment in the fourth quarter of 2008, we subsequently recognized a loss on the full impairment of the goodwill.

The intangible assets are associated with certain assumed contracts and customer relationships. These intangible assets are being amortized over the period in which benefits are derived from the contracts and relationships assumed and will be reviewed for impairment. Based on when the estimated economic benefit will be earned, we have estimated the useful lives of these intangible assets to be 20 years (see Note 11).

(in thousands, except per share amounts)

5. Acquisitions and Divestitures – (continued)

The following pro forma financial information reflects the consolidated results of our operations as if the Lone Star acquisition had occurred on January 1, 2007. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, the amortization of intangible assets, interest expense for acquisition debt and the change in weighted average common units resulting from the issuance of 542,610 PVR common units given as consideration in the Lone Star acquisition. The pro forma financial information is not necessarily indicative of the results of operations as it would have been had these transactions been effected on the assumed date:

	(Unaudited) Year Ended December 31,	
	2008	2007
Revenues	$1,224,418	$855,944
Net income attributable to Penn Virginia Corporation	$ 118,449	$ 46,753
Net income per share, basic	$ 2.84	$ 1.23
Net income per share, diluted	$ 2.81	$ 1.21

Other Business Combinations

In July 2009, PVR completed an acquisition of the gas processing and residue pipeline facilities in western Oklahoma for approximately $22.6 million in cash (the "Sweetwater" plant). Funding of the acquisition was provided by long-term debt under the PVR Revolver. The acquired assets included a 60 MMcfd processing plant. The purchase price has been allocated as follows: $13.1 million to processing plant and related equipment and $9.5 million to pipelines and compressor stations. The acquisition included nonfinancial assets and liabilities that were measured at fair value. The cost approach was used to develop the fair values of the acquisition. The cost approach is a technique that uses the reproduction or replacement cost as an initial basis for value. The cost to reproduce or replace the subject asset with a new asset, either identical (reproduction) or having the same utility (replacement), establishes the highest amount a prudent investor is likely to pay. Because these significant fair value inputs are typically not observable, we categorized the initial fair value estimates as a Level 3 input.

In April 2008, PVR acquired a 25% member interest in Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin. The purchase price was $51.6 million in cash, after customary closing adjustments and was funded with long-term debt under the PVR Revolver. The entire member interest is recorded in equity investments on the Consolidated Balance Sheets. This investment includes $37.3 million of fair value for the net assets acquired and $14.3 million of fair value paid in excess of PVR's portion of the underlying equity in the net assets acquired related to customer contracts and related customer relations. This excess is being amortized to equity earnings over the life of the underlying contracts, which is 12 years. The earnings are recorded in other revenues on our Consolidated Statements of Income.

In October 2007, we acquired lease rights to property covering 4,800 acres located in East Texas, with estimated proved reserves of 21.9 Bcfe. The purchase price was $44.9 million in cash and was funded with long-term debt under the revolving credit facility (the "Revolver").

In September 2007, PVR acquired fee ownership of approximately 62,000 acres of forestland in northern West Virginia. The purchase price was $93.3 million in cash and was funded with long-term debt under the PVR Revolver. The purchase price has been allocated as follows: $86.1 million to timber, $6.6 million to land and $0.6 million to oil and gas royalty interests.

In August 2007, we acquired the lease rights to property covering approximately 22,700 acres located in eastern Oklahoma with estimated proved reserves of 18.8 Bcfe. The purchase price was $47.9 million in cash and was funded with long-term debt under the Revolver. We acquired these assets in order to expand our oil and gas segment business. The acquisition has been recorded as a component of oil and gas properties.

(in thousands, except per share amounts)

5. Acquisitions and Divestitures – (continued)

In June 2007, PVR acquired a combination of fee ownership and lease rights to approximately 51 million tons of coal reserves, along with a preparation plant and coal handling facilities. The property is located on approximately 17,000 acres in western Kentucky. The purchase price was $42 million in cash and was funded with long-term debt under the PVR Revolver. The purchase price has been allocated as follows: $30.2 million to coal properties, $11.3 million to the coal processing plant and related facilities and $0.5 million to land. PVR also recorded a $28.1 million lease receivable and $16.6 million to deferred rent relating to a coal services facility lease.

The pro forma results for the years ended December 31, 2008 and 2007 for the above acquisitions did not materially change the historical results for those periods.

Divestitures

On December 23, 2009, we entered into purchase and sale agreements with Hilcorp Energy I, L.P. ("Hilcorp") which resulted in the transfer of all of our oil and gas properties in the Gulf Coast region (southern Texas and Louisiana) in exchange for net cash proceeds of $32 million and oil and gas properties located in the Gwinville field in northern Mississippi, excluding transaction costs and purchase and sale adjustments. The fair value of the properties received from Hilcorp was $8.2 million. An initial deposit of $2.3 million was received from Hilcorp in December 2009. This amount is reflected in accrued liabilities as of December 31, 2009. The transaction provided for certain purchase and sale adjustments based upon the collection of revenues and the payment of expenses attributable to the properties that took place after an effective date of October 1, 2009 and prior to the closing which occurred on January 29, 2010. During 2009, we recorded an impairment of $97.4 million on the Gulf Coast properties. Upon the closing of the transaction in January 2010, we received total net proceeds of $23.2 million plus the aforementioned Mississippi oil and gas properties valued at $8.2 million, reflecting all actual purchase and sale adjustments prior to the closing.

During the fourth quarter of 2009, we also committed to the disposition of certain oil and gas properties in North Dakota. The fair value of these properties was $2.6 million as of December 31, 2009, which we expect to realize during 2010. During 2009, we recorded an impairment of $3.7 million on the North Dakota properties.

The combined fair value of the Gulf Coast and North Dakota oil and gas properties, as well as liabilities attributable to the disposal groups, have been reflected as assets and liabilities held for sale and included in current assets and current liabilities, respectively, as of December 31, 2009. As of December 31, 2009, the fair value of the disposal group, consisting of the underlying properties and related assets and liabilities, was derived using a market approach based on agreements of sale for our Gulf Coast properties and indications of interest from potential third-party purchasers of the North Dakota properties, adjusted for working capital and closing costs. Because these significant fair value inputs are typically not observable, we have categorized the amounts as Level 3 inputs.

The following table reflects the fair values on our balance sheet as of December 31, 2009:

Assets held for sale	
Fair value of oil and gas properties	$38,282
Liabilities held for sale	
Asset retirement obligation	$ 500

In July 2008, we sold certain unproved oil and gas acreage in Louisiana for cash proceeds of $32 million and recognized a $30.5 million gain on that sale. The $30.5 million gain on the sale is reported in the revenues section of our Consolidated Statements of Income.

(in thousands, except per share amounts)

5. Acquisitions and Divestitures – (continued)

In September 2007, we sold non-operated working interests in oil and gas properties located in eastern Kentucky and southwestern Virginia, with estimated proved reserves of 13.3 Bcfe. The sale price was $29.1 million in cash, and the proceeds of the sale were used to repay borrowings under the Revolver. We recognized a gain of $12.4 million on the sale, which is reported in the revenues section of our Consolidated Statements of Income.

6. Accounts Receivable, net

The following table summarizes our accounts receivable by operating segment:

	As of December 31,	
	2009	2008
Penn Virginia oil and gas	$ 44,178	$ 76,981
PVR natural gas midstream	69,865	59,384
PVR coal and natural resource management	13,021	15,235
Other non-trade	107	18
	127,171	151,618
Less: Allowance for doubtful accounts	(2,367)	(2,377)
	$124,804	$149,241

As of December 31, 2009, no receivables were collateralized.

7. Inventories

The following table summarizes the components of our inventories:

	As of December 31,	
	2009	2008
Tubular products and well equipment	$10,372	$16,595
Other equipment and supplies	1,832	1,873
	$12,204	$18,468

During 2009, we experienced a market decline in value related to a re-evaluation of our tubular products inventory resulting in an impairment of $4.1 million. The impairment charge was included in the impairments line of our Consolidated Statements of Income.

8. Derivative Financial Instruments

Oil and Gas Segment Commodity Derivatives

We utilize collars and swap derivative contracts to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

A three-way collar contract consists of a collar contract plus a put option contract sold by us with a price below the floor price of the collar. The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract.

(in thousands, except per share amounts)

8. Derivative Financial Instruments – (continued)

The additional put option sold by us requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put option price. By combining the collar contract with the additional put option, we are entitled to a net payment equal to the difference between the floor price of the collar contract and the additional put option price if the settlement price is equal to or less than the additional put option price. If the settlement price is greater than the additional put option price, the result is the same as it would have been with a collar contract only. If market prices are below the additional put option, we would be entitled to receive the market price plus the difference between the additional put option and the floor. This strategy enables us to increase the floor and the ceiling prices of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option.

We determine the fair values of our oil and gas derivative agreements using third-party quoted forward prices for NYMEX Henry Hub natural gas and West Texas Intermediate crude oil closing prices as of December 31, 2009 and discount rates adjusted for the credit risk of our counterparties if the derivative in an asset position, and our own credit risk if the derivative is in a liability position.

The following table sets forth our commodity derivative positions as of December 31, 2009:

	Average Volume Per Day	Weighted Average Price			Fair Value
		Additional Put Option	Floor	Ceiling	
Natural Gas Costless Collars	**(in MMBtu)**		**(per MMBtu)**		
First Quarter 2010	35,000		$ 4.96	$ 7.41	$ 115
Second Quarter 2010	30,000		$ 5.33	$ 8.02	1,047
Third Quarter 2010	30,000		$ 5.33	$ 8.02	883
Fourth Quarter 2010	50,000		$ 5.65	$ 8.77	1,656
First Quarter 2011	50,000		$ 5.65	$ 8.77	307
Second Quarter 2011	30,000		$ 5.67	$ 7.58	787
Third Quarter 2011	30,000		$ 5.67	$ 7.58	553
Fourth Quarter 2011	20,000		$ 6.00	$ 8.50	469
First Quarter 2012	20,000		$ 6.00	$ 8.50	(28)
Natural Gas Three-way Collars	**(in MMBtu)**		**(per MMBtu)**		
First Quarter 2010	30,000	$6.83	$ 9.50	$13.60	6,914
Natural Gas Swaps	**(in MMBtu)**		**(per MMBtu)**		
First Quarter 2010	15,000		$ 6.19		733
Second Quarter 2010	30,000		$ 6.17		1,648
Third Quarter 2010	30,000		$ 6.17		1,122
Crude Oil Costless Collars	**(barrels)**		**(per barrel)**		
First Quarter 2010	500		$60.00	$74.75	(308)
Second Quarter 2010	500		$60.00	$74.75	(455)
Third Quarter 2010	500		$60.00	$74.75	(546)
Fourth Quarter 2010	500		$60.00	$74.75	(608)
Settlements to be received in subsequent period					226

(in thousands, except per share amounts)

8. Derivative Financial Instruments – (continued)

PVR Natural Gas Midstream Segment Commodity Derivatives

PVR utilizes costless collars and swap derivative contracts to hedge against the variability in cash flows associated with anticipated natural gas midstream revenues and cost of midstream gas purchased. PVR also utilizes collar derivative contracts to hedge against the variability in its frac spread. PVR's frac spread is the spread between the purchase price for the natural gas it purchases from producers and the sale price for NGLs that it sells after processing. PVR hedges against the variability in its frac spread by entering into costless collar and swap derivative contracts to sell NGLs forward at a predetermined commodity price and to purchase an equivalent volume of natural gas forward on an MMBtu basis. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues or cost savings from favorable price movements.

With respect to a costless collar contract, the counterparty is required to make a payment to PVR if the settlement price for any settlement period is below the Put (or floor) price for such contract. PVR is required to make a payment to the counterparty if the settlement price for any settlement period is above the Call (or ceiling) price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. With respect to a swap contract for the purchase of a commodity, the counterparty is required to make a payment to PVR if the settlement price for any settlement period is greater than the swap price for such contract, and PVR is required to make a payment to the counterparty if the settlement price is less than the swap price for such contract.

PVR determines the fair values of its derivative agreements by discounting the cash flows based on quoted forward prices for the respective commodities as of December 31, 2009, using discount rates adjusted for the credit risk of the counterparties if the derivative is in an asset position and PVR's own credit risk for derivatives in a liability position.

The following table sets forth PVR's positions as of December 31, 2009 for commodities related to natural gas midstream revenues and cost of midstream gas purchased:

	Average Volume Per Day	Swap Price	Weighted Average Price		Fair Value
			Floor	Ceiling	
Crude Oil Collar	**(barrels)**		**($ per barrel)**		
First through Fourth Quarter 2010	750		$70.00	$81.25	$(1,329)
First through Fourth Quarter 2010	1,000		$68.00	$80.00	(2,171)
First through Fourth Quarter 2011	400		$75.00	$98.50	18
Natural Gas Purchase Swap	**(MMBtu)**	**($ per MMBtu)**			
First through Fourth Quarter 2010	5,000	5.815			(41)
First through Fourth Quarter 2011	3,000	6.430			(99)
NGL – Natural Gasoline Collar	**(gallons)**		**($ per gallon)**		
First through Fourth Quarter 2011	60,000		$ 1.55	$ 1.92	(945)
Settlements to be received in subsequent period					1,331

8. Derivative Financial Instruments – (continued)

Interest Rate Swaps

In 2006, we entered into interest rate swaps ("Previous Interest Rate Swaps") with notional amounts of $50.0 million to establish fixed interest rates on a portion of the then outstanding borrowings under our Revolver through December 2010. During the first quarter of 2009, we discontinued hedge accounting for all of the Previous Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Previous Interest Rate Swaps have been recognized in the derivative line item on our Consolidated Statement of Income.

In September 2009, we paid off all amounts outstanding under the Revolver and, as a result, we reclassified the net hedging losses of $2.4 million remaining in accumulated other comprehensive income ("AOCI") related to the Interest Rate Swaps from AOCI to interest expense.

As there are currently no amounts outstanding under the Revolver, we entered into an offsetting fixed-to-floating interest rate swap in December 2009 that effectively unwinds the Previous Interest Rate Swaps. With respect to this fixed-to-floating interest rate swap, we pay a variable rate equivalent to the three-month LIBOR and the counterparties will pay a fixed rate of 0.53% until December 2010.

In December 2009, we entered into a new interest rate swap agreement ("New Interest Rate Swap") to establish variable rates on a portion of the outstanding obligation under the 10.375% Senior Unsecured Notes ("Senior Notes"). The notional amount of the New Interest Rate Swap is $100 million, or approximately one-third of the face amount outstanding under the Senior Notes. We will pay a variable rate equivalent to the three-month London Interbank Offered Rate ("LIBOR") plus a margin of 8.175%, and the counterparties will pay a fixed rate of 10.375%. The term of the New Interest Rate Swap extends through June 2013.

PVR Interest Rate Swaps

PVR has entered into interest rate swaps (the "PVR Interest Rate Swaps") to establish fixed rates on a portion of the outstanding borrowings under the PVR Revolver. Until March 2010, the notional amounts of the Interest Rate Swaps total $310.0 million, or approximately 50% of PVR's total long-term debt outstanding as of December 31, 2009, with PVR paying a weighted average fixed rate of 3.54% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From March 2010 to December 2011, the notional amounts of the Interest Rate Swaps total $250.0 million with PVR paying a weighted average fixed rate of 3.37% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. From December 2011 to December 2012, the notional amounts of the Interest Rate Swaps total $100.0 million, with PVR paying a weighted average fixed rate of 2.09% on the notional amount, and the counterparties paying a variable rate equal to the three-month LIBOR. The PVR Interest Rate Swaps extend one year past the maturity of the current PVR Revolver. The PVR Interest Rate Swaps have been entered into with seven financial institution counterparties, with no counterparty having more than 24% of the open positions.

During the first quarter of 2009, PVR discontinued hedge accounting for all of the PVR Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the PVR Interest Rate Swaps have been recognized in the derivatives line item on our Consolidated Statements of Income. At December 31, 2009, a $1.4 million loss remained in AOCI related to the PVR Interest Rate Swaps. The $1.4 million loss will be recognized in interest expense as the PVR Interest Rate Swaps settle.

PVR reported a (i) net derivative liability of $9.7 million at December 31, 2009 and (ii) loss in AOCI of $1.4 million at December 31, 2009 related to the PVR Interest Rate Swaps. In connection with periodic settlements, we recognized $3.4 million of net hedging losses in interest expense in the year ended December 31, 2009. Based upon future interest rate curves at December 31, 2009, we expect to realize

8. Derivative Financial Instruments – (continued)

$7.7 million of hedging losses within the next 12 months. The amounts that we ultimately realize will vary due to changes in the fair value of open derivative agreements prior to settlement.

Financial Statement Impact of Derivatives

The following table summarizes the effects of our consolidated derivative activities, as well as the location of the gains and losses, on our Consolidated Statements of Income for the periods presented (in thousands):

	Location of gain (loss) on derivatives recognized in income	Year Ended December 31, 2009	2008
Derivatives not designated as hedging instruments:			
Interest rate contracts(1)	Interest expense	(7,220)	(2,721)
Interest rate contracts	Derivatives	(5,956)	(8,635)
Commodity contracts(2)	Natural gas midstream revenues	—	(8,219)
Commodity contracts(2)	Cost of midstream gas purchased	—	2,739
Commodity contracts	Derivatives	17,810	55,217
Total increase in net income resulting from derivatives		$ 4,634	$ 38,381
Realized and unrealized derivative impact:			
Cash received (paid) for commodity and interest rate settlements	Derivatives	$ 61,147	$(46,086)
Cash paid for interest rate contract settlements	Interest expense	(808)	(1,518)
Unrealized derivative gain (loss)(3)		(55,705)	85,985
Total increase (decrease) in net income resulting from derivatives		$ 4,634	$ 38,381

(1) This represents Interest Rate Swap amounts reclassified out of AOCI and into earnings. During 2008 and 2009 PVR discontinued hedge accounting for various Interest Rate Swaps at different times. By the first quarter of 2009 PVR discontinued hedge accounting for the remaining Interest Rate Swaps. PVA discontinued hedge accounting for Interest Rate Swaps in first quarter 2009. During 2009 and 2008 PVA reclassified $3.8 million and $1.0 million for remaining AOCI and actual hedge settlements that were reclassified into earnings in the same period or periods relating to PVA Interest Rate Swaps not designated for hedge accounting. During 2009 and 2008 PVR reclassified $3.4 million and $1.7 million for remaining AOCI and actual hedge settlements that were reclassified into earnings in the same period or periods relating to PVR Interest Rate Swaps not designated for hedge accounting.

(2) This represents commodity derivative amounts reclassified out of AOCI and into earnings. Subsequent to the discontinuation of hedge accounting for commodity derivatives in 2006, amounts remaining in AOCI have been reclassified into earnings in the same period or periods during which the original hedge forecasted transaction affects earnings. No losses remain in AOCI related to commodity derivatives for which we discontinued hedge accounting in 2006.

(3) Represents unrealized gains (losses) in the natural gas midstream, cost of midstream gas purchased, interest expense and derivatives caption in our consolidated statements of income.

(in thousands, except per share amounts)

8. Derivative Financial Instruments – (continued)

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments on our Consolidated Balance Sheets for the periods presented:

		Fair Values as of December 31,			
		2009		2008	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives de-designated as hedging instruments:					
Interest rate contracts	Derivative liabilities – current	$ —	$ —	$ —	$ 3,177
Interest rate contracts	Derivative liabilities – noncurrent	—	—	—	3,648
Total derivatives de-designated as hedging instruments		—	—	—	6,825
Derivatives not designated as hedging instruments:					
Interest rate contracts	Derivative assets/liabilities – current	1,463	10,123	—	4,663
Interest rate contracts	Derivative assets/liabilities – noncurrent	1,266	5,575	—	5,073
Commodity contracts	Derivative assets/liabilities – current	16,109	6,024	67,569	7,694
Commodity contracts	Derivative assets/liabilities – noncurrent	2,364	1,170	4,070	—
Total derivatives not designated as hedging instruments		21,202	22,892	71,639	17,430
Total fair value of derivative instruments		$21,202	$22,892	$71,639	$24,255

See Note 4 for a description of how the above financial instruments are valued.

The effects of derivative gains (losses), cash settlements of our oil and gas commodity derivatives, cash settlements of PVR's natural gas midstream commodity derivatives, and cash settlements of the PVR Interest Rate Swaps are reported as adjustments to reconcile net income to net cash provided by operating activities on our Consolidated Statements of Cash Flows. These items are recorded in the "Total derivative losses (gains)" and "Cash settlements of derivatives" line on the Consolidated Statements of Cash Flows.

As of December 31, 2009, neither PVR nor we actively traded derivative instruments. In addition, as of December 31, 2009, neither PVR nor we owned derivative instruments containing credit risk contingencies.

9. Property and Equipment, net

The following table summarizes our property and equipment:

	As of December 31,	
	2009	2008
Oil and gas properties:		
Proved	$1,887,073	$1,951,325
Unproved	73,067	155,803
Total oil and gas properties	1,960,140	2,107,128
Other property and equipment:		
Coal properties	478,803	476,787
Midstream property and equipment	491,199	426,064
Land	20,743	20,985
Timber	87,869	87,869
Other property and equipment	68,359	64,766
Total property and equipment	3,107,113	3,183,599
Accumulated depreciation, depletion and amortization	(754,755)	(671,422)
	$2,352,358	$2,512,177

(in thousands, except per share amounts)

9. Property and Equipment, net – (continued)

The following table describes the changes in capitalized exploratory drilling costs that are pending the determination of proved reserves:

	2009		2008		2007	
	Number of Wells	Cost	Number of Wells	Cost	Number of Wells	Cost
Balance at beginning of year	1	$ 2,482	4	$ 4,336	1	$ 1,119
Additions pending determination of proved reserves	—	—	1	2,482	4	4,336
Reclassification to wells, equipment and facilities based on the determination of proved reserves	(1)	(2,482)	—	—	(1)	(1,119)
Charged to exploration expense	—	—	(4)	(4,336)	—	—
Balance at end of year	—	$ —	1	$ 2,482	4	$ 4,336

We had no capitalized exploratory drilling costs that had been under evaluation for a period greater than one year as of December 31, 2009, 2008 and 2007.

10. Equity Investments

The following table summarizes the activity associated with PVR's equity investments:

	Year Ended December 31,		
	2009	2008	2007
Balance at beginning of year	$78,443	$25,640	$25,355
Equity earnings	9,397	5,919	2,802
Amortization(1)	(2,125)	(1,743)	(1,017)
Investments(2)	6,622	52,577	—
Distributions	(4,736)	(3,950)	(1,500)
Balance at end of year	$87,601	$78,443	$25,640

(1) Reflects the amortization of intangible assets related to contracts and customer relationships acquired representing the excess of our investment over the underlying equity in the net assets.

(2) Primarily reflects the acquisition of PVR's 25% member interest in Thunder Creek during 2008 and PVR's 50% joint venture investment in Crosspoint Pipeline during 2009.

11. Intangible Assets and Goodwill

The following table summarizes PVR's net intangible assets:

	As of December 31,	
	2009	2008
Contracts and customer relationships	$104,700	$106,900
Rights-of-way	4,552	4,552
Total intangible assets	109,252	111,452
Accumulated amortization	(25,511)	(18,780)
	$ 83,741	$ 92,672

(in thousands, except per share amounts)

11. Intangible Assets and Goodwill – (continued)

The contracts and customer relationships and rights-of-way were primarily acquired by PVR in the Lone Star acquisition (see Note 5). PVR also has contract and customer relationship intangible assets included within its equity investments (see Note 10). Contracts and customer relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, up to 20 years. Total intangible amortization expense for the years ended December 31, 2009, 2007 and 2006 was approximately $7.4 million, $5.5 million and $4.1 million, respectively.

The following table sets forth our estimated aggregate amortization expense for the next five years and thereafter:

Year	Amortization Expense
2010	$ 6,791
2011	6,285
2012	5,718
2013	5,499
2014	5,346
Thereafter	54,102
Total	$83,741

PVR's annual impairment testing of goodwill resulted in an impairment to goodwill of approximately $31.8 million in the fourth quarter of 2008. The impairment charge, which was triggered by declines in oil and gas spot and futures prices and a decline in PVR's market capitalization during the fourth quarter of 2008, reduced to zero all goodwill recorded in conjunction with acquisitions made by the PVR natural gas midstream segment in 2008 and prior years. As of December 31, 2009 and 2008, we had no goodwill recorded.

In determining the fair value of the PVR natural gas midstream segment (reporting unit) in 2008, we used an income approach. Under the income approach, the fair value of the reporting unit was estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, appropriate discount rates and a market-derived earnings multiple terminal value (the value of the reporting unit at the end of the estimation period).

Key assumptions used in the discounted cash flows model described above include estimates of future commodity prices based on the December 31, 2008 commodity price strips and estimates of operating, administrative and capital costs. We discounted the resulting future cash flows using a PVR peer company based weighted average cost of capital of 12%.

This loss was recorded in the impairment line on our Consolidated Statements of Income. The goodwill impairment loss reflects the negative impact of certain factors which resulted in a reduction in the anticipated cash flows used to estimate fair value. The business and marketplace environments in which PVR currently operates differs from the historical environments that drove the factors used to value and record the acquisition of these business units.

(in thousands, except per share amounts)

12. Debt

The following table summarizes our long-term debt:

	As of December 31,	
	2009	2008
Short-term borrowings[1]	$ —	$ 7,542
Revolving credit facility	—	332,000
Senior notes, net of discount	291,749	—
Convertible notes, net of discount	206,678	199,896
PVR revolving credit facility	620,100	568,100
Total debt	1,118,527	1,107,538
Less: Short-term borrowings	—	(7,542)
	$1,118,527	$1,099,996

(1) The short-term borrowings reflect a book overdraft for 2008.

Revolving Credit Facility

In November 2009, we entered into the Revolver and simultaneously terminated our previous credit agreement. The Revolver provides for a $300 million revolving credit facility and matures in November 2012. We have the option to increase the commitments under the Revolver by up to an additional $225 million upon the receipt of commitments from one or more lenders. The Revolver is governed by a borrowing base calculation and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The initial borrowing base was $420 million and was reduced to $380 million in connection with the sale of our Gulf Coast properties as discussed previously. The borrowing base is redetermined semi-annually. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions and includes a $20 million sublimit for the issuance of letters of credit.

The Revolver's financial covenants include a minimum current ratio, as defined in the credit agreement, and our total debt to EBITDAX, a non-GAAP measure, must not exceed a specified ratio. The Revolver contains various other covenants that limit our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2009, we were in compliance with all of our covenants under the Revolver.

Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from LIBOR, as adjusted for statutory reserve requirements for Eurocurrency liabilities (the "Adjusted LIBOR"), plus an applicable margin ranging from 2.000% to 3.000% or (ii) the greater of (a) the prime rate, (b) federal funds effective rate plus 0.5% and (c) the one-month Adjusted LIBOR plus 1.0%, in each case, plus an applicable margin (ranging from 1.000% to 2.000%). In each case, the applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. During 2009, we incurred commitment fees of $0.4 million on the unused portion of the Revolver and that of the credit facility under the previous credit agreement.

The Revolver is guaranteed by Penn Virginia and all of our material oil and gas subsidiaries. The obligations under the Revolver are secured by a first priority lien on a portion of our proved oil and gas reserves and a pledge of the equity interests in the guarantor subsidiaries.

As of December 31, 2009, there were no amounts outstanding under the Revolver and we had remaining borrowing capacity of up to $299.3 million, net of outstanding letters of credit of $0.7 million.

(in thousands, except per share amounts)

12. Debt – (continued)

Senior Notes

In June 2009, we issued and sold $300 million of Senior Notes which mature in June 2016. The Senior Notes were sold at 97% of par, equating to an effective yield to maturity of approximately 11%. The net proceeds from the sale of the Senior Notes of $281.6 million were used to repay borrowings under the revolving credit facility associated with the previous credit agreement. The Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by our subsidiaries that guarantee our indebtedness under the Revolver.

Convertible Notes

In December 2007, we issued 4.50% Convertible Notes ("Convertible Notes") with interest payable semiannually in arrears on May 15 and November 15 of each year. The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment, and, if not converted or repurchased earlier, will mature in November 2012.

The Convertible Notes are represented by a liability component which is reflected herein as long-term debt, net of discount and an equity component which is included in additional paid-in capital in shareholders' equity representing the convertible feature. The following table summarizes the carrying amount of these components for the periods presented:

	As of December 31,	
	2009	2008
Principal	$230,000	$230,000
Unamortized discount	(23,322)	(30,104)
Net carrying amount of liability component	$206,678	$199,896
Carrying amount of equity component	$ 36,850	$ 36,850

The unamortized discount will be amortized through the end of 2012. The effective interest rate on the liability component of the Convertible Notes for the years ended December 31, 2009 and 2008 was 8.5%. During both 2009 and 2008, we recognized $10.4 million of interest expense related to the contractual coupon rate on the Convertible Notes and $6.8 million of interest expense related to the amortization of the discount.

The Convertible Notes are unsecured senior subordinated obligations, ranking junior in right of payment to any of our senior indebtedness and to any of our secured indebtedness to the extent of the value of the assets securing such indebtedness and equal in right of payment to any of our future unsecured senior subordinated indebtedness. The Convertible Notes will rank senior in right of payment to any of our future junior subordinated indebtedness and will structurally rank junior to all existing and future indebtedness of our guarantor subsidiaries.

In connection with the sale of the Convertible Notes, we entered into convertible note hedge transactions ("Note Hedges") with respect to shares of our common stock with affiliates of certain of the underwriters of the Convertible Notes (collectively, the "Option Counterparties"). The Note Hedges cover, subject to anti-dilution adjustments, the net shares of our common stock that would be deliverable to converting noteholders in the event of a conversion of the Convertible Notes.

12. Debt – (continued)

We also entered into separate warrant transactions, ("Warrants"), whereby we sold to the Option Counterparties warrants to acquire, subject to anti-dilution adjustments, approximately 3,982,680 shares of our common stock at an exercise price of $74.25 per share. Upon exercise of the Warrants, we will deliver shares of our common stock equal to the difference between the then market price and the strike price of the Warrants.

If the market value per share of our common stock at the time of conversion of the Convertible Notes is above the strike price of the Note Hedges, the Note Hedges entitle us to receive from the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount) based on the excess of the then current market price of our common stock over the strike price of the Note Hedges. Additionally, if the market price of our common stock at the time of exercise of the Warrants exceeds the strike price of the Warrants, we will owe the Option Counterparties net shares of our common stock (and cash for any fractional share cash amount), not offset by the Note Hedges, in an amount based on the excess of the then current market price of our common stock over the strike price of the Warrants.

On October 3, 2008, one of the Option Counterparties, Lehman Brothers OTC Derivatives Inc. ("Lehman OTC") joined other Lehman Brothers entities and filed for bankruptcy protection. We had purchased 22.5% of the Note Hedges from Lehman OTC ("Lehman Note Hedges") for approximately $8.3 million, and we had sold 22.5% of the Warrants to Lehman OTC for approximately $4.1 million. If the Lehman Note Hedges are rejected or terminated in connection with the Lehman OTC bankruptcy, we would have a claim against Lehman OTC and possibly Lehman Brothers Inc., as guarantor, for the damages and/or close-out values resulting from any such rejection or termination. While we intend to pursue any claim for damages and/or close-out values resulting from the rejection or termination of the Lehman Note Hedges, at this point in the Lehman bankruptcy cases it is not possible to determine with accuracy the ultimate recovery, if any, that we may realize on potential claims against Lehman OTC or its affiliated guarantor resulting from any rejection or termination of the Lehman Note Hedges. We also do not know whether Lehman OTC will assume or reject the Lehman Note Hedges, and therefore cannot predict whether Lehman OTC intends to perform its obligations under the Lehman Note Hedges. If Lehman OTC does not perform such obligations and the price of our common stock exceeds the $57.75 conversion price (as adjusted) of the Convertible Notes, our existing shareholders would experience dilution at the time or times the Convertible Notes are converted. The extent of any such dilution would depend, among other things, on the then prevailing market price of our common stock and the number of shares of common stock then outstanding, but we believe the impact will not be material and will not affect our income statement presentation. We are not otherwise exposed to counterparty risk related to the bankruptcies of Lehman Brothers Inc. or its affiliates and do not believe that the Lehman bankruptcies will have a material adverse effect on our financial condition or results of operations.

PVR Revolving Credit Facility

As of December 31, 2009, the long-term debt of PVR was solely attributable to the PVR Revolver. In March 2009, PVR increased the size of the PVR Revolver from $700 million to $800 million. The PVR Revolver is secured with substantially all of PVR's assets. As of December 31, 2009, PVR had remaining borrowing capacity of $178.3 million on the PVR Revolver, net of outstanding indebtedness of $620.1 million and letters of credit of $1.6 million. The PVR Revolver matures in December 2011 and is available to PVR for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10.0 million sublimit for the issuance of letters of credit. Interest is payable at a base rate plus an applicable margin of up to 1.25% if PVR selects the base rate borrowing option or at a rate derived from LIBOR plus an applicable margin ranging from 1.75% to 2.75% if PVR selects the LIBOR-based borrowing option. At December 31, 2009, the base rate applicable margin was 0.75% and the LIBOR-based rate applicable margin was 2.25%. During 2009, PVR incurred commitment fees of $0.5 million on the unused portion of the PVR Revolver. The weighted average interest rate on indebtedness outstanding under the PVR Revolver during 2009 was approximately 2.7%. Debt outstanding under the PVR Revolver is non-recourse to us and PVG.

(in thousands, except per share amounts)

12. Debt – (continued)

The financial covenants under the PVR Revolver require PVR not to exceed specified ratios. The PVR Revolver prohibits PVR from making distributions to its partners if any potential default, or event of default, as defined in the PVR Revolver, occurs or would result from the distributions. In addition, the PVR Revolver contains various covenants that limits PVR's ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of its business, or enter into a merger or sale of our assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2009, PVR was in compliance with all of its covenants under the PVR Revolver.

Debt Maturities

The following table sets forth the aggregate maturities of the principal amounts of our and PVR's long-term debt for the next five years and thereafter:

Year	Aggregate Maturities of Principal Amounts
2010	$ —
2011	620,100
2012	206,678
2013	—
2014	—
Thereafter	291,749
Total	$1,118,527

13. Income Taxes

Due to the geographical scope of our operations, we are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

No liability for unrecognized tax benefits remained at December 31, 2009. The liability for unrecognized tax benefits at December 31, 2008 included $3.3 million of tax positions which changed the effective tax rate in 2009, when settled. For the years ended December 31, 2009, 2008 and 2007, we recognized $0.1 million, $0.5 million and $0.7 million in interest and penalties. We had accrued interest and penalties of $1.8 million as of December 31, 2008. Tax years from 2006 forward remain open for examination by the Internal Revenue Service. Tax years from 2005 forward remain open for state jurisdictions.

(in thousands, except per share amounts)

13. Income Taxes – (continued)

A reconciliation of our unrecognized tax benefits for the periods presented is as follows

	Year Ended December 31,		
	2009	2008	2007
Balance at beginning of year	$ 4,600	$ 9,852	$ 8,737
Additions as a result of tax positions taken in the current year	78	220	1,659
Additions as a result of tax positions taken in prior years	100	461	—
Settlements	(4,778)	(5,933)	(544)
Balance at end of year	—	4,600	9,852
Less: current portion	—	(1,800)	(1,466)
Long-term portion	$ —	$ 2,800	$ 8,386

In the years ended December 31, 2009, 2008 and 2007, we paid $2.5 million, $2.2 million and $0.4 million, respectively, in cash to settle uncertain tax positions. In the same years, we recognized $2.1 million, $3.7 million and $0.1 million in tax and interest benefits related to waived taxes, penalties and interest in connection with settlement.

The following table summarizes our provision for income taxes from continuing operations for the periods presented:

	Year Ended December 31,		
	2009	2008	2007
Current income taxes (benefit)			
Federal	$ 6,572	$13,838	$ 6,212
State	1,398	(469)	949
Total current	7,970	13,369	7,161
Deferred income taxes (benefit)			
Federal	(68,488)	48,617	19,646
State	(14,734)	9,934	3,525
Total deferred	(83,222)	58,551	23,171
	$(75,252)	$71,920	$30,332

The following table reconciles the difference between the taxes computed by applying the statutory tax rate to income from operations before income taxes and our reported income tax expense for the periods presented:

	Year Ended December 31,					
	2009		2008		2007	
Computed at federal statutory rate	$(66,463)	(35.0)%	$67,606	35.0%	$28,290	35.0%
State income taxes, net of federal income tax benefit	(7,036)	(3.7)%	7,284	3.8%	3,257	4.0%
Other, net	(1,753)	(0.9)%	(2,970)	(1.5)%	(1,215)	(1.5)%
	$(75,252)	(39.6)%	$71,920	37.3%	$30,332	37.5%

(in thousands, except per share amounts)

13. Income Taxes – (continued)

The following table summarizes the principal components of our net deferred income tax liability for the periods presented:

	As of December 31,	
	2009	2008
Deferred tax liabilities:		
Property and equipment	$347,627	$392,037
Fair value of derivative instruments	—	6,919
Convertible notes	9,027	12,248
Other	11,683	—
Total deferred tax liabilities	368,337	411,204
Deferred tax assets:		
Fair value of derivative instruments	9,194	—
Deferred income – coal properties	9,069	9,732
Pension and postretirement benefits	4,096	4,279
Stock-based compensation	5,349	4,699
Net operating loss carryforwards	1,806	—
Other	12,768	2,971
	42,282	21,681
Less: Valuation allowance	(885)	—
Total deferred tax assets	41,397	21,681
Net deferred tax liability	$326,940	$389,523

In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible. Among other items, we consider the scheduled reversal of deferred tax liabilities, projected future taxable income and available tax planning strategies. As of December 31, 2009, a valuation allowance of $0.9 million had been recorded for deferred tax assets that were not more likely than not to be realized. As of December 31, 2008, no valuation allowance had been recorded because we estimated that it was more likely than not that all of our deferred tax assets would be realized. The net operating losses, if unused, will expire in the years 2024 to 2029.

14. Asset Retirement Obligations

The following table reconciles our AROs for the periods presented, which are included in other liabilities on our Consolidated Balance Sheets:

	Year Ended December 31,	
	2009	2008
Balance at beginning of year	$8,589	$7,873
Liabilities incurred	411	487
Revision of estimates	—	(505)
Liabilities settled	(142)	9
Transfers[1]	(500)	—
Accretion expense	491	725
Balance at end of year	$8,849	$8,589

(1) An ARO was transferred to Liabilities held for sale in connection with the sale of our Gulf Coast properties (see Note 5).

(in thousands, except per share amounts)

15. Commitments and Contingencies

Penn Virginia Corporation Commitments

The following table sets forth our significant commitments, by category, for the next five years and thereafter. A discussion of these items follows:

	Penn Virginia Corporation		
Year	Minimum Rental Commitments	Drilling Commitments	Firm Transportation Commitments
2010	$ 4,209	$19,883	$ 3,746
2011	2,662	8,458	3,746
2012	1,516	—	3,510
2013	1,449	—	2,779
2014	1,458	—	2,689
Thereafter	5,119	—	15,001
Total	$16,413	$28,341	$31,471

Rental Commitments

Operating lease rental expense in the years ended December 31, 2009, 2008 and 2007 was $18.0 million, $18.5 million and $13.4 million.

Our rental commitments primarily relate to equipment and building leases.

Drilling Commitments

We have agreements to purchase oil and gas well drilling services from third parties with terms that range up to three years. The agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their original terms. The amount of penalty is based on the number of days remaining in the contractual term and declines as time passes. As of December 31, 2009, the penalty amount would have been $38.3 million if we had terminated our agreements on that date. Our management intends to utilize drilling services under these agreements for the full terms and has no plans to terminate the agreements early.

Oil and Gas Segment Firm Transportation Commitments

We have entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system with terms that ranged from one to 10 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

(in thousands, except per share amounts)

15. Commitments and Contingencies – (continued)

PVR Commitments

The following table sets forth PVR's significant commitments, by category, for the next five years and thereafter. A discussion of these items follows:

	PVR	
Year	Minimum Rental Commitments	Firm Transportation Commitments
2010	$ 4,243	$13,103
2011	3,413	5,694
2012	3,017	4,508
2013	2,971	4,033
2014	2,893	3,321
Thereafter	7,943	1,661
Total	$24,480	$32,320

Rental Commitments

Operating lease rental expense in the years ended December 31, 2009, 2008 and 2007 was $7.5 million, $4.5 million and $2.6 million.

PVR rental commitments primarily relate to equipment and building leases and leases of coal reserve-based properties which PVR subleases, or intends to sublease, to third parties. The obligation with respect to leased properties which PVR subleases expires when the property has been mined to exhaustion or the lease has been canceled. The timing of mining by third party operators is difficult to estimate due to numerous factors. PVR believes that its future rental commitments with regard to this subleased property cannot be estimated with certainty.

PVR Natural Gas Midstream Segment Firm Transportation Commitments

As of December 31, 2009, PVR had contracts for firm transportation capacity rights for specified volumes per day on a pipeline system with terms that ranged from one to seven years. The contracts require PVR to pay transportation demand charges regardless of the amount of pipeline capacity PVR uses. PVR may sell excess capacity to third parties at its discretion.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position or results of operations.

Environmental Compliance

Extensive federal, state and local laws govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration or production activities in

(in thousands, except per share amounts)

15. Commitments and Contingencies – (continued)

sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

PVR's operations and those of its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The terms of PVR's coal property leases impose liability on the relevant lessees for all environmental and reclamation liabilities arising under those laws and regulations. The lessees are bonded and have indemnified PVR against any and all future environmental liabilities. PVR regularly visits its coal properties to monitor lessee compliance with environmental laws and regulations and to review mining activities. PVR's management believes that its operations and those of its lessees comply with existing laws and regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2009 and 2008, PVR's environmental liabilities were $1.0 million and $1.2 million, which represents PVR's best estimate of the liabilities as of those dates related to its coal and natural resource management and natural gas midstream businesses. PVR has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when a reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

Mine Health and Safety Laws

There are numerous mine health and safety laws and regulations applicable to the coal mining industry. However, since PVR does not operate any mines and does not employ any coal miners, PVR is not subject to such laws and regulations. Accordingly, we have not accrued any related liabilities.

16. Additional Balance Sheet Detail

The following tables summarize components of selected balance sheet accounts:

	As of December 31,	
	2009	2008
Accounts payable and accrued liabilities:		
Deferred income	$ 5,234	$ 6,211
Drilling costs	11,203	54,477
Royalties	6,717	9,495
Production and franchise taxes	11,189	12,062
Compensation	11,582	11,011
Interest	3,759	3,049
Liabilities held for sale	500	—
Deposit received on properties to be sold	2,280	—
Other	5,754	4,333
Total accrued liabilities	58,218	100,638
Accounts payable	79,170	106,264
	$137,388	$206,902

(in thousands, except per share amounts)

16. Additional Balance Sheet Detail – (continued)

	As of December 31, 2009	2008
Other liabilities:		
Deferred income – PVR Coal	$18,371	$20,260
Asset retirement obligations	8,849	8,589
Pension	1,762	1,891
Postretirement health care	3,452	3,478
Environmental obligations	861	974
Unrecognized tax benefits	—	2,800
Deferred compensation	9,741	7,435
Other	427	460
	$43,463	$45,887

17. Shareholders Equity'

In September 2009, we sold 10 million units of PVG owned by us for proceeds of $118.1 million, net of offering costs resulting in a reduction of our limited partner interest in PVG from 77.0% to 51.4%. The transaction resulted in a $67.7 million increase in noncontrolling interests and a $50.4 million increase to additional paid-in capital less $17.7 million for deferred income tax effects.

In May 2009, we issued 3,500,000 shares of our common stock in a registered public offering that provided $64.8 million of net proceeds. The net proceeds were used in addition to the Senior Notes to repay our borrowings under our previous revolving credit facility.

In December 2007, we completed the sale of 3,450,000 shares of our common stock in a registered public offering. The net proceeds of the sale were $135.4 million and were used to repay a portion of the outstanding borrowings under our previous revolving credit facility and for general corporate purposes.

Comprehensive income represents changes in shareholders' equity during the reporting period, including net income (loss) and charges directly to shareholders' equity which are excluded from net income. The following table sets forth the components of comprehensive income for the periods presented:

	Cash Flow Hedges	Other	Total
Year ended December 31, 2009:			
Hedging unrealized losses, net of tax of ($62)	$ 115	$ —	$ 115
Hedging reclassification adjustment, net of tax of $1,986	3,689	—	3,689
Other, net of tax of $75	—	140	140
Other comprehensive income	$ 3,804	$140	$ 3,944
Year ended December 31, 2008:			
Hedging unrealized losses, net of tax of ($2,352)	$(4,368)	$ —	$(4,368)
Hedging reclassification adjustment, net of tax of $2,871	5,332	—	5,332
Other, net of tax of $186	—	346	346
Other comprehensive income	$ 964	$346	$ 1,310
Year ended December 31, 2007:			
Hedging unrealized losses, net of tax of ($1,432)	$(2,659)	$ —	$(2,659)
Hedging reclassification adjustment, net of tax of $1,499	2,691	—	2,691
Other, net of tax of ($8)	—	(14)	(14)
Other comprehensive income	$ 32	$(14)	$ 18

(in thousands, except per share amounts)

18. Share-Based Compensation

Stock Compensation Plans

We have several stock compensation plans (collectively, the "Stock Compensation Plans") that allow incentive and nonqualified stock options and restricted stock to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. At December 31, 2009, there were approximately 1,615,410 and 376,595 shares available for issuance to employees and directors pursuant to the Stock Compensation Plans, respectively. For the years ended December 31, 2009, 2008 and 2007, we recognized \$9.1 million, \$5.9 million and \$4.1 million of compensation expense related to the Stock Compensation Plans, which is reflected in the general and administrative expense line of the Consolidated Statements of Income. The total income tax benefit recognized in the Consolidated Statements of Income for the Stock Compensation Plans was \$3.5 million, \$2.3 million and \$1.6 million for the years ended December 31, 2009, 2008 and 2007.

Stock Options. The exercise price of all options granted under the Stock Compensation Plans is equal to the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors (the "Committee"). Generally, options vest ratably over a three-year period, with one-third vesting in each year. In addition, all options will vest upon a change of control of us, as defined by the Stock Compensation Plans. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be automatically forfeited, (ii) by reason of death, disability or retirement (age 62 and providing ten consecutive years of service) the grantee's options will automatically vest and (iii) for any other reason, the grantee's unvested options will be automatically forfeited. In the case of directors, if a grantee's membership on our board of directors terminates for any reason, the grantee's unvested options will be automatically forfeited. We have a policy of issuing new shares to satisfy share option exercises.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	2009	2008	2007
Expected volatility	51.7% to 64.9%	38.5% to 56.1%	30.0% to 38.5%
Dividend yield	1.25% to 1.49%	0.37% to 0.67%	0.51% to 0.63%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	1.23% to 1.84%	1.86% to 2.87%	3.86% to 4.72%

(in thousands, except per share amounts)

18. Share-Based Compensation – (continued)

The following table summarizes activity for our most recent fiscal year with respect to common stock options awarded:

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	1,377,215	$33.38		
Granted	1,162,472	15.10		
Exercised	—	—		
Forfeited	(262,770)	26.30		
Outstanding at end of year	2,276,917	$24.86	7.7	$7,912
Exercisable at end of year	1,102,673	$27.48	6.6	$2,916

The weighted-average grant-date fair value of options granted during the years ended December 31, 2009, 2008 and 2007 was $5.60, $13.20 and $9.83 per option. The total intrinsic value of options exercised during the years ended December 31, 2008 and 2007 was $13.1 million and $10.0 million. There were no options exercised during 2009.

As of December 31, 2009, we had $6.5 million of total unrecognized compensation cost related to nonvested stock options. We expect that cost to be recognized over a weighted-average period of 0.9 years. The total grant-date fair value of stock options that vested in 2009, 2008 and 2007 was $5.7 million, $2.7 million and $1.8 million.

Restricted Stock. Restricted stock vests upon terms established by the Committee and as specified in the award agreement. In addition, all restricted stock will vest upon a change of control of us. If a grantee's employment terminates for any reason other than death or disability, the grantee's restricted stock will be automatically forfeited unless otherwise determined by the Committee and specified in the award agreement. If a grantee's employment terminates by reason of death or disability, or if a grantee becomes retirement eligible (age 62 and providing 10 consecutive years of service), the grantee's restricted stock will automatically vest. Except as specified by the Committee, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock vests over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

The following table summarizes the status of our nonvested restricted stock as of December 31, 2009 and changes during the year then ended:

	Nonvested Restricted Stock	Weighted-Average Grant Date Fair Value
Balance at beginning of year	54,400	$ 40.06
Vested	(33,740)	(39.60)
Balance at end of year	20,660	$ 40.82

At December 31, 2009, we had $0.4 million of total unrecognized compensation cost related to nonvested restricted stock. We expect that cost to be recognized over a weighted-average period of 0.6 years. The total grant-date fair value of restricted stock that vested in the years ended December 31, 2009, 2008 and 2007 was $1.3 million, $1.0 million and $0.6 million.

(in thousands, except per share amounts)

18. Share-Based Compensation – (continued)

Deferred Common Stock Units. A portion of the compensation paid to non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, which vests immediately upon issuance and is available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on account of shares of our common stock.

The following table summarizes activity for the most recent fiscal year with respect to deferred common stock units awarded:

	Deferred Common Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	66,077	$33.86
Granted	29,045	19.55
Converted	(11,936)	32.01
Balance at end of year	83,186	$29.13

The aggregate intrinsic value of deferred common stock units converted to shares of common stock in the year ended December 31, 2007 was $0.3 million.

We recorded a $2.4 million, $2.2 million and $1.6 million deferred compensation obligation in shareholders' equity at December 31, 2009, 2008 and 2007 and a corresponding amount for treasury stock.

Deferred Phantom Stock Units. A phantom unit entitles the grantee to receive a share of common stock upon the vesting of the phantom unit, or in the discretion of the Committee, the cash equivalent of the value of a share of common stock. The Committee determines the time period over which phantom units granted to employees and directors will vest. In addition, all phantom units will vest upon a change of control. If a director's membership on the board of directors terminates for any reason, or an employee's employment with us and our affiliates terminates for any reason other than retirement after reaching age 62 and completing 10 years of consecutive service, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Committee provides otherwise. Phantom units generally vest over a three-year period, with one-third vesting in each year. The Committee, in its discretion, may grant tandem dividend equivalent rights with respect to phantom units. A dividend equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash dividends made with respect to a share of common stock during the period such phantom unit is outstanding. Payments of dividend equivalent rights associated with shares of common stock that are expected to vest are recorded as dividends; however, payments associated with units that are not expected to vest are recorded as compensation expense.

The following table summarizes activity for the most recent fiscal year with respect to phantom stock units awarded:

	Deferred Phantom Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	—	$ —
Granted	111,755	15.42
Vested	(39,841)	(15.06)
Balance at end of year	71,914	$ 15.62

(in thousands, except per share amounts)

18. Share-Based Compensation – (continued)

PVG Long-Term Incentive Plan

PVG's general partner has adopted a long-term incentive plan. PVG's long-term incentive plan permits the grant of awards to employees and directors of PVG's general partner and employees of its affiliates who perform services for PVG. Awards under the PVG's long-term incentive plan can be in the form of PVG common units, restricted PVG units, PVG unit options, phantom PVG units and deferred PVG common units. The PVG long-term incentive plan is administered by the compensation and benefits committee of the board of directors of PVG's general partner (the "PVG Committee"). PVG reimburses its general partner for payments made pursuant to the PVG long-term incentive plan. PVG recognizes compensation cost based on the fair value of the awards over the vesting period.

PVG recognized compensation expense related to its long-term incentive plan of $0.4 million for each of the years ended December 31, 2009, 2008 and 2007 Compensation expense is recorded on the general and administrative expense line on the Consolidated Statements of Income.

Deferred PVG Common Units. A portion of the compensation to the non-employee directors of PVG's general partner is paid in deferred PVG common units. Each deferred PVG common unit represents one PVG common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of PVG's general partner. The fair value of the deferred PVG common units is calculated based on the grant date unit price.

The following table summarizes activity for the most recent fiscal year with respect to deferred PVG common units awarded:

	Deferred PVG Common Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	32,128	$23.40
Granted and vested	32,172	13.28
Balance at end of year	64,300	$18.34

PVR Long-Term Incentive Plan

PVR's general partner has adopted a long-term incentive plan. PVR's long-term incentive plan permits the grant of awards to employees and directors of PVR's general partner and employees of its affiliates who perform services for PVR. In January 2009, PVR's general partner increased the number of common units permitted to be granted under the long-term incentive plan to 3,000,000 PVR common units. Awards under the PVR long-term incentive plan can be in the form of PVR common units, restricted PVR units, PVR unit options, phantom PVR units and deferred PVR common units. The PVR long-term incentive plan is administered by the compensation and benefits committee of the board of directors of PVR's general partner (the "PVR Committee"). PVR reimburses its general partner for payments made pursuant to the PVR long-term incentive plan. PVR recognizes compensation cost based on the fair value of the awards over the vesting period.

PVR recognized a total of $4.8 million, $3.2 million and $2.4 million in the years ended December 31, 2009, 2008 and 2007 of compensation expense related to the granting of common units and deferred common units and the vesting of restricted units granted under the long-term incentive plan. Compensation expense is recorded on the general and administrative expense line on the Consolidated Statements of Income.

(in thousands, except per share amounts)

18. Share-Based Compensation – (continued)

PVR Common Units. PVR's common units, which are granted to non-employee directors, vest immediately upon issuance. PVR's general partner granted 1,871 common units at a weighted average grant-date fair value of $15.46 per unit to non-employee directors in 2009. PVR's general partner granted 1,525 common units at a weighted average grant date fair value of $20.27 per unit to non-employee directors in 2008. PVR's general partner granted 1,183 common units at a weighted average grant-date fair value of $27.09 per unit to non-employee directors in 2007. The fair value of the PVR common units is calculated based on grant-date unit price.

Deferred PVR Common Units. A portion of the compensation to the non-employee directors of PVR's general partner is paid in deferred PVR common units. Each deferred PVR common unit represents one PVR common unit, which vests immediately upon issuance and is available to the holder upon termination or retirement from the board of directors of PVR's general partner.

The following table summarizes the activity for the most recent fiscal year with respect to deferred PVR units awarded:

	Deferred PVR Common Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	63,569	$23.98
Granted and vested	35,819	15.62
Balance at end of year	99,388	$20.97

No deferred PVR common units converted to PVR common units in 2009. The fair value of the deferred PVR common units is calculated based on the grant date unit price.

Restricted PVR Units. Restricted PVR units vest upon terms established by the PVR Committee. In addition, all restricted PVR units will vest upon a change of control of PVR's general partner or us. If a grantee's employment with, or membership on the board of directors of, PVR's general partner terminates for any reason, the grantee's unvested restricted PVR units will be automatically forfeited unless, and to the extent that, the PVR Committee provides otherwise. Distributions payable with respect to restricted PVR units may, in the PVR Committee's discretion, be paid directly to the grantee or held by PVR's general partner and made subject to a risk of forfeiture during the applicable restriction period. Restricted PVR units generally vest over a three-year period, with one-third vesting in each year.

The following table summarizes the activity for the most recent fiscal year with respect to restricted PVR units awarded:

	Nonvested Restricted PVR Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	221,855	$26.93
Vested	(128,106)	27.19
Forfeited	(940)	26.36
Balance at end of year	92,809	$26.57

At December 31, 2009, PVR had $1.2 million of total unrecognized compensation cost related to nonvested restricted units. PVR expects to reimburse its general partner for that cost over a weighted-average period of 0.3 years. The total grant-date fair value of restricted units that vested in 2009, 2008 and 2007 was $3.5 million, $1.9 million and $1.2 million.

(in thousands, except per share amounts)

18. Share-Based Compensation – (continued)

PVR Phantom Units. A phantom PVR unit entitles the grantee to receive a common PVR unit upon the vesting of the phantom PVR unit, or in the discretion of the PVR Committee, the cash equivalent of the value of a common PVR unit. The PVR Committee determines the time period over which phantom units granted to employees and directors will vest. In addition, all phantom PVR units will vest upon a change of control of PVR's partner or us. If a director's membership on the board of directors of its general partner terminates for any reason, or an employee's employment with PVR's general partner and its affiliates terminates for any reason other than retirement after reaching age 62 and completing 10 years of consecutive service, the grantee's phantom PVR units will be automatically forfeited unless, and to the extent, the PVR Committee provides otherwise. Phantom PVR units generally vest over a three-year period, with one-third vesting in each year. The PVR Committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom PVR units. A distribution equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash distributions made with respect to a common PVR unit during the period such phantom PVR unit is outstanding. Payments of distribution equivalent rights associated with units that are expected to vest are recorded as capital distributions; however, payments associated with PVR units that are not expected to vest are recorded as compensation expense.

The following table summarizes the status of PVR phantom units as of December 31, 2009 and changes during the year then ended:

	Nonvested Phantom Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	—	$ —
Granted	354,792	11.59
Vested	(75,410)	11.59
Forfeited	(2,379)	11.59
Balance at end of year	277,003	$11.59

At December 31, 2009, PVR had $2.3 million of total unrecognized compensation cost related to nonvested phantom PVR units. The total grant-date fair value of phantom PVR units that vested on 2009 was $0.9 million.

19. Impairments

The following table summarizes impairment charges recorded during the periods presented:

	Year Ended December 31,		
	2009	2008	2007
Oil and gas properties(1)	$ 4,932	$19,963	$2,586
Assets held for sale(2)	97,400	—	—
Inventories	4,083	—	—
Goodwill(3)	—	31,801	—
Other	1,511	—	—
	$107,926	$51,764	$2,586

(1) Charges in 2009 relate to declines in spot and future oil and gas prices which reduced reserves on certain properties in the Mid-Continent region. Charges in 2008 relate to declines in spot and future oil and gas prices and declines in well performance which reduced reserves on certain properties in the

(in thousands, except per share amounts)

19. Impairments – (continued)

Mid-Continent and Appalachian regions. Charges in 2007 relate to changes in estimates of reserve bases of fields on certain properties in Oklahoma and Texas due to declines in well performance.

(2) Reflects an adjustment to fair value less costs to sell for oil and gas properties held for sale located in the Gulf Coast region (see Note 5).

(3) Reflects the negative impact of declines in oil and gas spot and futures prices and a decline in PVR's market capitalization which reduced to zero all goodwill recorded in conjunction with acquisitions made by the PVR natural gas midstream segment.

20. Restructuring Activities

In November 2009, we implemented an organization restructuring that will result in the transfer of certain corporate and oil and gas accounting and administrative functions from our Kingsport, Tennessee office location to our Houston, Texas and Radnor, Pennsylvania locations. In addition, the restructuring will result in the relocation of our eastern region oil and gas divisional office from Kingsport to a new office in Pittsburgh, Pennsylvania. Approximately 30 employees will be terminated in connection with the restructuring plans. We expect to incur approximately $1.2 million in special termination benefit costs which will be paid to eligible employees upon the completion of various transition activities. Accordingly, these costs will be charged to operations ratably over the transition period which is anticipated to be completed in March 2010. In addition, we anticipate incurring approximately $1.2 million in relocation costs as well as $1.5 million in other incremental costs associated with expanding our other office locations.

The following table summarizes the cumulative obligation recognized and the charges incurred as of and for the year ended December 31, 2009:

Balance at beginning of year	$ —
Termination benefits accrued	529
Cash payments	—
Balance at end of year	$529

21. Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31,		
	2009	2008	2007
Interest and accretion on borrowings and related fees	$65,203	$50,679	$42,624
Interest rate swaps	7,220	2,721	(737)
Other	(996)	(439)	488
Capitalized interest	(2,543)	(3,662)	(4,524)
	$68,884	$49,299	$37,851

22. Changes in Accounting Principle

Effective January 1, 2009, we adopted the new accounting standard which determines whether instruments granted in share-based payment transactions are participating securities. Under this standard, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share pursuant to the two-class method. Under the two-class method, earnings per share are determined for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. We have determined that our unvested phantom stock awards contain non-forfeitable rights to dividends and, therefore, are participating securities for purposes of this standard. Because the phantom stock awards do not participate in losses, they are antidilutive if we are in a loss position.

Effective January 1, 2009, we also adopted the new accounting standard regarding convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement. Because the Convertible Notes can be settled wholly or partly in cash upon conversion into our common stock, this standard requires us to account separately for the liability and equity components in a manner that reflects our nonconvertible debt borrowing rate when measuring interest cost of the Convertible Notes. The value assigned to the liability component was the estimated value of a similar debt issuance without the conversion feature as of the issuance date in December 2007. Transaction costs associated with issuing the instrument were allocated to the liability and equity components in proportion to the allocation of the original proceeds and were accounted for as debt issuance costs and equity issuance costs. In addition, recognizing the Convertible Notes as two separate components resulted in a tax basis difference associated with the liability component that represents a temporary difference. Because the liability component was valued exclusive of the conversion feature, the Convertible Notes were recorded at a discount reflecting the below-market coupon interest rate. This discount is accreted through additional interest expense to par value over the remaining expected life of the debt ending in 2012.

We applied both new standards retroactively to all periods presented as required.

(in thousands, except per share amounts)

22. Changes in Accounting Principle – (continued)

The following tables reflect the effects of adopting the standard on the relevant lines of our Consolidated Financial Statements for the periods presented:

	As Originally Reported	As Adjusted	Effects of Change
Consolidated Statements of Income			
For the Year Ended December 31, 2008:			
Interest expense(1)	$ 44,261	$ 49,299	$ 5,038
Income tax expense (benefit)(2)	73,874	71,920	(1,954)
Net income(3)	184,604	181,520	(3,084)
Net income (loss) attributable to Penn Virginia Corporation	124,168	121,084	(3,084)
Earnings per share attributable to Penn Virginia Corporation:			
Basic	$ 2.97	$ 2.89	$ (0.08)
Diluted	$ 2.95	$ 2.87	$ (0.08)
For the Year Ended December 31, 2007:			
Interest expense(1)	$ 37,419	$ 37,851	$ 432
Income tax expense (benefit)(2)	30,501	30,332	(169)
Net income(3)	81,073	80,810	(263)
Net income (loss) attributable to Penn Virginia Corporation	50,754	50,491	(263)
Earnings per share attributable to Penn Virginia Corporation:			
Basic	$ 1.33	$ 1.32	$ (0.01)
Diluted	$ 1.32	$ 1.31	$ (0.01)
Consolidated Balance Sheet			
As of December 31, 2008:			
Oil and gas properties(4)	$2,106,126	$2,107,128	$ 1,002
Other assets(5)	46,674	45,685	(989)
Long-term debt(6)	562,000	531,896	(30,104)
Deferred income taxes (noncurrent liability)(7)	359,677	371,925	12,248
Paid-in capital(8)	464,751	485,967	21,216
Retained earnings(9)	446,993	443,646	(3,347)
Consolidated Statements of Cash Flows			
For the Year Ended December 31, 2008:			
Cash flows from operating activities			
Net income (loss)	$ 184,604	181,520	$ (3,084)
Deferred income taxes	60,505	58,551	(1,954)
Other noncash adjustments	7,484	12,522	5,038
For the Year Ended December 31, 2007:			
Cash flows from operating activities			
Net income (loss)	$ 81,073	80,810	$ (263)
Deferred income taxes	23,340	23,171	(169)
Other noncash adjustments	4,961	5,393	432

(1) Represents additional interest expense that would have been recorded related to the debt discount had the accounting guidance been in place when the Convertible Notes were issued. This increase is partially

(in thousands, except per share amounts)

22. Changes in Accounting Principle – (continued)

offset by changes in capitalized interest and the amortization of debt issuance costs, which resulted from the separation of the debt and equity components of the Convertible Notes.

(2) The adjustment to income taxes is based on our effective tax rates.

(3) Net income (loss) includes noncontrolling interests.

(4) The impact on oil and gas properties is due to capitalized interest.

(5) The adjustment to Other assets reflects a decrease in debt issuance costs.

(6) The impact on Long-term debt is due to the unamortized discount balance of the Convertible Notes.

(7) The impact on deferred income taxes is due to the change in the tax basis of the liability component.

(8) The impact on paid-in capital balance is due to the equity component and related issuance costs as well as the change in deferred income taxes.

(9) The impact on retained earnings is due to the additional interest expense net of tax as discussed in footnote 1 above.

23. Earnings per Share

The following table provides a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2009	2008(1)	2007(1)
Net income (loss) attributable to common shareholders	$(114,643)	$121,084	$50,491
Less: Portion of subsidiary net income allocated to undistributed share-based compensation awards, net of taxes	(116)	(295)	(186)
	$(114,759)	$120,789	$50,305
Weighted-average shares, basic	43,811	41,760	38,061
Effect of dilutive securities(2)	—	271	297
Weighted-average shares, diluted	43,811	42,031	38,358
Net income (loss) per common share, basic	$ (2.62)	$ 2.89	$ 1.32
Net income (loss) per common share, diluted	$ (2.62)	$ 2.87	$ 1.31

(1) Adjusted for the adoption of changes in accounting principle with respect to earnings per share and convertible notes (see Note 22).

(2) For 2009, approximately 0.1 million potentially dilutive securities, including the Convertible Notes, stock options, restricted stock and phantom stock had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

24. Segment Information

Our operating segments represent components of our businesses about which separate financial information is available and is evaluated regularly by the chief operating decision maker, or decision-making group, in assessing performance. Our decision-making group consists of our Chief Executive Officer and other senior officers. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations and PVR's coal and natural resource management operations and PVR's natural gas midstream operations. Accordingly, our reportable segments are as follows:

- *Oil and Gas* — crude oil and natural gas exploration, development and production.

(in thousands, except per share amounts)

24. Segment Information – (continued)

- *PVR Coal and Natural Resource Management* — PVR's coal and natural resource management segment primarily involves the management and leasing of coal properties and the subsequent collection of royalties. Our coal reserves are primarily located in Kentucky, Virginia, West Virginia, Illinois and New Mexico. PVR also earns revenues from other land management activities, such as selling standing timber; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants; collection of oil and gas royalties; and coal from transportation, or wheelage fees.
- *PVR Natural Gas Midstream* — PVR's natural gas midstream segment is engaged in providing natural gas processing, gathering and other related services. PVR owns and operates natural gas midstream assets located in Oklahoma and Texas. PVR's natural gas midstream business derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for natural gas volumes and providing other related services. In addition, PVR owns a 25% member interest in Thunder Creek, a joint venture that gathers and transports CBM in Wyoming's Powder River Basin. PVR also owns a natural gas marketing business, which aggregates third-party volumes and sells those volumes into interstate pipeline systems and at market hubs accessed by various interstate pipelines.

The following table presents a summary of certain financial information relating to our segments for the periods presented:

	Revenues			Intersegment Revenues[1]		
	2009	2008	2007	2009	2008	2007
Oil and gas[2]	$235,084	$ 471,479	$304,790	$ (1,152)	$ (2,149)	$(1,549)
Coal and natural resource[3]	144,600	152,535	110,847	791	792	792
Natural gas midstream[4]	512,104	595,884	436,257	76,773	132,369	1,549
Eliminations and other	(76,651)	953	1,056	(76,412)	(131,012)	(792)
	$815,137	$1,220,851	$852,950	$ —	$ —	$ —

	Operating income (loss)			DD&A expense		
	2009	2008	2007	2009	2008	2007
Oil and gas[5]	$(175,993)	$170,576	$103,983	$150,429	$132,276	$ 87,223
Coal and natural resource[6]	87,528	96,296	68,811	31,330	30,805	22,690
Natural gas midstream[7]	20,774	18,946	48,914	38,905	27,361	18,822
Eliminations and other	(30,511)	(28,995)	(29,084)	2,703	1,794	788
	$ (98,202)	$256,823	$192,624	$223,367	$192,236	$129,523
Interest expense	(68,884)	(49,299)	(37,851)			
Derivatives	11,854	46,582	(47,282)			
Other	2,612	(666)	3,651			
Income tax (expense) benefit	75,252	(71,920)	(30,332)			
Net income (loss)	(77,368)	181,520	80,810			
Less: Net income attributable to noncontrolling interests	(37,275)	(60,436)	(30,319)			
Income (loss) attributable to Penn Virginia Corporation	$(114,643)	$121,084	$ 50,491			

(in thousands, except per share amounts)

24. Segment Information – (continued)

	Additions to property and equipment			Total assets at December 31,		
	2009	2008	2007	2009	2008	2007
Oil and gas	$203,678	$607,220	$512,473	$1,591,460	$1,727,373	$1,287,359
Coal and natural resource[8]	2,252	27,270	177,960	574,258	600,418	610,866
Natural gas midstream[9]	78,425	304,758	47,080	633,802	618,402	320,413
Eliminations and other	1,998	(60,162)	(24,003)	88,987	50,359	34,823
	$286,353	$879,086	$713,510	$2,888,507	$2,996,552	$2,253,461

(1) Intersegment revenues represent gas gathering and processing transactions between the PVR natural gas midstream segment and the oil and gas segment. Intersegment revenues also represent agent fees paid by the oil and gas segment to the PVR natural gas midstream segment for marketing certain natural gas production and rail car rental fees paid by a corporate affiliate to the PVR coal and natural resource management segment.

(2) Oil and gas segment revenues for the year ended December 31, 2007 excludes $31.0 million of gain related to the sale of royalty interests to PVR.

(3) The PVR coal and natural resource management segment's revenues for the years ended December 31, 2009, 2008 and 2007 include $1.7 million, $1.8 million and $1.8 million of equity earnings related to PVR's 50% interest in Coal Handling Solutions LLC.

(4) The PVR natural gas midstream segment's revenues for the years ended December 31, 2009 and 208 include $5.3 million and $2.4 million of equity earnings related to PVR's 25% member interest in Thunder Creek that PVR acquired in 2008 for $51.6 million. See Note 5 for a further description of this acquisition.

(5) Oil and gas segment's operating income for the years ended December 31, 2009, 2008 and 2007 includes impairments of oil and gas properties and other assets for $106.4 million, $20.0 million and $2.6 million, respectively. See Note 19.

(6) The PVR coal and natural gas midstream segment's operating income for the year ended December 31, 2009 includes an intangible asset impairment of $1.5 million.

(7) The PVR natural gas midstream segment's operating income for the year ended December 31, 2008 includes an impairment of goodwill for $31.8 million. See Notes 5 and 19.

(8) Total assets as of December 31, 2009, 2008 and 2007 for the PVR coal and natural resource management segment included equity investments of $21.0 million, $23.4 million and $25.6 million related to PVR's 50% interest in Coal Handling Solutions, LLC.

(9) Total assets as of December 31, 2009 and 2008 for the PVR natural gas midstream segment included equity investments of $59.8 million and $55.0 million related to PVR's 25% member interest in Thunder Creek that PVR acquired in 2008. Total assets as of December 31, 2007 for the PVR natural gas midstream segment included goodwill of $7.7 million.

Operating income is equal to total revenues less cost of midstream gas purchased, operating costs and expenses and DD&A expenses. Identifiable assets are those assets used in our operations in each segment.

For the year ended December 31, 2009, one third-party customer of the PVR natural gas midstream segment accounted for $109.5 million, or 13%, of our total consolidated net revenues, and two third-party customers of our oil and gas segment accounted for $58.2 million, or 7% of our total consolidated net revenues. For the year ended December 31, 2008, two third party customers of the PVR natural gas midstream segment accounted for $288.7 million, or 24%, of our total consolidated net revenues. For the year ended December 31, 2007, one customer of the PVR natural gas midstream segment accounted for $109.2 million, or 13%, of our total consolidated revenues. These customer concentrations may impact our

24. Segment Information – (continued)

results of operations, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We are not aware of any financial difficulties experienced by these customers.

Intercompany railcar rental revenues were $0.8 million for each of the years 2009, 2008 and 2007, respectively, and are included in the PVR coal and natural resource management segment. The offsetting railcar rental expense and the elimination of the revenue and expense are included in the corporate and other column of the preceding table.

The oil and gas segment and the PVR natural gas midstream segment are parties to a Master Services Agreement effective September 1, 2006. Pursuant to the Master Services Agreement, PVR's natural gas midstream segment will market all of the oil and gas segment's oil and gas production in Arkansas, Louisiana, Oklahoma and Texas for a fee equal to 1% of the net sales price (subject to specified limitations) received by the oil and gas segment for such production. The Master Services Agreement has a primary term of five years and automatically renews for additional one-year terms until terminated by either party. Under the Master Services Agreement, the oil and gas segment paid fees to the PVR natural gas midstream of $1.4 million, $3.0 million and $2.2 million for the years ended December 31, 2009, 2008 and 2007.

The PVR natural gas midstream segment and the oil and gas segment are parties to a natural Gas Gathering and Processing Agreement effective April 1, 2007. Pursuant to the Gas Gathering and Processing Agreement, the oil and gas segment and the PVR natural gas midstream segment have agreed that the PVR natural gas midstream segment will gather and process all of the oil and gas segment's current and future gas production in certain areas of the Bethany Field in East Texas and redeliver the NGLs to oil and gas segment for a $0.30/MMBtu service fee (with an annual CPI adjustment). The Gas Gathering and Processing Agreement has a primary term of 15 years and automatically renews for additional one year terms until terminated by either party. The PVR natural gas midstream segment began gathering and processing the oil and gas segment's gas in June 2008. For the years ended December 31, 2009 and 2008, the oil and gas segment paid the PVR natural gas midstream segment $4.0 million and $2.3 million in fees pursuant to the Gas Gathering and Processing Agreement.

From time to time, the oil and gas segment sells gas or NGLs to the PVR natural gas midstream segment at its Crossroads Plant, the PVR natural gas midstream segment transports them to the marketing location, and then resells such gas or NGLs to third parties. The sales price received by the oil and gas segment from the PVR natural gas midstream segment for such gas or NGLs equals the sales price received by the PVR natural gas midstream segment for such gas or NGLs from the third parties. For the years ended December 31, 2009 and 2008, the oil and gas segment received $72.5 million and $127.9 million from the PVR natural gas midstream segment in connection with such sales. For the years ended December 31, 2009 and 2008, the PVR natural gas midstream segment recorded $72.5 million and $127.9 million of natural gas midstream revenue and the same amounts for the cost of midstream gas purchased related to the purchase of natural gas from the oil and gas segment and the subsequent sale of that gas to third parties. The PVR natural gas midstream segment takes title to the gas prior to transporting it to third parties. These transactions do not impact the gross margin, nor do they impact operating income other than the fee collected earlier in the process.

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries

The Senior Notes are fully and unconditionally and joint and severally guaranteed by our oil and gas subsidiaries (collectively, the "Guarantor Subsidiaries"). The primary non-guarantor subsidiaries are PVG and PVR (collectively, the "Non-guarantor Subsidiaries"). As such, the Company is subject to the requirements Rule 3-10(f) of Regulation S-X of the Securities and Exchange Commission regarding financial statements of guarantors and issuers of registered guaranteed securities.

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

The condensed consolidating financial information below present the financial position, results of operations and cash flows of the Company, the Guarantor Subsidiaries and Non-guarantor Subsidiaries:

Balance Sheets

	As of December 31, 2009				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Assets					
Cash and cash equivalents	$ 76,074	$ 2,943	$ 19,314	$ —	$ 98,331
Accounts receivable	—	42,378	82,426	—	124,804
Inventory	—	10,372	1,832	—	12,204
Assets held for sale	—	38,282	—	—	38,282
Other current assets	3,311	16,510	10,124	(4,324)	25,621
Total current assets	79,385	110,485	113,696	(4,324)	299,242
Property and equipment, net	6,314	1,473,034	900,948	(27,938)	2,352,358
Investments in affiliates (equity method)	1,346,659	89,992	—	(1,436,651)	—
Other assets	22,785	7,874	210,438	(4,190)	236,907
Total assets	$1,455,143	$1,681,385	$1,225,082	$(1,473,103)	$2,888,507
Liabilities and shareholders' equity					
Accounts payable and accrued liabilities	$ 8,909	$ 55,278	$ 73,201	$ —	$ 137,388
Other current liabilities	—	9,220	11,251	(4,324)	16,147
Total current liabilities	8,909	64,498	84,452	(4,324)	153,535
Deferred income taxes	—	260,933	71,495	(4,190)	328,238
Long-term debt of PVR	—	—	620,100	—	620,100
Long-term debt of the Company	498,427	—	—	—	498,427
Other long-term liabilities	11,781	9,295	29,132	—	50,208
Penn Virginia Corporation's equity	936,026	1,346,659	89,992	(1,464,589)	908,088
Noncontrolling interests in subsidiaries	—	—	329,911	—	329,911
Total liabilities and shareholders' equity	$1,455,143	$1,681,385	$1,225,082	$(1,473,103)	$2,888,507

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Balance Sheets

	As of December 31, 2008				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Assets					
Cash and cash equivalents	$ —	$ —	$ 18,338	$ —	$ 18,338
Accounts receivable	—	75,962	73,279	—	149,241
Inventory	—	16,595	1,873	—	18,468
Other current assets	37,455	7,241	32,823	(48)	77,471
Total current assets	37,455	99,798	126,313	(48)	263,518
Property and equipment, net	8,255	1,637,832	895,247	(29,157)	2,512,177
Investments in affiliates (equity method)	1,574,758	268,314	—	(1,843,072)	—
Other assets	32,857	49	237,065	(49,101)	220,870
Total assets	$1,653,325	$2,005,993	$1,258,625	$(1,921,378)	$2,996,565
Liabilities and shareholders' equity					
Current maturities of long-term debt	$ 7,542	$ —	$ —	$ —	$ 7,542
Accounts payable and accrued liabilities	8,294	129,190	69,418	—	206,902
Other current liabilities	15,032	—	18,166	(48)	33,150
Total current liabilities	30,868	129,190	87,584	(48)	247,594
Deferred income taxes	11,868	409,158	—	(49,101)	371,925
Long-term debt of PVR	—	—	568,100	—	568,100
Long-term debt of the Company	531,896	—	—	—	531,896
Other long-term liabilities	10,433	6,775	37,400	—	54,608
Penn Virginia Corporation's equity	1,068,260	1,460,870	268,314	(1,872,229)	925,215
Noncontrolling interests in subsidiaries	—	—	297,227	—	297,227
Total liabilities and shareholders' equity	$1,653,325	$2,005,993	$1,258,625	$(1,921,378)	$2,996,565

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Income Statements

	Year Ended December 31, 2009				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Revenues	$ —	$ 235,084	$656,826	$(76,773)	$ 815,137
Cost of midstream gas purchased	—	—	406,583	(72,729)	333,854
Operating	—	55,699	35,111	(4,044)	86,766
Exploration	—	57,754	—	—	57,754
Taxes other than income	736	16,556	4,781	—	22,073
General and administrative	24,784	22,625	32,591	—	80,000
Depreciation, depletion and amortization	3,899	150,429	70,258	(1,219)	223,367
Impairments	—	106,415	1,511	—	107,926
Loss on sale of assets	—	1,599	—	—	1,599
Operating expenses	29,419	411,077	550,835	(77,992)	913,339
Operating income	(29,419)	(175,993)	105,991	1,219	(98,202)
Equity in earnings of subsidiaries	(93,753)	15,282	—	78,471	—
Interest expense and other	(45,752)	2,780	(23,300)	—	(66,272)
Derivatives	36,240	(4,672)	(19,714)	—	11,854
Income (loss) before income taxes and noncontrolling interests	(132,684)	(162,603)	62,977	79,690	(152,620)
Income tax benefit (expense)	16,822	68,850	(10,420)	—	75,252
Net income (loss)	(115,862)	(93,753)	52,557	79,690	(77,368)
Less net income attributable to noncontrolling interests	—	—	(37,275)	—	(37,275)
Net income (loss) attributable to Penn Virginia Corporation	$(115,862)	$ (93,753)	$ 15,282	$ 79,690	$(114,643)

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Income Statements

	Year Ended December 31, 2008				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Revenues	$ 3	$469,330	$881,737	$(130,219)	$1,220,851
Cost of midstream gas purchased	—	—	612,530	(127,909)	484,621
Operating	—	59,459	32,744	(2,312)	89,891
Exploration	—	42,436	—	—	42,436
Taxes other than income	984	23,336	4,266	—	28,586
General and administrative	24,210	21,285	28,999	—	74,494
Depreciation, depletion and amortization	3,388	132,276	58,189	(1,617)	192,236
Impairments	—	19,963	31,801	—	51,764
Operating expenses	28,582	298,755	768,529	(131,838)	964,028
Operating income	(28,579)	170,575	113,208	1,619	256,823
Equity in earnings of subsidiaries	134,321	28,259	—	(162,580)	—
Interest expense and other	(18,348)	—	(26,579)	—	(44,927)
Derivatives	29,745	—	16,837	—	46,582
Income (loss) before income taxes and noncontrolling interests	117,139	198,834	103,466	(160,961)	258,478
Income tax benefit (expense)	5,411	(64,513)	(14,771)	(1)	(73,874)
Net income (loss)	122,550	134,321	88,695	(160,962)	184,604
Less net income attributable to noncontrolling interests	—	—	(60,436)	—	(60,436)
Net income (loss) attributable to Penn Virginia Corporation	$122,550	$134,321	$ 28,259	$(160,962)	$ 124,168

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Income Statements

	Year Ended December 31, 2007				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Revenues	$ (305)	$334,521	$549,734	$ (31,000)	$852,950
Cost of midstream gas purchased	—	—	343,293	—	343,293
Operating	—	46,713	20,897	—	67,610
Exploration	—	28,608	—	—	28,608
Taxes other than income	780	17,847	3,096	—	21,723
General and administrative	25,282	16,283	25,418	—	66,983
Depreciation, depletion and amortization	985	87,223	41,541	(226)	129,523
Impairments	—	2,586	—	—	2,586
Operating expenses	27,047	199,260	434,245	(226)	660,326
Operating income	(27,352)	135,261	115,489	(30,774)	192,624
Equity in earnings of subsidiaries	111,729	27,942	—	(139,671)	—
Interest expense and other	(20,271)	13	(13,510)	—	(33,768)
Derivatives	(1,715)	—	(45,567)	—	(47,282)
Income (loss) before income taxes and noncontrolling interests	62,391	163,216	56,412	(170,445)	111,574
Income tax benefit (expense)	19,137	(51,487)	1,849	—	(30,501)
Net income (loss)	81,528	111,729	58,261	(170,445)	81,073
Less net income attributable to noncontrolling interests	—	—	(30,319)	—	(30,319)
Net income (loss) attributable to Penn Virginia Corporation	$ 81,528	$111,729	$ 27,942	$(170,445)	$ 50,754

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Statements of Cash Flows

	Year Ended December 31, 2009				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Net cash provided by (used in) operating activities	$ (15,213)	$ 132,946	$ 158,214	$ —	$ 275,947
Cash flows provided by (used in) investing activities:					
Investment in (distributions from) affiliates	101,778	160,359	—	(262,137)	—
Additions to property and equipment	(1,998)	(203,678)	(80,677)	—	(286,353)
Proceeds from the sale of assets and other	—	15,094	1,147	—	16,241
Cash flows provided by (used in) investing activities	99,780	(28,225)	(79,530)	(262,137)	(270,112)
Cash flows provided by (used in) financing activities:					
Distributions paid to noncontrolling interest holders	—	—	(78,171)	—	(78,171)
Net proceeds from (repayments of) borrowings	(339,542)	—	52,000	—	(287,542)
Net proceeds from issuance of senior notes	291,009	—	—	—	291,009
Net proceeds from the sale of PVG units	—	—	118,080	—	118,080
Net proceeds from issuance of equity	64,835	—	—	—	64,835
Capital contributions from (distributions to) affiliates	—	(101,778)	(160,359)	262,137	—
Other	(24,795)	—	(9,258)	—	(34,053)
Cash flows provided by (used in) financing activities	(8,493)	(101,778)	(77,708)	262,137	74,158
Net decrease in cash and cash equivalents	76,074	2,943	976	—	79,993
Cash and Cash equivalents – beginning of period	—	—	18,338	—	18,338
Cash and Cash equivalents – end of period	$ 76,074	$ 2,943	$ 19,314	$ —	$ 98,331

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Statements of Cash Flows

	Year Ended December 31, 2008				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Net cash provided by operating activities	$ (4,813)	$ 313,139	$ 75,448	$ —	$ 383,774
Cash flows provided by (used in) investing activities:					
Investment in (distributions from) affiliates	(217,542)	44,018	—	173,524	—
Additions to property and equipment	(1,588)	(607,220)	(270,278)	—	(879,086)
Proceeds from the sale of assets and other	—	32,521	998	—	33,519
Cash flows provided by (used in) investing activities	(219,130)	(530,681)	(269,280)	173,524	(845,567)
Cash flows provided by (used in) financing activities:					
Distributions paid to noncontrolling interest holders	—	—	(64,245)	—	(64,245)
Net proceeds from (repayments of) borrowings	210,000	—	—	—	210,000
Net proceeds from issuance of PVR units	—	—	138,141	—	138,141
Net proceeds from PVR long-term debt	—	—	156,000	—	156,000
Capital contributions from (distributions to) affiliates	—	217,542	(44,018)	(173,524)	—
Other	9,908	—	(4,200)	—	5,708
Cash flows provided by (used in) financing activities	219,908	217,542	181,678	(173,524)	445,604
Net increase (decrease) in cash and cash equivalents	(4,035)	—	(12,154)	—	(16,189)
Cash and Cash equivalents – beginning of period	4,035	—	30,492	—	34,527
Cash and Cash equivalents – end of period	$ —	$ —	$ 18,338	$ —	$ 18,338

25. Condensed Consolidating Financial Information of Guarantor Subsidiaries – (continued)

Statements of Cash Flows

	Year Ended December 31, 2007				
	Penn Virginia Corporation	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations	Consolidated
			(in thousands)		
Net cash provided by operating activities	$ 13,376	$ 174,655	$ 124,999	$ —	$ 313,030
Cash flows provided by (used in) investing activities:					
Investment in (distributions from) affiliates	(247,811)	29,840	—	217,971	—
Additions to property and equipment	(6,995)	(512,475)	(225,040)	31,000	(713,510)
Proceeds from the sale of assets and other	—	60,169	858	(31,000)	30,027
Cash flows provided by (used in) investing activities	(254,806)	(422,466)	(224,182)	217,971	(683,483)
Cash flows provided by (used in) financing activities:					
Distributions paid to noncontrolling interest holders	—	—	(49,739)	—	(49,739)
Net proceeds from (repayments of) borrowings	131,000	—	—	—	131,000
Net proceeds from equity issuance	135,441	—	—	—	135,441
Cash received for stock warrants sold	18,187	—	—	—	18,187
Cash paid for convertible note hedges	(36,817)	—	—	—	(36,817)
Net proceeds from PVR long-term debt	—	—	193,500	—	193,500
Capital contributions from (distributions to) affiliates	—	247,811	(29,840)	(217,971)	—
Other	(7,527)	—	597	—	(6,930)
Cash flows provided by (used in) financing activities	240,284	247,811	114,518	(217,971)	384,642
Net increase in cash and cash equivalents	(1,146)	—	15,335	—	14,189
Cash and Cash equivalents – beginning of period	5,181	—	15,157	—	20,338
Cash and Cash equivalents – end of period	$ 4,035	$ —	$ 30,492	$ —	$ 34,527

(in thousands, except per share amounts)

Supplemental Quarterly Financial Information (Unaudited)

2009	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
Revenues	$199,160	$183,917	$195,163	$236,897
Operating income (loss)[1]	$ (7,439)	$ (16,517)	$ (94,831)	$ 20,585
Income (loss) attributable to Penn Virginia Corp.	$ (7,209)	$ (22,183)	$ (79,900)	$ (5,351)
Earnings (loss) per share attributable to Penn Virginia Corporation [3]:				
Basic	$ (0.17)	$ (0.52)	$ (1.76)	$ (0.12)
Diluted	$ (0.17)	$ (0.52)	$ (1.76)	$ (0.12)
Weighted-average shares outstanding:				
Basic	41,922	42,798	45,427	45,434
Diluted	41,922	42,798	45,427	45,434
2008				
Revenues	$249,135	$360,414	$385,612	$225,690
Operating income (loss)[2]	$ 60,133	$106,224	$122,327	$ (31,861)
Income (loss) attributable to Penn Virginia Corp.	$ 3,194	$ (4,549)	$122,953	$ (514)
Earnings (loss) per share attributable to Penn Virginia Corporation [3]:				
Basic	$ 0.08	$ (0.11)	$ 2.94	$ (0.01)
Diluted	$ 0.08	$ (0.11)	$ 2.88	$ (0.01)
Weighted-average shares outstanding:				
Basic	41,558	41,740	41,881	41,907
Diluted	41,803	41,740	42,544	42,006

(1) Includes impairments of oil and gas assets of $1.2 million, 3.3 million, $4.4 million and $0.1 million during each of the four quarters of 2009, respectively. Includes impairments of $87.9 million and $9.5 million for oil and gas properties held for sale during the third and fourth quarters of 2009, respectively. Includes a $1.5 million impairment of one of PVR's equity investments during the fourth quarter of 2009 (see Note 19).

(2) Includes an impairment of goodwill for $31.8 million that was recorded during the fourth quarter of 2008 (see Note 19).

(3) The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following supplemental information regarding the oil and gas producing activities is presented in accordance with the requirements of the current oil and gas accounting standards. The amounts shown include our net working and royalty interest in all of our oil and gas operations.

(in thousands, except per share amounts)

Capitalized Costs Relating to Oil and Gas Producing Activities

	As of December 31,		
	2009	2008	2007
Proved properties	$ 353,386	$ 322,030	$ 280,795
Unproved properties	73,067	155,803	127,805
Wells, equipment and facilities	1,527,749	1,623,274	1,112,688
Support equipment	5,938	6,021	4,493
	1,960,140	2,107,128	1,525,781
Accumulated depreciation and depletion	(487,106)	(469,296)	(337,679)
Net capitalized costs	$1,473,034	$1,637,832	$1,188,102

During the years ended December 31, 2009, 2008 and 2007, an additional $0.4 million, $0.5 million and $0.5 million related to ARO assets were added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2009	2008	2007
Proved property acquisition costs	$ —	$ —	$ 88,174
Unproved property acquisition costs	14,996	93,110	18,817
Exploration costs	7,179	30,373	46,245
Development costs and other	149,625	518,213	367,012
Total costs incurred	$171,800	$641,696	$520,248

Results of Operations for Oil and Gas Producing Activities

The following table includes results solely from the production and sale of oil and gas and a non-cash charge for property impairments. It excludes corporate-related general and administrative expenses and gains or losses on property dispositions. The income tax expense is calculated by applying the statutory tax rates to the revenues after deducting costs, which include depletion allowances and giving effect to oil and gas related permanent differences and tax credits.

	Year Ended December 31,		
	2009	2008	2007
Revenues	$ 228,659	$436,622	$290,286
Production expenses	72,255	82,191	65,130
Exploration expenses	57,754	42,436	28,608
Depreciation and depletion expense	150,429	132,276	87,223
Impairment of oil and gas properties	106,415	19,963	2,586
	(158,194)	159,756	106,739
Income tax expense (benefit)	(61,221)	61,985	41,628
Results of operations	$ (96,973)	$ 97,771	$ 65,111

The combined depletion and accretion expense related to asset retirement that were recognized during 2009, 2008 and 2007 in DD&A expense was approximately $0.7 million, $0.4 million and $0.7 million.

Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the oil and gas segment's royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the three years ended December 31, 2009 were estimated by Wright & Company, Inc., utilizing data compiled by us.

All reserves are located in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years.

Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves are proved reserves expected to be recovered through new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. The proved undeveloped reserves included in our current estimates relate to wells that are forecasted to be drilled within the next five years.

Our Manager of Engineering if primarily responsible for overseeing the preparation of the Company's reserve estimate by our independent third party engineers, Wright & Company, Inc. The Manager of Engineering has over twenty-four years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The technical person primarily responsible for review of our reserve estimates at Wright & Company, Inc., meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

(in thousands, except per share amounts)

Proved Developed and Undeveloped Reserves	Natural Gas (MMcf)	Oil and Condensate (MBbl)	Total Equivalents (MMcfe)
December 31, 2006	457,246	4,910	486,706
Revisions of previous estimates	(19,554)	3,853	3,566
Extensions, discoveries and other additions(1)	137,634	6,547	176,915
Production	(37,802)	(461)	(40,569)
Purchase of reserves(2)	72,102	390	74,440
Sale of reserves in place	(21,363)	(19)	(21,476)
December 31, 2007	588,263	15,220	679,582
Revisions of previous estimates	(59,828)	(131)	(60,614)
Extensions, discoveries and other additions(3)	267,190	12,783	343,888
Production	(41,493)	(898)	(46,881)
Purchase of reserves	—	—	—
Sale of reserves in place	—	—	—
December 31, 2008	754,132	26,974	915,975
Revisions of previous estimates(4)	(110,349)	(8,442)	(160,995)
Extensions, discoveries and other additions(5)	180,448	9,203	235,666
Production	(43,337)	(1,277)	(51,000)
Purchase of reserves	—	—	—
Sale of reserves in place	(4,229)	(71)	(4,659)
December 31, 2009	776,665	26,387	934,987
Proved Developed Reserves:			
December 31, 2007	372,626	4,463	399,404
December 31, 2008	411,366	9,895	470,736
December 31, 2009	388,382	8,357	438,524

(1) Increased due to drilling 151 wells on locations which were not classified as proved undeveloped locations in our 2006 year-end reserve report and the addition of 229 new proved undeveloped locations as a result of our 2007 drilling activities.

(2) We purchased approximately 74.4 Bcfe of reserves, primarily in Oklahoma and East Texas.

(3) Increased due to the drilling of 158 wells on locations which were not classified as proved undeveloped locations in our 2007 year-end reserve report and the addition of 1,031 new proved undeveloped locations as a result of our 2008 drilling activities.

(4) We had downward revisions of 161 Bcfe which were primarily the result of the following: 1) downward revisions of 63.1 Bcfe due to price, 2) a downward revision of 27.1 Bcfe in Appalachia for the removal of proved undeveloped reserves, which resulted from wells that no longer met the reasonable certainty threshold, 3) downward revisions of 20.1 Bcfe for NGLs that we received in East Texas as a result of lower plant yields and 4) various downward revisions amounting to 50.7 Bcfe across our assets which were the result of well performance and the application of the new oil and gas reserve calculation methodology.

(5) We added 235.7 Bcfe due to the drilling of 13 wells on locations which were not classified as proved undeveloped locations in our 2008 year-end reserve report and the addition of 105 new proved undeveloped locations, primarily in the Gulf Coast and Mid-Continent regions, as a result of our 2009 drilling activities.

(in thousands, except per share amounts)

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves. Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period for 2009 and estimated future costs as of that fiscal year end to the estimated future production of proved reserves. For periods prior to 2009, future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved reserves. Natural gas prices were escalated only where existing contracts contained fixed and determinable escalation clauses. Contractually provided natural gas prices in excess of estimated market clearing prices were used in computing the future cash inflows only if we expect to continue to receive higher prices under legally enforceable contract terms. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year Ended December 31,		
	2009	2008	2007
Future cash inflows	$ 4,178,449	$ 5,031,678	$ 5,140,818
Future production costs	(1,300,235)	(1,588,959)	(1,496,057)
Future development costs	(888,493)	(924,219)	(667,118)
Future net cash flows before income tax	1,989,721	2,518,500	2,977,643
Future income tax expense	(491,832)	(567,779)	(727,561)
Future net cash flows	1,497,889	1,950,721	2,250,082
10% annual discount for estimated timing of cash flows	(973,118)	(1,221,320)	(1,278,172)
Standardized measure of discounted future net cash flows	$ 524,771	$ 729,401	$ 971,910

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2009	2008	2007
Sales of oil and gas, net of production costs	$(157,891)	$(355,552)	$(227,136)
Net changes in prices and production costs	(314,209)	(318,730)	277,245
Extensions, discoveries and other additions	138,482	233,603	241,497
Development costs incurred during the period	65,043	112,925	108,584
Revisions of previous quantity estimates	(158,844)	(93,346)	17,846
Purchases of minerals-in-place	—	—	69,179
Sale of minerals-in-place	—	—	(42,395)
Accretion of discount	90,796	126,114	78,744
Net change in income taxes	15,168	110,670	(106,398)
Other changes	116,825	(58,193)	(49,856)
Net increase (decrease)	(204,630)	(242,509)	367,310
Beginning of year	729,401	971,910	604,600
End of year	$ 524,771	$ 729,401	$ 971,910

The changes in standardized measure relating to sales of reserves are calculated using prices in effect as of the beginning of the period and changes in standardized measure relating to purchases of reserves are calculated using the average prices during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated future costs as of that fiscal year end. Accordingly, the changes in standardized measure for purchases and sales of reserves reflected above do not necessarily represent the economic reality of such transactions. See "Costs Incurred in Certain Oil and Gas Activities" earlier in this Note and our Consolidated Statements of Cash Flows.

Item 9 Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2009. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2009, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. This evaluation was completed based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2009, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has issued an attestation report on the internal control over financial reporting as of December 31, 2009, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B Other Information

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2009 which we did not disclose.

Part III

Item 10 Directors, Executive Officers and Corporate Governance

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11 Executive Compensation

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13 Certain Relationships and Related Transactions, and Director Independence

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14 Principal Accounting Fees and Services

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15 Exhibits, Financial Statement Schedules

The following documents are filed as exhibits to this Annual Report on Form 10-K:

(1)	Financial Statements — The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 89 of this Annual Report on Form 10-K.
(2.1)	Purchase and Sale Agreement dated as of December 23, 2009 by and between Penn Virginia Oil & Gas, L.P. and Hilcorp Energy I, L.P. as amended by Amendment and Supplement to Purchase and Sale Agreement dated January 29, 2010 (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on February 3, 2010).
(2.2)	Purchase and Sale Agreement dated as of December 23, 2009 by and between Hilcorp Energy I, L.P. and Penn Virginia Oil & Gas Corporation (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on February 3, 2010).
(3.1)	Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).
(3.1.1)	Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).
(3.1.2)	Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).
(3.1.3)	Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on June 12, 2007).
(3.2)	Amended and Restated Bylaws of Registrant (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on December 14, 2009).
(4.1)	Subordinated Indenture dated as of December 5, 2007 among Penn Virginia Corporation, as Issuer, Penn Virginia Holding Corp., Penn Virginia Oil & Gas Corporation, Penn Virginia Oil & Gas GP LLC, Penn Virginia Oil & Gas LP LLC, Penn Virginia MC Corporation, Penn Virginia MC Energy L.L.C., Penn Virginia MC Operating Company L.L.C. and Penn Virginia Oil & Gas, L.P., as Subsidiary Guarantors, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).
(4.1.1)	First Supplemental Indenture dated December 5, 2007 between Penn Virginia Corporation, as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).
(4.2)	Senior Indenture dated as of June 15, 2009, among Penn Virginia Corporation, as issuer, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2009).
(4.2.1)	First Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated as of June 15, 2009 among Penn Virginia Corporation, as issuer, the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(4.3)	Form of Note for 10.375% Senior Notes due 2016 (incorporated by reference to Annex A to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(10.1)	Credit Agreement dated as of November 18, 2009 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 20, 2009).

(10.2) Call Option Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.3) Call Option Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.4) Call Option Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation. (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K filed on December 5, 2007)

(10.5) Call Option Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.7 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.6) Warrant Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.7) Warrant Transaction Amendment dated December 3, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.9 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.8) Warrant Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.9) Warrant Transaction Amendment dated December 3, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.11 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.10) Warrant Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.11) Warrant Transaction Amendment dated December 3, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.10 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.12) Warrant Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.8 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.13) Warrant Transaction Amendment dated December 3, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.12 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.14) Omnibus Agreement dated October 30, 2001 among Penn Virginia Corporation, Penn Virginia Resource GP, LLC, Penn Virginia Operating Co., LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on November 14, 2001).

(10.15) Amendment No. 1 to Omnibus Agreement dated December 19, 2002 among the Penn Virginia Corporation, Penn Virginia Resource GP, LLC, Penn Virginia Operating Co., LLC and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.9 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2002).

(10.16) Units Purchase Agreement dated June 17, 2008 by and among Penn Virginia Resource LP Corp., Kanawha Rail Corp. and Penn Virginia Resource Partners, L.P. (incorporated by reference to Exhibit 10.1 to Penn Virginia Resource Partners, L.P.'s Current Report on Form 8-K filed on July 22, 2008).

(10.17)	Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.18)	Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.19)	Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.20)	Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.29 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007). *
(10.21)	Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.30 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.22)	Penn Virginia Corporation Sixth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 23, 2009).*
(10.22.1)	Amendment No. 1 to the Penn Virginia Corporation Sixth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on April 28, 2009).*
(10.23)	Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Sixth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.24)	Form of Agreement for Restricted Stock Awards under the Penn Virginia Corporation Sixth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.33 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.25)	Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation Sixth Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on February 23, 2009).*
(10.26)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.27)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.28)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.29)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.30)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Resource GP, LLC and Keith D. Horton (incorporated by reference to Exhibit 10.1 to Penn Virginia Resource Partners, L.P.'s Current Report on Form 8-K filed on October 22, 2008).*
(10.31)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.15 to Penn Virginia Resource Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008).*

(10.32)	Change of Location Severance Agreement dated November 5, 2008 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.8 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008).*
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.
(14.1)	Penn Virginia Corporation Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 to Registrant's Current Report on Form 8-K filed on July 27, 2009).
(21.1)	Subsidiaries of Penn Virginia Corporation.
(23.1)	Consent of KPMG LLP.
(23.2)	Consent of Wright & Company, Inc.
(31.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1)	Report of Wright & Company, Inc. dated February 21, 2010 concerning evaluation of oil and gas reserves.

* Management contract or compensatory plan or arrangement.

SIGNATURES

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

PENN VIRGINIA CORPORATION

March 1, 2010	By: /s/ Frank A. Pici Frank A. Pici Executive Vice President and Chief Financial Officer
March 1, 2010	By: /s/ Forrest W. McNair Forrest W. McNair Vice President and Controller

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

/s/ Robert Garrett Robert Garrett	Chairman of the Board and Director	March 1, 2010
/s/ John U. Clarke John U. Clarke	Director	March 1, 2010
/s/ Edward B. Cloues, II Edward B. Cloues, II	Director	March 1, 2010
/s/ A. James Dearlove A. James Dearlove	Director and President and Chief Executive Officer	March 1, 2010
/s/ Keith D. Horton Keith D. Horton	Director and Executive Vice President	March 1, 2010
/s/ Marsha R. Perelman Marsha R. Perelman	Director	March 1, 2010
/s/ William H. Shea, Jr. William H. Shea, Jr.	Director	March 1, 2010
/s/ Philippe van Marcke de Lummen Philippe van Marcke de Lummen	Director	March 1, 2010
/s/ Gary K. Wright Gary K. Wright	Director	March 1, 2010

Exhibit 12.1

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges Calculation
(in thousands, except ratios)

	Year Ended December 31,				
	2005	2006	2007	2008	2009
Earnings					
Pre-tax income *	$ 130,918	$ 167,080	$ 106,386	$ 250,506	$ (158,103)
Fixed charges	20,755	31,313	47,159	59,672	80,903
Total Earnings	$ 151,673	$ 198,393	$ 153,545	$ 310,178	$ (77,200)
Fixed Charges					
Interest expense	$ 18,815	$ 27,984	$ 41,841	$ 52,010	$ 72,423
Rental Interest Factor	1,940	3,329	5,318	7,662	8,480
Total Fixed Charges	$ 20,755	$ 31,313	$ 47,159	$ 59,672	$ 80,903
Ratio of Earnings to Fixed Charges	**7.3x**	**6.3x**	**3.3x**	**5.2x**	**

* Includes cash distributions from equity affiliates and excludes equity earnings from affiliates. Also excludes capitalized interest.

** During 2009, earnings were deficient by $158,103 with respect to the coverage of fixed charges.

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C.	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware
Kanawha Rail Corp.	Virginia
Penn Virginia Resource GP Corp.	Delaware
Penn Virginia Resource LP Corp.	Delaware
Penn Virginia Equities Corporation	Delaware
PVG GP, LLC	Delaware
Penn Virginia GP Holdings, L.P.	Delaware
Penn Virginia Resource GP, LLC	Delaware
Penn Virginia Resource Partners, L.P.	Delaware
Penn Virginia Operating Co., LLC	Delaware
PVR Finco LLC	Delaware
Penn Virginia Resource Finance Corporation	Delaware
Fieldcrest Resources LLC	Delaware
K Rail LLC	Delaware
Loadout LLC	Delaware
Toney Fork LLC	Delaware
Suncrest Resources LLC	Delaware
Coal Handling Solutions LLC	Delaware
Kingsport Handling LLC	Delaware
Maysville Handling LLC	Delaware
Covington Handling LLC	Delaware
PVR Midstream LLC	Delaware
PVR Gas Resources, LLC	Delaware
Connect Energy Services, LLC	Delaware
Connect Gas Pipeline LLC	Delaware
PVR Cherokee Gas Processing LLC	Oklahoma
PVR East Texas Gas Processing LLC	Delaware
PVR Gas Processing LLC	Oklahoma
PVR Hamlin, LLC	Delaware
PVR Natural Gas Gathering LLC	Oklahoma
PVR North Texas Gas Gathering, LLC	Delaware
PVR Oklahoma Natural Gas Gathering LLC	Oklahoma

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statements on Form S-8 (No. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, and 333-159304) and Form S-3 (No. 333-143852, 333-159890) of Penn Virginia Corporation (the "Company") of our reports dated March 1, 2010, with respect to the consolidated balance sheets of the Company as of December 31, 2009 and 2008, and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009, and the effectiveness of internal control over financial reporting as of December 31, 2009, which reports appear in the December 31, 2009 annual report on Form 10-K of the Company.

/s/ KPMG LLP

Houston, Texas
March 1, 2010

Exhibit 23.2

CONSENT OF WRIGHT & COMPANY, INC. [OPEN]

As independent oil and gas consultants, Wright & Company, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-59647, 333-96463, 333-82274, 333-96465, 333-103455, 333-143514, 333-82304 and 333-159304) and Form S-3 (File Nos. 333-143852 and 333-159890) of Penn Virginia Corporation of information from our reserves report dated February 21, 2010 entitled "SUMMARY REPORT Evaluation of Oil and Gas Reserves to the Interests of Penn Virginia Oil & Gas Corporation, Penn Virginia Oil & Gas, L.P. and Penn Virginia MC Energy L.L.C. in Certain Properties in Various States Pursuant to the Requirements of the Securities and Exchange Commission Effective January 1, 2009 and all references to our firm included in or made a part of the Penn Virginia Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about March 1, 2010.

WRIGHT & COMPANY, INC.

By: /s/ D. RANDALL WRIGHT
D. Randall Wright
President

Brentwood, Tennessee
February 21, 2010

Exhibit 31.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, A. James Dearlove, President and Chief Executive Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: March 1, 2010

/S/ A. JAMES DEARLOVE
A. James Dearlove
President and Chief Executive Officer

Exhibit 31.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Frank A. Pici, Executive Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: March 1, 2010

/S/ FRANK A. PICI
Frank A. Pici
Executive Vice President and Chief Financial Officer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. James Dearlove, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2010

/S/ A. JAMES DEARLOVE
A. James Dearlove
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Frank A. Pici, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2010 By: /S/ FRANK A. PICI

Frank A. Pici
Executive Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

February 21, 2010

Penn Virginia Oil & Gas Corporation
Three Radnor Corporate Center
100 Matsonford Road, Suite 300
Radnor, PA 19087

ATTENTION: Mr. Frank E. Falbo, Jr.

SUBJECT: Evaluation of Oil and Gas Reserves
To the Interests of Penn Virginia Oil & Gas Corporation
In Certain Properties Located in Various States
Pursuant to the Requirements of the
Securities and Exchange Commission
Effective January 1, 2010
Jobs 09.1128, 09.1129 and 09.1130

At the request of Penn Virginia Oil & Gas Corporation (PVOG), Wright & Company, Inc. (Wright) has performed an evaluation to estimate proved reserves and associated cash flow and economics from certain properties to the subject interests. This evaluation was authorized by Mr. Frank E. Falbo, Jr. of PVOG. Projections of the reserves and cash flow to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered applicable at the effective date and are pursuant to the financial reporting requirements of the Securities and Exchange Commission (SEC). It is the understanding of Wright that the purpose of this evaluation is for inclusion in relevant registration statements or other filings to the SEC. The following is a summary of the results of the evaluation effective January 1, 2010.

	Proved Developed				
Penn Virginia Oil & Gas Corporation SEC Parameters	**Producing (PDP)**	**Nonproducing (PDNP)**	**Total Proved Developed (PDP & PDNP)**	**Total Proved Undeveloped (PUD)**	**Total Proved (PDP, PDNP & PUD)**
Net Reserves to the Evaluated Interests					
Oil, Mbbl:	2,941.611	567.183	3,508.794	8,008.678	11,517.472
Gas, MMcf:	356,231.688	32,150.756	388,382.469	388,282.750	776,665.188
NGL, Mbbl:	3,624.026	1,224.167	4,848.194	10,021.224	14,869.418
Gas Equivalent, MMcfe (6 Mcf = 1 Bbl)	395,625.510	42,898.856	438,524.397	496,462.162	934,986.528
Cash Flow (BTAX), M$					
Undiscounted:					
Discounted at 10%	1,054,235.750	77,526.070	1,131,761.875	857,960.938	1,989,722.625
Per Annum:	526,392.312	30,308.098	556,700.125	131,466.109	688,166.625

It should be noted that some minor differences between the total summaries may exist due to rounding techniques in the ARIES™ software program.

The properties evaluated in this report are contained in PVOG's wholly owned subsidiaries of Penn Virginia Oil & Gas Corporation (Eastern Region), Penn Virginia Oil & Gas, L.P. (Gulf Coast Region) and Penn Virginia MC Energy, LLC (Mid-Continent Region). The Eastern Region includes properties located in Kentucky, Mississippi, Virginia, and West Virginia. The Gulf Coast Region includes properties located in Louisiana and Texas. The Mid-Continent Region includes properties in North Dakota, Oklahoma, and Texas. According to PVOG, the total proved reserves included in this evaluation represent approximately 100 percent of the reported total proved reserves of PVOG.

Proved oil and gas reserves are those quantities of oil and gas which can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. As specified by the SEC regulations, when calculating economic producibility, the base product price must be the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the prior 12-month period. The benchmark base prices used for this evaluation were $3.866 per Million British thermal units (MMBtu) for natural gas at Henry Hub, LA and $61.18 per barrel for West Texas Intermediate oil at Cushing, OK. These benchmark prices were adjusted for energy content, quality and basis differential, as appropriate. Prices for oil and gas were held constant for the life of the properties.

Oil and other liquid hydrocarbons are expressed in thousands of United States (U.S.) barrels (Mbbl), one barrel equaling 42 U.S. gallons. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. No adjustment of the individual gas volumes to a common pressure base has been made.

Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, standard state and county taxes, operating expenses, and investments as applicable. The cash flow is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. The cash flow (BTAX) was discounted at an annual rate of 10.00 percent (PCT) in accordance with the reporting requirements of the SEC.

The estimates of reserves contained in this report were determined by acceptable industry methods and to the level of detail that Wright deemed appropriate. Where sufficient production history and other data were available, reserves for producing properties were determined by extrapolation of historical production or sales trends. Analogy to similar producing properties was used for development projects and for those properties that lacked sufficient production history to yield a definitive estimate of reserves. When appropriate, Wright may have also utilized volumetric calculations and log correlations in the determination of estimated ultimate recovery (EUR). These calculations are often based upon limited log and/or core analysis data and incomplete reservoir fluid and rock formation data. Since these limited data must frequently be extrapolated over an assumed drainage area, subsequent production performance trends or material balance calculations may cause the need for significant revisions to the estimates of reserves.

Oil and gas reserves were evaluated for the proved developed producing (PDP), proved developed nonproducing (PDNP) and proved undeveloped (PUD) reserves categories. The summary classification of total proved reserves combines the PDP, PDNP and PUD categories. In preparing this evaluation, no attempt has been made to quantify the element of uncertainty associated with any category. Reserves were assigned to each category as warranted. Wright is not aware of any local, state, or federal regulations that would preclude PVOG from continuing to produce from currently active wells or to fully develop those properties included in this report.

There are significant uncertainties inherent in estimating reserves, future rates of production and the timing and amount of future costs. Oil and gas reserves estimates must be recognized as a subjective process that cannot be measured in an exact way and estimates of others may differ materially from those of Wright. The accuracy of any reserves estimate is a function of quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates or changes in the analogous properties may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that ultimately are recovered.

All data utilized in the preparation of this report were provided by PVOG. No inspection of the properties was made as this was not considered to be within the scope of this evaluation. Wright has not independently verified the accuracy and completeness of information and data furnished by PVOG with respect to ownership interests, oil and gas production or sales, historical costs of operation and development, product prices, or agreements relating to current and future operations and sales of production. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by PVOG with regard to product pricing, appropriate adjustments, lease operating expenses, and capital investments for drilling the undeveloped locations. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. In accordance with the requirements of the SEC, all operating costs were held constant for the life of the properties.

No consideration was given in this report to potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this evaluation for potential liability for restoration and to clean up damages, if any, caused by past or future operating practices.

Wright is an independent petroleum consulting firm founded in 1988 and does not own any interests in the oil and gas properties covered by this report. No employee, officer, or director of Wright is an employee, officer, or director of PVOG nor does Wright, or any of its employees have direct financial interest in PVOG. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report.

This report is solely for the information of PVOG and for the information and assistance of its independent public accountants in connection with their review of and report upon the financial statements of PVOG and for reporting disclosures as required by the SEC. Notwithstanding, Wright understands and authorizes that this estimation of reserves may be included along with certain financial presentations on behalf of PVOG. This report should not be used, circulated or quoted for any other purpose without the express written consent of the undersigned, an officer of Wright, or except as required by law.

The professional qualifications of the petroleum consultants responsible for the evaluation of the reserves and economics information discussed in this report meet the standards of Reserves Auditor as defined in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* as promulgated by the Society of Petroleum Engineers.

It has been a pleasure to serve you by preparing this evaluation. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.

By: /s/ D. Randall Wright

D. Randall Wright
President

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Corporate Information

DIRECTORS

ROBERT GARRETT [1,2]
Chairman of the Board; Director of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P.; President of Robert Garrett & Sons, Inc.; Founder and former Managing Director of AdMedia Partners, Inc.

JOHN U. CLARKE
President of Concept Capital Group, Inc.; former Chairman and Chief Executive Officer of NATCO Group Inc.; former Managing Director of SCF Partners; former Chief Financial Officer of Dynegy, Inc. and Cabot Oil & Gas Corp.

EDWARD B. CLOUES, II [2,3]
Chairman and Chief Executive Officer of K-Tron International, Inc.; Director of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

A. JAMES DEARLOVE
President and Chief Executive Officer; Chairman of PVG GP, LLC and Penn Virginia Resource GP, LLC

KEITH D. HORTON
Executive Vice President; Co-President and Chief Operating Officer – Coal of Penn Virginia Resource GP, LLC

MARSHA R. PERELMAN [1,3]
Chief Executive Officer of Woodforde Management, Inc. and Director of Penn Virginia Resource GP, LLC

WILLIAM H. SHEA, JR. [2]
Chief Executive Officer and President of PVG GP, LLC; Chief Executive Officer of Penn Virginia Resource GP, LLC; Former Chairman, President and Chief Executive Officer, Buckeye GP LLC, the general partner of Buckeye Partners, L.P.

PHILIPPE VAN MARCKE DE LUMMEN [1]
President and Secretary of Universitas, Ltd.; Advisor to Cheniere Energy, Inc., and former President and Chief Executive Officer of Tractebel LNG Ltd.

GARY K. WRIGHT [2,3]
Consultant; former President of LNB Energy Advisors; former Southwest Managing Director for Chase Manhattan Bank Global Oil and Gas Group; former Manager of Chemical Bank Worldwide Energy Group

MANAGEMENT

A. JAMES DEARLOVE
President and Chief Executive Officer

FRANK A. PICI
Executive Vice President and Chief Financial Officer

H. BAIRD WHITEHEAD
Executive Vice President and Chief Operating Officer; President, Penn Virginia Oil & Gas Corporation

NANCY M. SNYDER
Executive Vice President and Chief Administrative Officer, General Counsel and Corporate Secretary

KEITH D. HORTON
Executive Vice President; Co-President, Penn Virginia Resource GP, LLC

RONALD K. PAGE
Vice President; Co-President, Penn Virginia Resource GP, LLC

FORREST W. MCNAIR
Vice President and Controller

DANA G WRIGHT
Vice President, Business Planning

STEVEN A. HARTMAN
Vice President and Treasurer

JAMES F. MODZELEWSKI
Vice President and Assistant General Counsel

PATRICK J. UDOVICH
Vice President, Human Resources

JAMES W. DEAN
Vice President, Corporate Development

JOHN A. BROOKS
Vice President, Mid-Continent Region

JAMES D. MCKINNEY
Vice President, Eastern Region

MICHAEL W. MOONEY
Vice President, Gulf Coast Region

ANNUAL MEETING

PENN VIRGINIA CORPORATION'S ANNUAL MEETING WILL BE HELD 10 A.M., MAY 5, 2010
Marriott Philadelphia West
111 Crawford Avenue
West Conshohocken, PA 19428
(610) 941-5600 phone

TRANSFER AGENT AND REGISTRAR

AMERICAN STOCK TRANSFER AND TRUST COMPANY
Mailing Address:
59 Maiden Lane
New York, NY 10038
(800) 937-5449 phone
(718) 236-2641 fax

(1) Member of the Nominating and Governance Committee
(2) Member of the Compensation and Benefits Committee
(3) Member of the Audit Committee

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PENN VIRGINIA CORPORATION

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green ANNUAL REPORT

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Penn Virginia Corporation saved the following resources by producing this Green Publication:

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