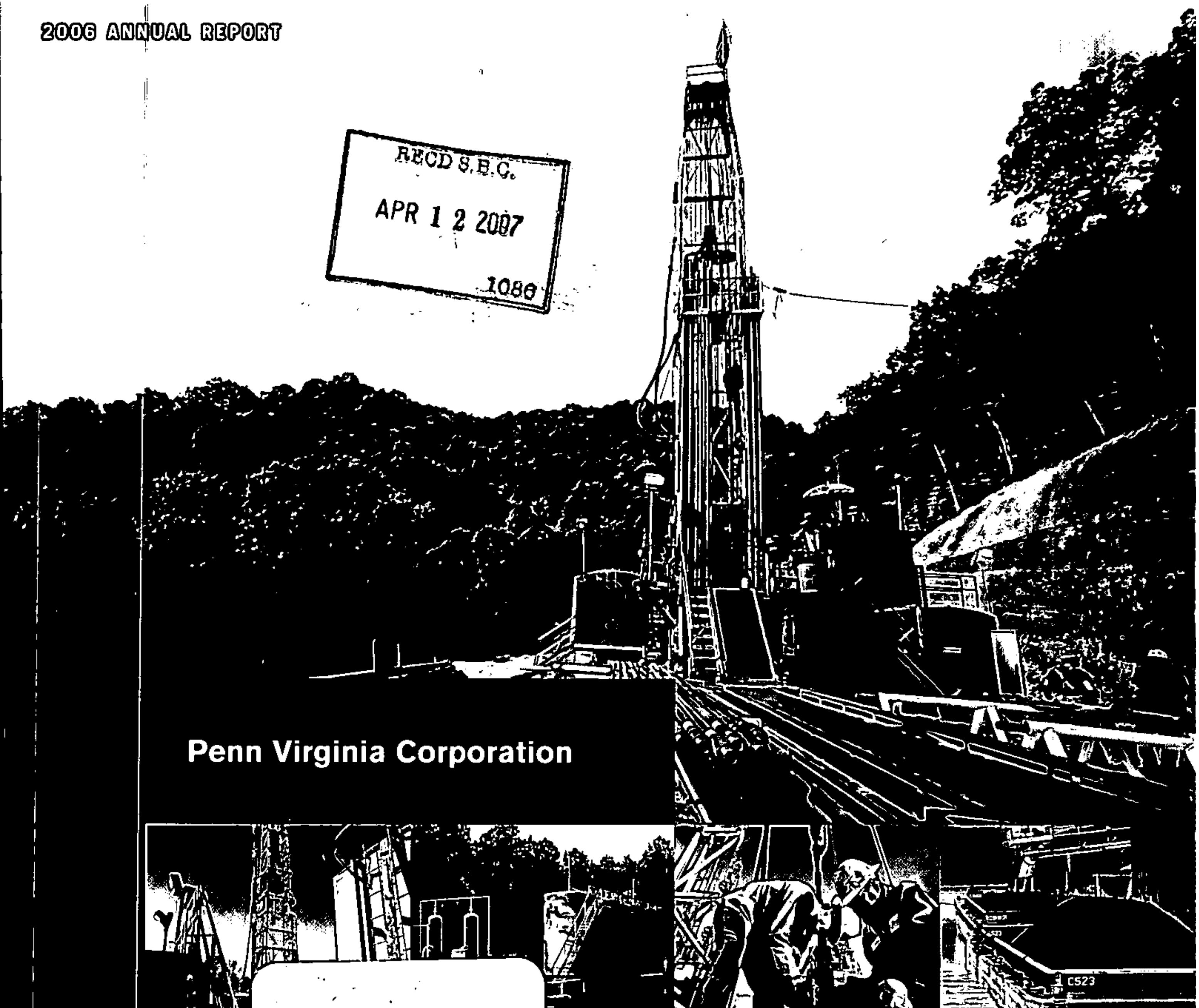
2006 ANNUAL REPORT



Penn Virginia Corporation

Unlocking Unique Value

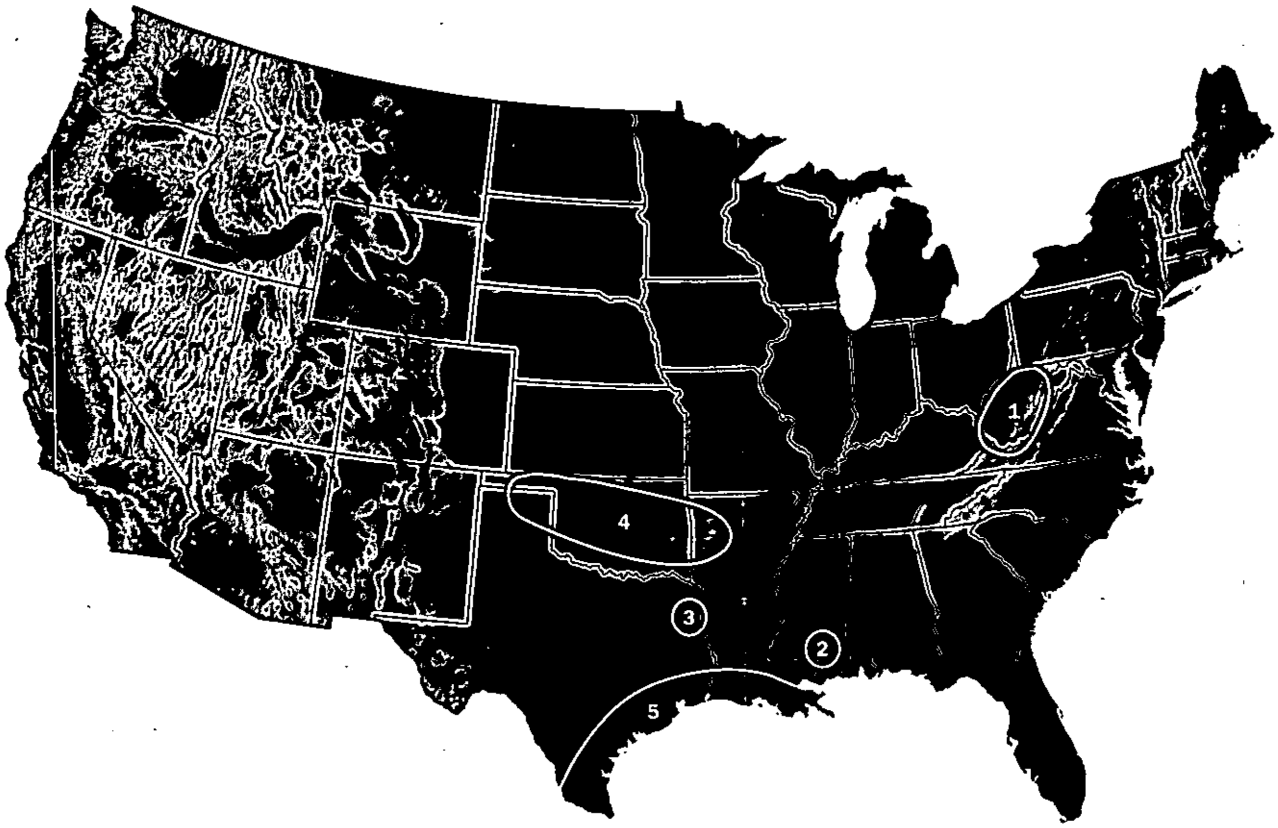
Headquartered in Radnor, PA, Penn Virginia Corporation (NYSE: PVA) is an independent natural gas and oil company focused on the acquisition, exploration, development and production of natural gas reserves. PVA also owns approximately 82 percent of Penn Virginia GP Holdings, L.P. (NYSE: PVG), the owner of the general partner and the largest unitholder of Penn Virginia Resource Partners, L.P. (NYSE: PVR), a manager of coal properties and related assets and the operator of a midstream natural gas gathering and processing business. For more information about PVA, visit the Company's website at www.pennvirginia.com.

► Financial Highlights

In millions except per share data	2006	2005	2004	2003	2002
Financial Data					
Net revenues[1]	$ 419.3	$ 370.0	$ 228.4	$ 181.3	$ 111.0
Operating income	170.5	162.0	80.8	62.1	30.8
Net income	75.9	62.1	33.4	28.5	12.1
Net cash flows provided by operating activities	275.8	231.4	146.4	109.7	65.8
Common Share Data[2]					
Net income, basic ($/share)	$ 4.06	$ 3.35	$ 1.82	$ 1.59	$ 0.68
Net Income, diluted ($/share)	$ 4.02	$ 3.31	$ 1.81	$ 1.58	$ 0.67
Dividends paid ($/share)	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.45
Weighted average shares outstanding, diluted	18.9	18.7	18.5	18.1	17.9
Capitalization					
Long-term debt, excluding current portion	$ 428.2	$ 325.8	$ 188.9	$ 154.3	$ 106.9
Minority interest in subsidiaries	438.4	313.5	182.9	190.5	192.8
Shareholder's equity	382.4	310.3	252.9	211.6	188.0
Total capitalization	1,249.0	949.6	624.7	556.4	487.7
Long-term debt as percent of total capitalization	34%	34%	30%	28%	22%
Production Data					
Total oil and gas production (Bcfe)	31.3	27.4	24.6	23.8	20.8
Natural gas (Bcf)	29.0	25.6	22.1	20.1	18.7
Oil and condensate (MBbl)	382	302	396	625	349
Daily production (MMcfe)	85.6	75	66.8	65.2	57.0
Coal produced by lessees (millions of tons)	32.8	30.2	31.2	26.5	14.3
Daily plant inlet volumes (MMcf)[3]	153	127	—	—	—
Realized Prices and Margins					
Oil and condensate ($/Bbl)	$ 55.59	$ 45.67	$ 33.75	26.91	$ 23.63
Natural gas ($/Mcf)	7.35	8.31	6.27	5.31	3.35
Coal royalties ($/ton)	2.99	2.74	2.23	1.90	2.20
Midstream processing margin ($/Mcf)	1.22	1.15	—	—	—
Estimated Reserves					
Total proved oil and gas reserves (Bcfe)	487	377	354	323	273
Coal (millions of recoverable tons)	765	689	558	588	615

(1) 2005 and 2006 revenues are shown net of cost of gas purchased.
(2) Amounts per common share in 2001 through 2003 have been adjusted for the effect of a two-for-one stock split effective on June 3, 2004.
(3) Natural gas midstream results from date of Cantera acquisition effective March 3, 2005.

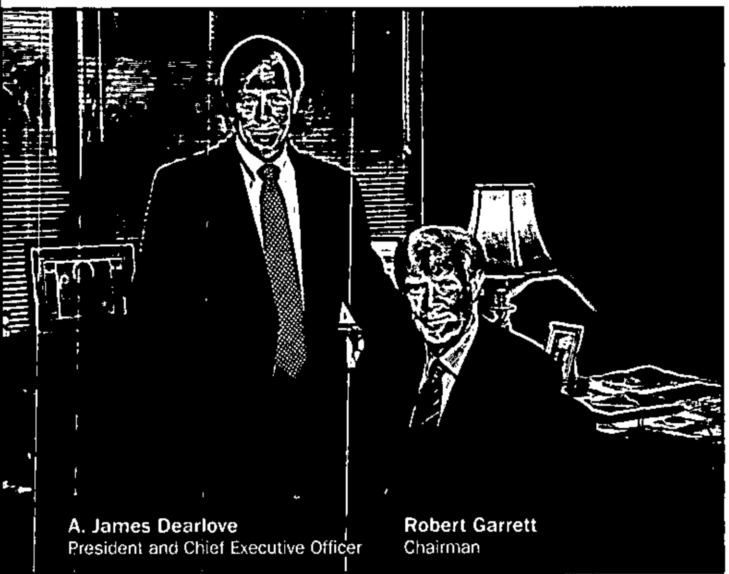
► Core Oil & Gas Producing Areas



1. **Appalachia** - Conventional and Horizontal CBM (HCBM) Development/Devonian Shale Potential
2. **Mississippi/Selma Chalk** - Selma Chalk Development
3. **East Texas/Cotton Valley** - Cotton Valley Development/Bossier Potential
4. **Mid-Continent** - Hartshorne HCBM and Granite Wash Development/Fayetteville Shale Exploration
5. **Gulf Coast** - Onshore Conventional Oil and Gas Exploration and Development

► 2006 Key Events

- Record operating and financial results from the oil and gas exploration and production, coal land management and natural gas midstream businesses
- Record net income of $75.9 million and cash flow from operating activities of $275.8 million
- Oil and gas production increased 14 percent to 31.3 Bcfe, or 85.6 MMcfe per day
- Oil and gas proved reserves increased 29 percent to 487 Bcfe, replacing 454 percent of 2006 production
- Approximately $266 million of oil and gas exploration and development capital expenditures to drill a company-record 210 (151.8 net) wells and 200 (146.1 net), or 95 percent, wells were successful
- $72 million Mid-Continent acquisition in June 2006 established a new core area for oil and gas production, development and exploration
- PVR lessee coal production increased nine percent to 32.8 million tons and natural gas midstream inlet volumes increased 44 percent to 56.0 Bcf, or 153 MMcf per day
- PVR coal reserves increased 11 percent to 765 million tons, primarily as the result of three reserve acquisitions
- Completed the initial public offering of Penn Virginia GP Holdings, L.P. (NYSE: PVG) in December, creating a publicly-traded entity to own the general partner, incentive distribution rights and an approximate 42 percent limited partner interest in PVR



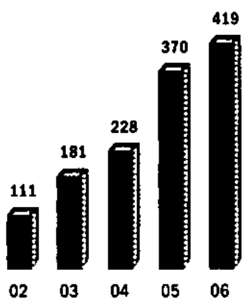
A. James Dearlove
President and Chief Executive Officer

Robert Garrett
Chairman

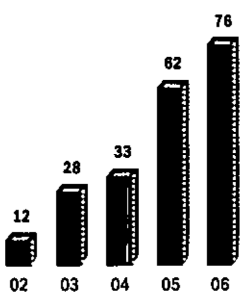
► Dear Fellow Shareholders

2006 was a year of major accomplishments for Penn Virginia Corporation (PVA). Our oil and gas (E&P) business achieved record levels of production and reserves. Penn Virginia Resource Partners, L.P. (PVR), a coal and natural gas midstream MLP which we control, set financial and operational records. With the December launch of Penn Virginia GP Holdings, L.P. (PVG) we established the market value of our holdings in PVG.

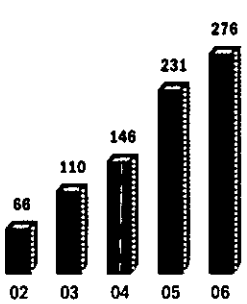
NET REVENUES
(Dollars in millions)



NET INCOME
(Dollars in millions)



CASH FLOW FROM OPERATIONS
(Dollars in millions)



We are pleased to report that 2006 was another record year for PVA operationally and financially. We set new company records in a number of categories, including:

- Oil and natural gas production increased 14 percent to a record 31.3 Bcfe
- Proved oil and gas reserves were up 29 percent to a record 487 Bcfe, with reserve replacement of 454 percent
- Revenues, net of the cost of gas purchased in our natural gas midstream segment, increased 13 percent over 2005 to a record $419.3 million
- Operating income increased five percent over 2005 to a record $170.5 million
- Net income increased 22 percent to a record $75.9 million
- Net cash provided by operating activities grew 19 percent to a record $275.8 million

During 2006, E&P expenditures, excluding acquisitions, were $266 million and resulted in record production and proved reserve levels for 2006. Increases in production and reserves came primarily from the east Texas Cotton Valley play and the Selma Chalk play in Mississippi, along with contributions from our newly acquired Mid-Continent operations.

In June 2006, we added a new "platform" area for E&P in the Arkoma and Anadarko Basins in the Mid-Continent region with a $72 million acquisition of 43 Bcfe of proved reserves. We commenced a horizontal coalbed methane drilling program in eastern Oklahoma during 2006, a development program we will expand in 2007, along with the Fayetteville Shale and Granite Wash plays in Arkansas and western Oklahoma, respectively. The Mid-Continent region has been a prolific natural gas and oil production area and we believe it will present future growth opportunities from acquisitions, exploration and development.

In December, we successfully completed an initial public offering of 18 percent of Penn Virginia GP Holdings, L.P. (NYSE: PVG) which holds our ownership interests in PVR.

PVG is a new publicly traded limited partnership formed to hold all of our interests in PVR. These consist of PVR's two percent general partner interest, approximately 42 percent of PVR's limited partner units and all of the PVR incentive distribution rights (IDRs). We believe the IPO of PVG will make it easier for analysts and investors to determine the value of our interests in PVR and thereby to more easily value each segment of the Company. Our commitment to the continued success of PVR was demonstrated by our investment of proceeds from PVG's IPO in additional limited partner units of PVR, thereby allowing PVR to repay debt to facilitate future growth. The distributions we expect from PVG will be an important source of cash to redeploy into our E&P activities.

In our coal land management business, we expanded coal reserves by 96 million tons to 765 million tons, replacing 332 percent of the record 32.8 million tons produced by lessees during 2006. In addition, we saw average coal royalty rates increase by nine percent to $2.99 per ton during 2006. Driving the growth in production and reserves were acquisitions in Central Appalachia and the Illinois Basin during 2005.

During its first full year of operations, our natural gas midstream business experienced a 44 percent increase in inlet volumes and a 52 percent increase in the gross midstream processing margin compared to the ten-month period in 2005. An acquisition of additional natural gas gathering capacity in June 2006 as well increased volumes from existing producing fields contributed to the record results.

Going forward, we expect to continue to expand all of these businesses. Our focus in the oil and gas business will be to continue to capitalize on our expertise in unconventional plays. Our 2007 oil and gas business capital budget is $334 million, a 26 percent increase over the $266 million of capital expenditures in 2006, excluding the Mid-Continent acquisition. Approximately 84 percent of this amount is earmarked to develop reserves in our four core areas of east Texas, Appalachia, Mid-Continent and Mississippi. Exploration spending will focus on our Gulf Coast prospect areas in south Louisiana and south Texas, which we believe provide the potential for meaningful reserve and production additions, and on finding new unconventional development plays in other basins to increase our inventory of low-risk development projects. We will also continue to expand the coal and midstream businesses at PVR through acquisitions and organic growth. While acquisitions are not explicitly budgeted, we continue to look for acquisition opportunities in all three major business segments.

PVA's tag line, "Unique in Energy," derives from our exposure to three diverse energy segments. We are committed to growth in each of these areas as well as to finding ways to exploit the synergies among them. As always, we greatly appreciate the hard work and dedication of Penn Virginia's employees and the continued loyalty and support of our shareholders.

Robert Garrett
Chairman

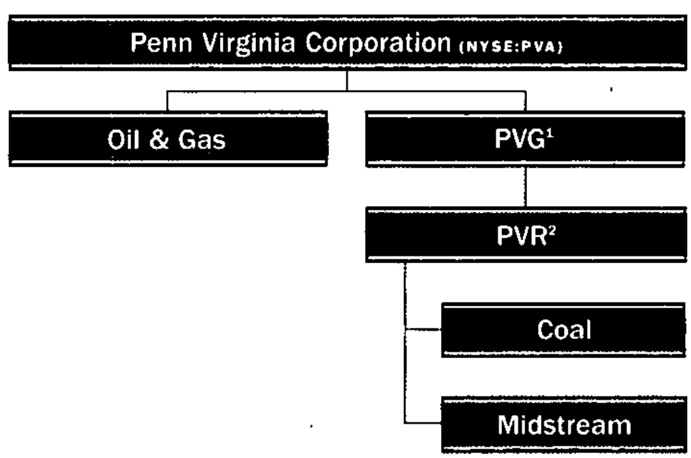
A. James Dearlove
President and Chief Executive Officer

► The Penn Virginia Group

Penn Virginia's exposure to natural gas, coal and natural gas midstream is unique among energy companies and provides multiple opportunities to achieve superior shareholder returns. In 2001, we established Penn Virginia Resource Partners, L.P. (PVR), a tax-efficient structure to house our coal and land assets. In 2005, we added natural gas midstream assets to the partnership. As PVR has grown and increased unitholder distributions, the value of its general partner interests also increased. To better establish the overall value of our holdings in PVR's limited and general partnership interests, we created a publicly traded partnership, Penn Virginia GP Holdings, L.P. (PVG), to hold these interests.

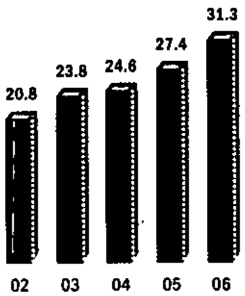
With the value of our position in PVR clearly defined by PVG, the market should find it easier to value each of our business segments. With a portfolio of high quality assets including E&P, coal reserves and midstream operations, as well as multiple currencies in various tax efficient structures, the Penn Virginia "family" is well positioned for future growth.

► Penn Virginia Organization



(1) Penn Virginia GP Holdings, L.P. (NYSE:PVG)
(2) Penn Virginia Resource Partners, L.P. (NYSE:PVR)

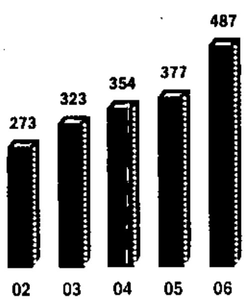
OIL & GAS PRODUCTION *(Bcfe)*



2006
Production

	(Bcfe)	% Total
Appalachia/ Conventional	7.0	22%
Appalachia/CBM	5.8	19%
Mississippi/ Selma Chalk	6.4	20%
East Texas/ Cotton Valley	4.6	15%
Mid-Continent	1.2	4%
Gulf Coast	6.3	20%
Totals	**31.3**	**100%**

PROVED OIL & GAS RESERVES *(Bcfe)*



12/31/2006
Proved Oil & Gas Reserves

	(Bcfe)	% Total
Appalachia/ Conventional	120.8	25%
Appalachia/CBM	35.2	7%
Mississippi/ Selma Chalk	120.6	25%
East Texas/ Cotton Valley	109.3	22%
Mid-Continent	51.5	11%
Gulf Coast	49.3	10%
Totals	**486.7**	**100%**

2006 was a record year for our oil and gas exploration and production (E&P) segment in terms of production and reserve growth. We intend to build on this success in 2007 as evidenced by our announced capital expenditures budget of $334 million, excluding acquisitions.

During 2006, we added a new core operating area in the Mid-Continent region (see page 8) and we enjoyed strong growth from our east Texas Cotton Valley play (see inset on next page) and our Mississippi Selma Chalk play. Our horizontal CBM program continued to be an important part of our portfolio despite various operational challenges, which we expect to resolve in 2007.

Our strategy is to continue to focus on relatively low risk, unconventional natural gas oriented resource plays in our core areas, complemented by our predominantly Gulf Coast exploration program, which exposes us to meaningful increases in our production and proved reserves. The relatively low risk plays include the Cotton Valley program in east Texas, the Selma Chalk in Mississippi and horizontal coalbed methane (HCBM) in Appalachia and in the Mid-Continent. We are also assessing the potential of various shale plays including the Fayetteville Shale in Arkansas and Devonian Shale in Appalachia. Augmenting our lower risk asset base, we continue to exploit our Gulf Coast exploration expertise by participating in drilling select onshore prospects in south Louisiana and south Texas, many of which are internally generated.

Our increased E&P operating income and cash flows in 2006 were the direct result of record drilling activity, which also led to impressive reserve and production growth:

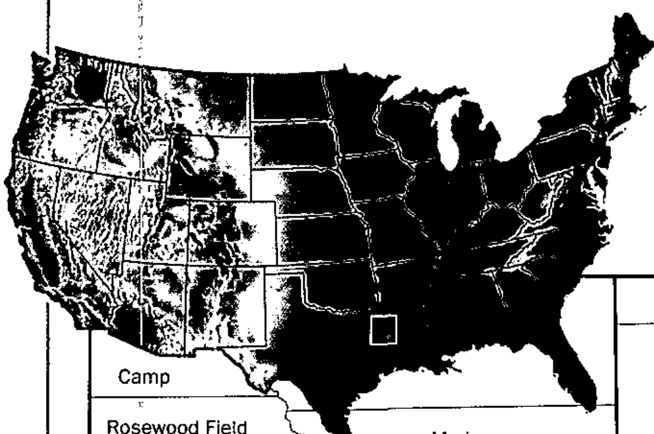
- We drilled 210 wells during 2006, including 190 development wells and 20 exploratory wells. All but three of the development wells were successful and 13 of the exploratory wells were successful, for a 95 percent overall success rate.
- Oil and gas production in 2006 was 31.3 billion cubic feet of natural gas equivalent (Bcfe), a new Company record which eclipsed the 27.4 Bcfe in 2005 by 14 percent. We expect production to grow significantly in 2007.
- Our estimated proved reserves at the end of 2006 were a Company record 487 Bcfe, up 29 percent from 377 Bcfe at the end of 2005, including new reserves from the Mid-Continent acquisition. Natural gas comprised approximately 94 percent of year-end 2006 proved reserves, and 71 percent of reserves were proved developed. Net of revisions, we added approximately 141 Bcfe of proved reserves primarily from extensions, discoveries and acquisitions, replacing approximately 454 percent of 2006 production.

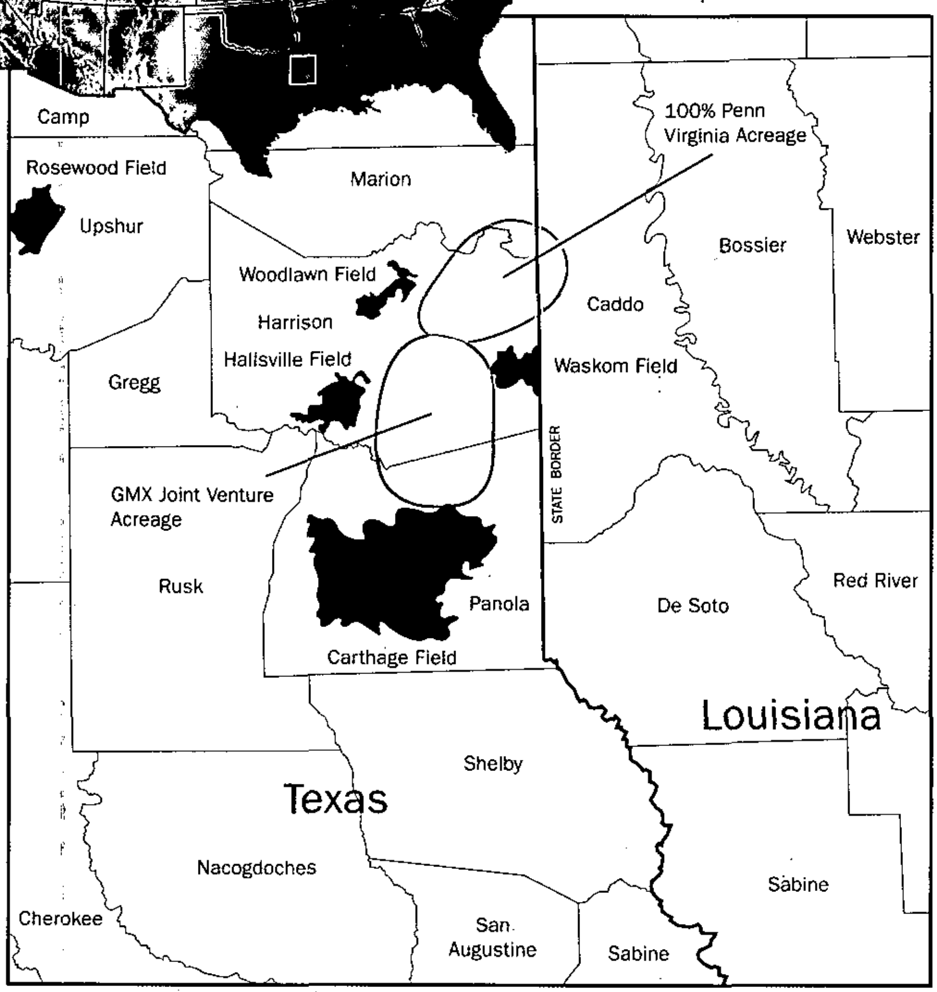
Remaining consistent with our strategy to exploit our expertise in relatively low risk, unconventional plays, approximately 84 percent of our Company-record $334 million oil and gas capital expenditures budget for 2007 is devoted to drilling 335 wells in our core development areas. We also plan to spread our exploration spending among projects in the Gulf Coast and in each of our other core areas, targeting various promising ideas involving shales and tight sands. We do not budget acquisitions, but continuously review opportunities which would complement our strategy. As part of our strategy, we employ commodity hedges to protect our budgeted cash flow.

▸ The Cotton Valley Play of East Texas

In early 2004, the Company entered into a joint venture with GMX Resources, Inc. (NASDAQ: GMXR) to drill development wells in the North Carthage Field in east Texas.

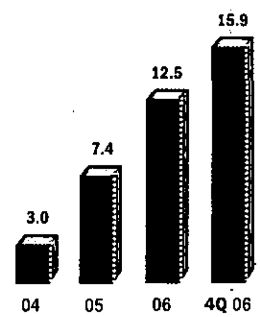
The transaction provided the Company with drilling rights on 13,500 net acres on which we had expected to drill 80 to 100 wells. By the end of 2006, our acreage position had expanded to 38,000 net exploratory and development acres on which we had an estimated 600 40-acre drilling locations. Through December 31, 2006, 103 wells have been drilled and we plan to drill 98 wells during 2007. Recently, the Texas Railroad Commission approved 20-acre well spacing on the majority of our acreage. Strong growth in production, the large number of potential drilling locations and the high success rates all combine to fuel our growing optimism about the Cotton Valley.



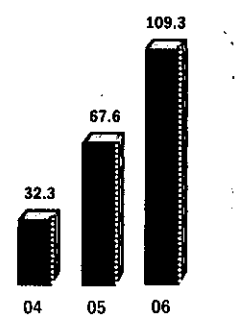


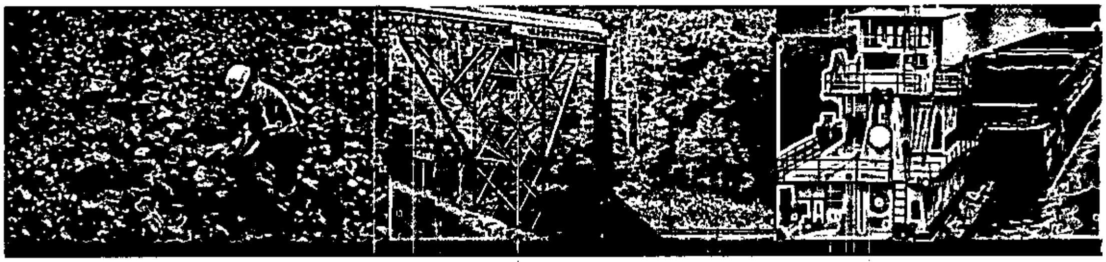
Cotton Valley Operating Data

OIL & GAS PRODUCTION *(MMcfe/d)*

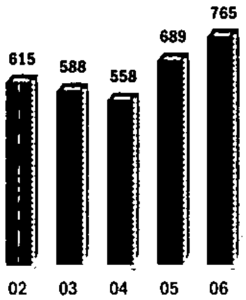


PROVED OIL & GAS RESERVES *(Bcfe)*





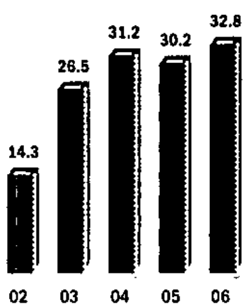
PROVEN AND PROVABLE COAL RESERVES
(Millions of tons)



2006
Production

	(MM tons)	% Total
Central Appalachia	20.2	62%
Northern Appalachia	5.0	15%
Illinois Basin	2.5	8%
San Juan Basin	5.1	15%
Totals	32.8	100%

COAL PRODUCED BY PVR LESSEES
(Millions of tons)



12/31/2006
Coal Reserves

	(MM tons)	% Total
Central Appalachia	558.9	73%
Northern Appalachia	36.0	5%
Illinois Basin	112.6	15%
San Juan Basin	57.9	7%
Totals	765.4	100%

As of December 31, 2006, PVR owned or controlled approximately 765 million tons of proven and probable coal reserves, an increase of 11 percent from the prior year level. PVR's reserves are located in central Appalachia, northern Appalachia, the San Juan Basin and the Illinois Basin. Coal production by PVR's lessees increased nine percent to 32.8 million tons in 2006, from 30.2 million tons in 2005, primarily due to acquisitions, with 1.2 million tons of the increase attributable to central Appalachia and 1.1 million tons of the increase attributable to the Illinois Basin.

PVR completed three coal reserve acquisitions during 2006, adding approximately 96 million tons of coal for a total acquisition cost of approximately $76 million. Approximately 74 million of those tons consist of high quality coal located in central Appalachia.

Approximately 22 million tons of the coal PVR acquired is in the western Kentucky portion of the Illinois Basin. The Illinois Basin acquisition complements the approximate 94 million tons of western Kentucky coal PVR purchased in 2005. PVR believes that production from the Illinois Basin will accelerate as environmental regulations become more stringent and as technological advances make it environmentally acceptable to use the basin's high sulfur coal. As a result, PVR plans to increase its position in the Illinois Basin over time.

During 2006, worldwide and domestic demand for coal and other hydrocarbons continued to be strong, although coal prices began to decline from their highs during the fourth quarter. PVR believes the decline in coal prices will primarily impact operators who have a high cost structure and also operators who do not have long-term contracts in place. In PVR's case, most of its lessees are low-cost operators who have long-term contracts with most of their customers.

In 2006, approximately 70 percent of the coal produced from PVR's properties was subject to leases which required its lessees to pay royalties based on a percentage of the price they received for selling the coal. Most of that coal is sold by PVR's lessees under long-term contracts. Prices under those contracts increased significantly for contracts renewed during 2006. The royalties PVR received on the other 30 percent of coal produced from PVR's properties were based on fixed rates per ton, which escalate annually. PVR's average royalty rates in 2006 increased nine percent to $2.99 per ton from $2.74 per ton in 2005.

PVR will continue its efforts to build a coal services and infrastructure business. Currently, PVR owns and leases to various operators who mine on PVR's properties, facilities that process and load coal onto railroad cars. PVR also plans to add to its coal handling business which serves the end users of coal, such as power plants.

Through PVR Midstream, PVR owns and operates natural gas midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing plants, which have 160 million cubic feet per day (or MMcfd) of total capacity.

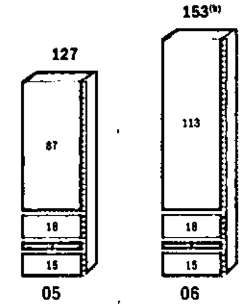
PVR Midstream derives revenues primarily from gas processing contracts with natural gas producers and from fees charged for gathering natural gas volumes and providing other related services. PVR Midstream also operates a natural gas marketing business, which aggregates third-party volumes and sells those volumes into intrastate pipeline systems and at market hubs accessed by various interstate pipelines.

PVR acquired its natural gas midstream assets through the acquisition of Cantera Gas Resources, LLC in March 2005. The acquisition established a platform for future growth and diversified PVR's cash flows into another long-lived asset base.

During 2006, inlet volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 56.0 billion cubic feet (or Bcf), or approximately 153 MMcfd, a 20 percent increase over the 127 MMcfd average in 2005. Gross midstream processing margin increased to $68.1 million, or $1.22 per thousand cubic feet (Mcf), for 2006 from the $44.7 million, or $1.15 per Mcf, for the ten months in 2005 that PVR owned the midstream operations. Midstream operating income in 2006 was $29.4 million, or 29 percent of PVR's total.

Much of PVR's profitability depends on the relationship between the price it receives for the natural gas liquids (NGLs) it extracts and sells at its processing plants and the price of natural gas it buys as feedstock. The difference between these two prices, the so-called "frac spread," can be volatile and difficult to predict. Therefore, PVR employs various hedges to protect its margins and help insure a steady, predictable cash flow stream.

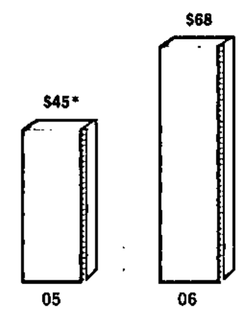
2006 INLET VOLUMES[a]
MMcf per day



2005	Beaver System	69%
	Crescent System	14%
	Hamlin System	5%
	Arkoma System[c]	12%
2006	Beaver System	74%
	Crescent System	12%
	Hamlin System	4%
	Arkoma System[c]	10%

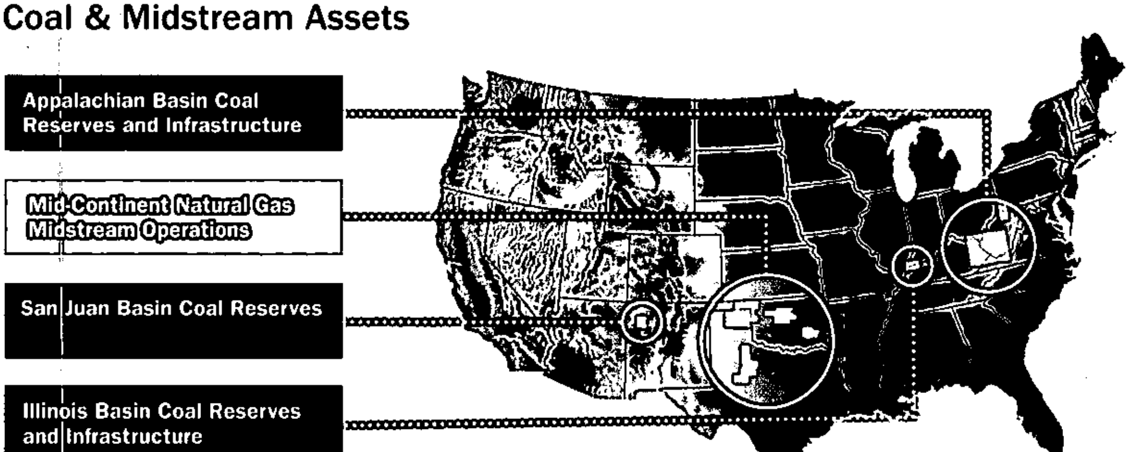
[a] 10 month data for 2005
[b] 163MMcfd, assuming full year of a mid-year acquisition
[c] Gathering volumes only

2006 PROCESSING MARGINS
Dollars in Millions



** 10 month data*

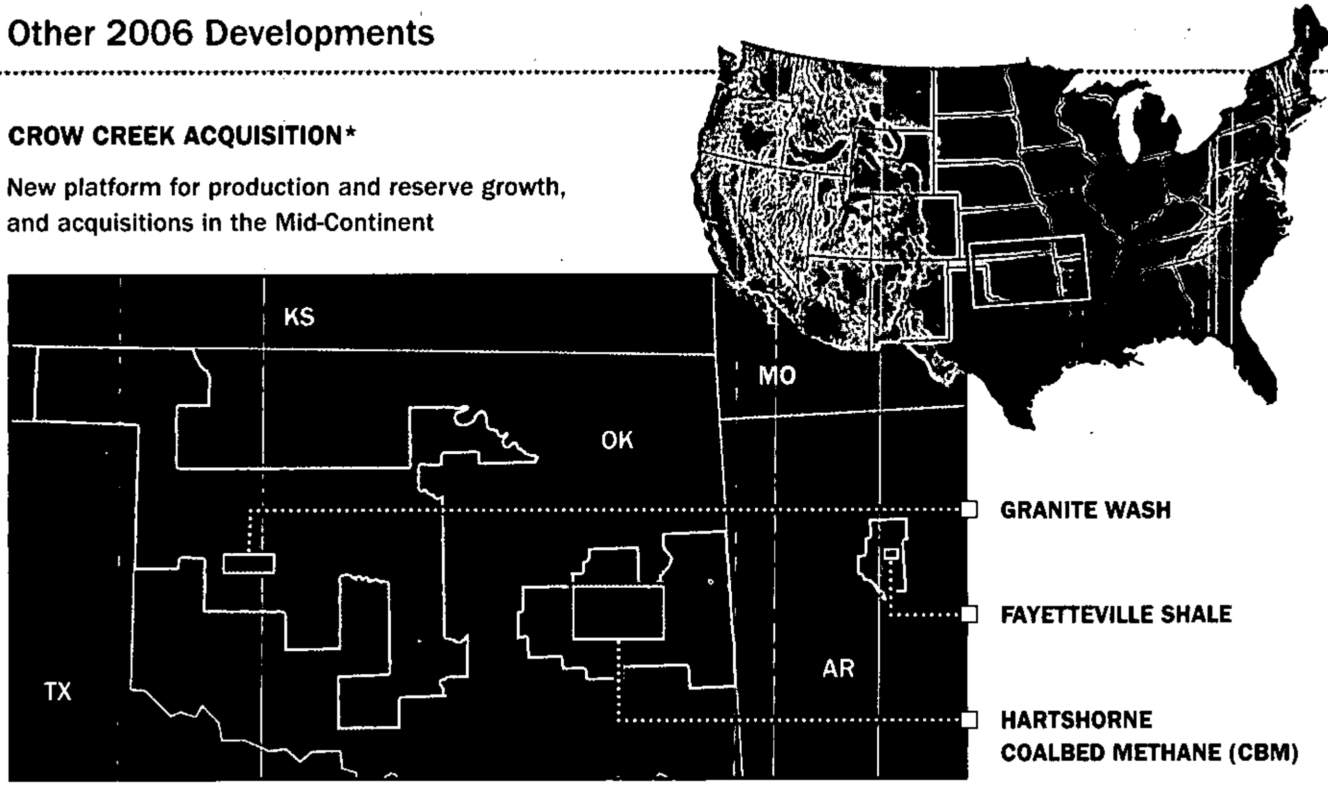
► Coal & Midstream Assets



► Other 2006 Developments

CROW CREEK ACQUISITION*

New platform for production and reserve growth, and acquisitions in the Mid-Continent

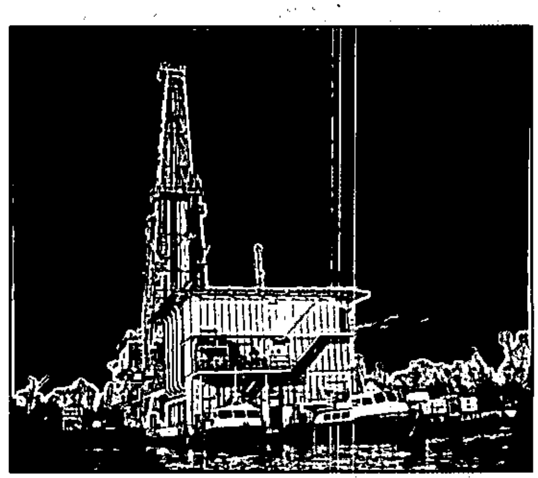


- $72 million cash acquisition price, funded by existing bank facility
- 30,000 acres; 23 percent held by production
- 43 Bcfe of proved reserves
- Additional probable and possible reserves and drilling locations
- Cash acquisition price of $1.67 per Mcfe of proved reserves, 61 percent proved developed and 85 percent natural gas
- Hartshorne CBM in the Arkoma Basin – 33 percent of proved reserves
- Granite Wash in the Anadarko Basin – 20 percent of proved reserves
- Other conventional plays – 47 percent of proved reserves
- Daily production of 6.2 MMcfe
- 482 proved developed producing wells (110 operated wells) with a working interest in the wells of 69 percent
- 180 Hartshorne CBM and Granite Wash drilling locations added to inventory
- Establishes a new core area and added a new regional office in Tulsa
- Mid-Continent region is a large market for acquisitions and development and exploratory plays, including the Fayetteville Shale in Arkansas

* data as of the time of the acquisition, unless otherwise noted

► Bayou Postillion — South Louisiana Exploratory Success

In October 2006, the Cotton Land Corp. #1 well (0.4 net to PVA) was successfully brought on line at our Bayou Postillion Prospect in Iberia Parish, Louisiana. The initial gross sales flow rate was in excess of 10 million cubic feet of natural gas equivalent (MMcfe) per day, which subsequently increased to approximately 15 MMcfe per day. The Marie Snyder #1 well (0.1 net) and Cotton Land Corp. #3 well (0.5 net) were successfully completed in late 2006 and early 2007 at Bayou Postillion. To date, there have been six successful wells drilled in Bayou Postillion and additional drilling is planned in 2007. Bayou Postillion is an example of the benefit we receive from our higher risk, higher return exploration program in the Gulf Coast that comprises a small part of our capital budget but can deliver disproportionate contributions to production and reserves.



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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, 2006

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 of 1933. 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. 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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 $1,289,572,927 as of June 30, 2006 (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 all executive officers of the registrant, but excluding any institutional shareholders. This determination is not necessarily a conclusive determination for other purposes.

As of February 28, 2007, 18,791,869 shares of common stock of the registrant were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

	Part Into Which Incorporated
(1) Proxy Statement for Annual Meeting of Shareholders on May 8, 2007	Part III

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

Table of Contents

PART I

Item 1 *Business*

General

Penn Virginia Corporation is a Virginia corporation founded in 1882 whose common stock is traded on the New York Stock Exchange under the symbol "PVA." We are engaged in the exploration, development and production of crude oil and natural gas primarily in the Appalachian, Mississippi, Mid-Continent and Gulf Coast onshore areas of the United States. We also collect royalties on various oil and gas properties in which we own a mineral fee interest. Unless the context requires otherwise, references to the "Company," "we," "us" or "our" in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

We are also indirectly involved in the businesses engaged in by Penn Virginia Resource Partners, L.P., or PVR, a Delaware limited partnership whose common units are traded on the New York Stock Exchange under the symbol "PVR." We own PVG GP, LLC, the sole general partner of Penn Virginia GP Holdings, L.P., or PVG, a Delaware limited partnership whose common units are traded on the New York Stock Exchange under the symbol "PVG." We also own an approximately 82% limited partner interest in PVG. As of December 31, 2006, PVG owned approximately 44% of PVR, consisting of a 2% general partner interest and an approximately 42% limited partner interest in PVR. We directly own an additional 0.6% interest in PVR. As part of its ownership of PVR's general partner, PVG also own the rights, referred to as "incentive distribution rights," to receive an increasing percentage of PVR's quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. See Item 1, "Business—Partnership Distributions," for more information on incentive distribution rights.

PVR conducts operations in two business segments: coal and natural gas midstream. PVR does not operate any coal mines, but rather leases its coal reserves to various mining operators in exchange for royalty payments. Additionally, PVR provides fee-based coal preparation and loading facilities to some of its lessees and to other third party industrial end-users. With the acquisition of a natural gas midstream business in March 2005, PVR entered the midstream gas gathering and processing business with primary locations in the Mid-Continent area of Oklahoma and the Texas panhandle.

Segments

We operate in three primary business segments. We are in the crude oil and natural gas exploration and production business and, through our direct and indirect ownership interests in PVR, we are in the coal and natural gas midstream businesses. In 2006, approximately 50% of our operating income was attributable to our oil and gas segment, 43% was attributable to our coal segment and 17% was attributable to our natural gas midstream segment, less a 10% operating loss related to corporate and other functions. See Note 20 in the Notes to Consolidated Financial Statements for financial information concerning our business segments.

Oil and Gas Segment Overview

In our oil and gas segment, we explore for, develop, produce and sell crude oil, condensate and natural gas primarily in the Appalachian, Mississippi, Mid-Continent and Gulf Coast onshore regions of the United States. At December 31, 2006, we had proved oil and natural gas reserves of approximately 5 million barrels of oil and condensate and 457 billion cubic feet (or Bcf) of natural gas, or 487 billion cubic feet equivalent (or Bcfe). Oil and natural gas production from our properties increased to 31.3 Bcfe in 2006, an increase of 14% from 27.4 Bcfe produced in 2005.

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 is also highly dependent on the results of our exploratory and development drilling programs.

In addition to our conventional development program, we have continued to expand our development of unconventional plays such as coal bed methane (or CBM) gas reserves in Appalachia and Mid-Continent and the Cotton Valley play in east Texas. We are committed to expanding our oil and gas reserves and production primarily by developing our existing inventory of drilling locations and by using our ability to internally generate exploratory prospects and development drilling programs.

PVR Coal Segment Overview

PVR's coal segment includes management and leasing of coal properties and subsequent collection of royalties. Substantially all of PVR's leases require the lessee to pay minimum rental payments to PVR in monthly or annual installments. PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from its properties. PVR also earns revenues from providing fee-based coal preparation and transportation services to its lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through its joint venture with Massey Energy Company, or Massey. In addition, PVR earns revenues from oil and gas royalty interests it owns, from coal transportation, or wheelage, rights and from the sale of standing timber on its properties.

As of December 31, 2006, PVR owned or controlled approximately 765 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2006, approximately 87% of PVR's proven and probable coal reserves was "steam" coal used primarily by electric generation utilities, and the remaining 13% was metallurgical coal used primarily by steel manufacturers. PVR enters into long-term leases with experienced, third-party mine operators providing them the right to mine its coal reserves in exchange for royalty payments. PVR does not operate any mines. In 2006, PVR's lessees produced 32.8 million tons of coal from its properties and paid to PVR coal royalty revenues of $98.2 million, for an average gross coal royalty per ton of $2.99. Approximately 84% of PVR's coal royalty revenues in 2006 and 83% of PVR's coal royalty revenues in 2005 were derived from coal mined on its 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 royalty revenues for the respective periods was derived from coal mined on its properties under leases containing fixed royalty rates that escalate annually.

PVR's management continues to focus on acquisitions that increase and diversify its sources of cash flow. During 2006, PVR increased its coal reserves by 96 million tons, or 14%, from its coal reserves as of December 31, 2005, by completing three coal reserve acquisitions with an aggregate purchase price of approximately $76 million. For a more detailed discussion of PVR's acquisitions, see Item 7, "Managements' Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments."

PVR Natural Gas Midstream Segment Overview

PVR owns and operates midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and the panhandle of Texas, which have 160 million cubic feet per day (or MMcfd) of total capacity. PVR's 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 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 acquired its natural gas midstream assets from Cantera Gas Resources, LLC, or Cantera, in March 2005. PVR's management believes that this acquisition established a platform for future growth in the natural gas midstream sector and diversified its cash flows into another long-lived asset base. Since acquiring these assets, PVR has expanded its natural gas midstream business by adding 181 miles of new gathering lines.

For the year ended December 31, 2006, inlet volumes at PVR's gas processing plants and gathering systems, including gathering-only volumes, were 56.0 Bcf, or approximately 153 MMcfd. Two of PVR's natural gas midstream customers, ConocoPhillips Company and BP Canada Energy Marketing Corp., accounted for 32% and 17% of PVR's natural gas midstream revenues in 2006.

Corporate and Other

Corporate and other primarily represents corporate functions.

Business Strategy

We intend to pursue the following business strategies:

- *Focus on relatively low risk, unconventional natural gas-oriented resource plays.* In addition to our established core areas, such as the horizontal CBM play in Appalachia, the Cotton Valley play in east Texas and north Louisiana and the Selma Chalk in Mississippi, we are assessing the potential to establish new sustainable growth in organic shale and other unconventional plays in new areas, such as the Williston and Illinois Basins. We work with established industry partners in several of these core and potential new areas.
- *Generate and drill exploratory prospects.* We intend to concentrate on exploratory prospects in south Texas and south Louisiana, which could result in an increase in our proved reserves and production. As compared to our lower risk unconventional plays, these prospects tend to have relatively higher risk profiles and higher returns when successful, and we work with industry partners to better manage costs and risks.
- *Continue to grow coal reserve holdings through acquisitions and investments in PVR's existing market areas, as well as strategically entering new markets.* During 2006, PVR increased its coal reserves by 96 million tons, or 14%, from its coal reserves as of December 31, 2005, by completing three coal reserve acquisitions with an aggregate purchase price of approximately $76 million. While PVR continues to build upon its core holdings in Appalachia, it also continues to monitor coal opportunities in other areas. For example, in 2005 and 2006, PVR made investments in Illinois Basin coal reserves because PVR views the Illinois Basin as a growth area, both because of its proximity to power plants and because PVR expects future environmental regulations will require scrubbing of not only higher sulfur Illinois Basin coal, but most coals, including lower sulfur coals from other basins. PVR expects to continue to diversify its coal reserve holdings into this and other domestic basins in the future.
- *Expand PVR's coal services and infrastructure business on its properties.* Coal infrastructure projects typically involve long-lived, fee-based assets that generally produce steady and predictable cash flows and are therefore, attractive to publicly traded limited partnerships. PVR owns a number of such infrastructure facilities and intends to continue to look for growth opportunities in this area of operations. For example, PVR completed construction of a new preparation and loading facility in September 2006 on property it acquired in 2005. Operations at the facility commenced in the fourth quarter of 2006. PVR's joint venture with Massey is expected to provide other development opportunities for coal-related infrastructure projects.
- *Expand PVR's midstream operations through acquisitions of new gathering and processing related assets and by adding new production to existing systems.* PVR continually seeks new supplies of natural gas both to offset the natural declines in production from the wells currently connected to its systems and to increase throughput volume. New natural gas supplies are obtained for all of PVR's systems by contracting for production from new wells, connecting new wells drilled on dedicated

acreage and by contracting for natural gas that has been released from competitors' systems. In 2006, PVR added approximately 181 miles of new gathering lines, allowing it to connect 158 new wells to its systems.

- *Expand PVR's midstream operations by utilizing the advantages of PVR's relationship with us.* During 2006, PVR began marketing our natural gas production in Louisiana, Oklahoma and Texas, replacing a third party marketing company and allowing us to realize higher prices for our oil and natural gas sold in that region. We will continue to look for ways to take advantage of our natural relationship with PVR in mutually beneficial ways.
- *Maintain financial discipline and flexibility.* We, PVG and PVR operate with separate, independent capital structures. We intend to continue to be fiscally conservative in all three entities and to manage our capital structure for the long term, which means that we will continue to be cautious regarding debt levels and dividend or distribution increases.

Contracts

Oil and Gas Segment

Transportation. The majority of our natural gas production is transported to market on three major pipeline or transmission systems. NiSource Inc., Crosstex Energy Services L.P. and Gulf South Pipeline Company, LP transported 32%, 20% and 19% of our 2006 natural gas production. The remainder of our natural gas production was transported by several pipeline companies in Louisiana, Texas and West Virginia. In almost all cases, our natural gas is sold at interconnects with transmission pipelines.

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, 2006, three customers of our oil and gas segment, Crosstex Gulfcoast Marketing, Dominion Field Services and Amerada Hess Corporation, accounted for approximately 24%, 22% and 11% of our natural gas and oil and condensate revenues of $234.2 million.

PVR Coal Segment

PVR earns most of its coal royalty 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 royalty revenues are earned under two long-term leases with affiliates of Peabody Energy Corporation (NYSE: BTU), or Peabody, that require the lessees to make royalty payments to PVR based on fixed royalty rates which escalate annually. A typical lease either expires upon exhaustion of the leased reserves, which is the case with the two Peabody leases, 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 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.

In addition to the terms described above, 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 it 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 our 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.

PVR Natural Gas Midstream Segment

PVR's natural gas midstream segment is engaged in providing gas processing, gathering and other related natural gas services. PVR's 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, 2006, 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 natural gas liquids (or NGLs): (i) percentage-of-proceeds and (ii) keep-whole arrangements. In 2006, approximately 50% of PVR's natural gas volumes were processed under gas purchase/keep-whole contracts, 25% were processed under percentage of proceeds contracts, and 25% were 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. There is also a processing fee floor included in many of the gas purchase/keep-whole contracts that ensures a minimum processing margin should the actual margins fall below the floor.

Gas purchase/keep-whole arrangements. Under these 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 British thermal unit (or 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 ensures that PVR receives a minimum amount of processing revenue. 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 revenue PVR earns from these arrangements is directly dependent on the volume of natural gas that flows through its systems and is 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 its 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.

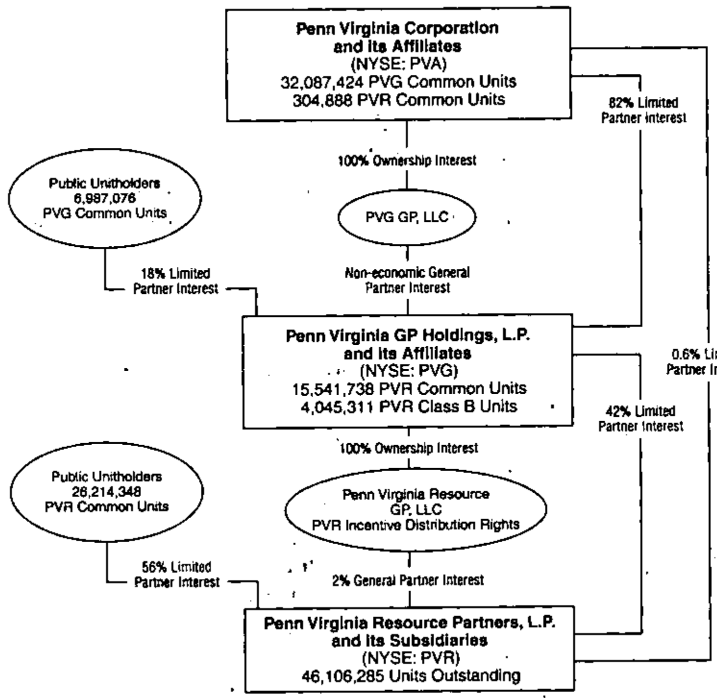
PVR is also engaged in natural gas marketing by aggregating third-party volumes and selling those volumes into interstate and intrastate pipeline systems such as Enogex and ONEOK and at market hubs accessed by various interstate pipelines. The largest third-party customer is Chesapeake Energy Corp. with volumes contracted through 2007. Revenue from this business does not generate qualifying income for a master limited partnership, but PVR does not expect it to have an impact on its tax status, as it does not represent a significant percentage of its operating income. For the year ended December 31, 2006, this business generated $2.2 million in net revenue.

Commodity Derivative Contracts

Our oil and gas and natural gas midstream segments utilize costless collars, three-way collars and swap derivative contracts to hedge against the variability in cash flows associated with forecasted oil and gas revenues and natural gas midstream revenues and cost of midstream gas purchased. While the use of derivative instruments limits the risk of adverse price movements, their use also may 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 us if the settlement price for any settlement period is below the floor price for such contract. We are required to make 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. A three-way collar contract consists of a collar contract as described above plus a put option contract sold by us with a price below the floor price of the collar. This additional put 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. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option. With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. See Note 10 in the Notes to Consolidated Financial Statements for a description of our derivative program.

Corporate Structure

Because we control the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVG include those of PVR. However, PVG and PVR function with a capital structure that is 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. The following diagram depicts our ownership of PVG and PVR as of December 31, 2006 (after giving effect to the exercise of the underwriters' option to purchase additional PVG common units granted in connection with PVG's initial public offering, or the PVG IPO):



Partnership Distributions

PVG Cash Distributions

PVG paid a cash distribution of $0.07 per common unit on February 14, 2007, which represented a $0.96 per unit distribution on an annualized basis that was prorated for the period beginning on December 5, 2006, the initial trading date of PVG's common units on the New York Stock Exchange, and ending on December 31, 2006. We received total distributions from PVG of $2.2 million in February 2007. For the remainder of 2007, PVG expects to make quarterly distributions of $0.24 ($0.96 on an annualized basis) or more per common unit.

PVR Cash Distributions

PVR paid cash distributions of $1.475 per common and subordinated unit during the year ended December 31, 2006. In the first quarter of 2007, PVR paid a quarterly distribution of $0.40 ($1.60 on an annualized basis) per unit with respect to the fourth quarter of 2006. For the remainder of 2007, PVR expects to pay quarterly distributions of $0.40 ($1.60 on an annualized basis) or more per common and Class B unit.

Prior to the PVG IPO in December 2006, we indirectly owned common units representing an approximately 37% limited partner interest in PVR, as well as the sole 2% general partner interest and all of the incentive distribution rights in PVR. We received total distributions from PVR of $28.3 million and $21.2 million in 2006 and 2005, as shown in the following table (in thousands):

	Year Ended December 31,	
	2006	2005
Limited partner units	$22,799	$19,281
General partner interest (2%)	1,254	1,021
Incentive distribution rights	4,273	910
Total	$28,326	$21,212

In conjunction with the PVG IPO, we contributed our limited partner interest and general partner interest, including our incentive distribution rights, in PVR to PVG in exchange for a limited partner interest and the general partner interest in PVG. PVG also purchased additional common units and Class B units of PVR with the proceeds of the PVG IPO. Consequently, PVG is currently entitled to receive certain cash distributions payable with respect to the common and Class B units of PVR, the 2% general partner interest in PVR and the incentive distribution rights in PVR.

PVR Incentive Distribution Rights

A wholly owned subsidiary of PVG is the general partner of PVR and, as such, holds certain incentive distribution rights which represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after PVR has paid minimum quarterly distributions and certain target distribution levels have been achieved. The minimum quarterly distribution is $0.25 per unit ($1.00 per unit on an annualized basis). PVR's general partner currently holds 100% of the incentive distribution rights, 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 the general partner with or into such entity or the transfer of all or substantially all of the 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 incentive distribution rights will require the affirmative vote of holders of a majority of PVR's outstanding common units and subordinated units, voting as separate classes. On or after September 30, 2011, the incentive distribution rights will be freely transferable. The incentive distributions rights are payable as follows:

If for any quarter:

- PVR has distributed available cash from operating surplus to its common, subordinated and Class B unitholders and 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 our general partner subsidiary in the following manner:

- First, 98% to all unitholders, and 2% to the 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 the 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 the 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 the general partner.

Subordinated Units

Until November 14, 2006, PVR had a separate class of subordinated units representing of limited partner interests in PVR, and the rights of holders of subordinated units to participate in distributions to limited partners were subordinated to the rights of the holders of PVR's common units. On November 14, 2006, all of PVR's subordinated units converted into common units on a one-for-one basis and no subordinated units remain outstanding.

Class B Units

PVR currently has a separate class of units representing limited partner interests in PVR called Class B units. Each Class B unit is currently entitled to receive 100% of the quarterly cash distribution paid in respect of each common unit except that the Class B units are subordinated to the common units with respect to the payment of the minimum quarterly distribution and any arrearages with respect to the payment of the minimum quarterly distribution. PVR is required to submit to a vote of its unitholders, as promptly as practicable, a proposal to change the terms of the Class B units in order to provide that the Class B units will convert into common units, on a one-for-one basis, immediately upon the approval by PVR's unitholders. Holders of the Class B units will not be entitled to vote upon the proposal to change the terms of the Class B units, but otherwise will vote with the common units as a single class on each matter with respect to which the common units are entitled to vote. If PVR's unitholders do not approve the proposal to change the terms of the Class B units before December 8, 2007, then each Class B unit will be entitled to receive 115% of the quarterly amount PVR distributes in respect of each common unit on a subordinated basis to the payment of the minimum quarterly distribution on the common units.

Upon the dissolution and liquidation of PVR, each Class B unit is currently entitled to receive 100% of the amount distributed on each common unit, but only after each common unit has received an amount equal to its capital account, plus the minimum quarterly distribution for the quarter in which the liquidation occurs, plus any arrearages in the minimum quarterly distribution with respect to prior quarters. If, however, PVR's unitholders do not approve the proposal to change the terms of the Class B units to make them convertible into common units, then each Class B unit will be entitled upon liquidation to receive 115% of the amount distributed in respect of each common unit, but only after each common unit has received an amount equal to its capital account, plus the minimum quarterly distribution for the quarter in which the liquidation occurs, plus any arrearages in the minimum quarterly distribution with respect to prior quarters on a subordinated basis to liquidating distributions on the common units.

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 major 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 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 requirements.

PVR Midstream Segment

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.

PVR experiences competition in all of its 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.

Government Regulation and Environmental Matters

The operations of our oil and segment and PVR's coal segment and natural gas midstream segment 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 natural gas liquids 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.

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 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). 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. 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. 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 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 federal Clean Air Act and corresponding state and local laws and regulations affect all aspects of PVR's business. The Clean Air Act 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 Clean Air Act 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 U.S. Environmental Protection Agency (or the EPA) laws and regulations will make it more costly to 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 royalty revenues.

The EPA's Acid Rain Program, provided in Title IV of the Clean Air Act, 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 will permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C beginning in 2009 and 2010, respectively. CAIR requires these 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.

In March 2005, the EPA finalized the Clean Air Mercury Rule (or CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. While currently the subject of extensive controversy and litigation, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

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. For example, in December 2004, the EPA designated specific areas in the United States as in "non-attainment" with the new national ambient air quality standard for fine particulate matter. In November 2005, the EPA published proposed rules addressing how states would implement plans to bring applicable non-attainment regions into compliance with the new air quality standard. Under the EPA's proposed rulemaking, states would have 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.

In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. As part of the new rules, affected states must 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 Clean Air Act. The

EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. 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 royalty 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. Since the Kyoto Protocol became effective, there has been increasing international pressure on the United States to adopt mandatory restrictions on carbon dioxide emissions. The United States Congress has considered bills in the past that would regulate domestic carbon dioxide emissions, but such bills have not yet received sufficient Congressional support for passage into law. 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 electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program 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. Recently, in February 2007, Massachusetts and Rhode Island agreed to join this group. Maryland is required to join the group by June 2007, but implementing regulations have not been finalized as of yet.

It is possible that future federal and state initiatives to control carbon dioxide 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 affect on PVR's coal royalty revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 (or SMCRA) and similar state statutes impose 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 require mine operators to post performance bonds to ensure compliance with any reclamation obligations. Regulatory authorities may attempt to assign the liabilities of PVR's coal lessees to it if any of those lessees are not financially capable of fulfilling those obligations. 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.

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 PVR's 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 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.

Water Discharges. PVR's coal lessees' operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States or state waters. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

PVR's lessees' mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into jurisdictional waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was vacated by the Fourth Circuit Court of Appeals in November 2005, a similar lawsuit has been filed in federal district court in Kentucky that seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. 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 Clean Water Act 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 royalty revenues. Moreover, such individual permits are also subject to challenge. Alex Energy, Inc., a PVR lessee operating the Republic No. 2 Mine in Kanawha County, West Virginia, is currently a defendant in *Ohio Valley Environmental Coalition vs. U.S. Army Corps of Engineers*, a lawsuit in the Southern District of West Virginia in which environmental groups challenged the issuance of individual valley fill permits to multiple coal operators in the state. On June 13, 2006, the Corps of Engineers suspended the valley fill permits at issue in the case, including the permit under which PVR's lessee operates. The court has since stayed all proceedings pending further action by the Corps on these permits. Although portions of the Republic No. 2 Mine continue to operate under separate authorizations, delays in securing additional permit authorization for the areas affected by the aforementioned permit withdrawal could have an adverse effect on PVR's coal royalty revenues.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired waterbodies 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 its lessees to modify existing operations, which could have an adverse effect on PVR's coal business.

The Federal 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.

Mine Health and Safety Laws. The operations of PVR's 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 and reduced productivity. 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 new mining safety legislation that mandates similar 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. Earlier, the federal Mine Safety Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the *Federal Register* on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect PVR's lessees' coal production and could therefore have an adverse affect on PVR's coal royalty 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 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.

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 Segment—Water Discharges."

OSHA. PVR's lessees and its 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 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. PVR cannot predict whether its 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, as amended (or the NGPSA), which requires certain pipelines to comply with safety standards in constructing and operating the pipelines, and subjects pipelines to regular inspections. In response to recent pipeline accidents, Congress and the U.S. Department of Transportation have recently 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 midstream operations are subject to the Clean Air Act and comparable state laws and regulations. See "—PVR Coal 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 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 PVR 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 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 Segment—Hazardous Materials and Waste." Although petroleum, including natural gas and NGLs are generally excluded from CERCLA's definition of "hazardous substance," PVR's midstream operations do generate wastes in the course of ordinary operations that may fall within the definition of a "hazardous substance."

PVR's midstream operations generate wastes, including some hazardous wastes, that are subject to the Resource Conservation and Recovery Act (or 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 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 we believe 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 midstream operations are subject to the Clean Water Act. See "—PVR Coal Segment—Water Discharges." 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 midstream's operations are subject to OSHA. See "—Oil and Gas Segment—OSHA.".

Employees and Labor Relations

We and our subsidiaries had a total of 282 employees at December 31, 2006, including 122 employees who directly provide services for PVR. We consider our current employee relations to be favorable.

Available Information

Our internet address is www.pennvirginia.com. We make available free of charge on or through our internet website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Nominating and Governance Committee Charter and

Compensation and Benefits 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 Securities Exchange Act of 1934 (or the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (or the SEC).

Executive Officers of the Company

The following table sets forth information concerning our executive officers. Each officer is elected annually by the Board of Directors and serves at the pleasure of the Board of Directors.

Name	Age	Position with the Company
A. James Dearlove	59	President and Chief Executive Officer
Keith D. Horton	53	Executive Vice President
Ronald K. Page	56	Vice President
Frank A. Pici	51	Executive Vice President and Chief Financial Officer
Nancy M. Snyder	53	Executive Vice President, General Counsel and Corporate Secretary
H. Baird Whitehead	56	Executive Vice President

A. James Dearlove has served as our President and Chief Executive Officer since May 1996 and as a director since February 1996, as our President and Chief Operating Officer from 1994 to May 1996, as our Senior Vice President from 1992 to 1994 and as our Vice President from 1986 to 1992. Mr. Dearlove has also served as Chief Executive Officer and Chairman of the Board of PVG GP, LLC, the general partner of Penn Virginia GP Holdings, L.P., since September 2006 and as Chief Executive Officer and Chairman of the Board of Penn Virginia Resource GP, LLC, the general partner of Penn Virginia Resource Partners, L.P., since July 2001 and December 2002. Mr. Dearlove also serves as a director of the National Council of Coal Lessors.

Keith D. Horton has served as our Executive Vice President and as a director since December 2000, as Vice President—Eastern Operations from February 1999 to December 2000, as Vice President from February 1996 to February 1999, as President of Penn Virginia Coal Company from February 1996 to October 2001, as Vice President of Penn Virginia Coal Company from March 1994 to February 1996, as Vice President of Penn Virginia Resources Corporation from January 1990 to December 1998 and as Manager, Coal Operations of Penn Virginia Resources Corporation from July 1982 to December 1989. Mr. Horton has also served as Co-President and Chief Operating Officer—Coal of Penn Virginia Resource GP, LLC since May 2006 and as President and Chief Operating Officer of Penn Virginia Resource GP, LLC from July 2001 to May 2006. Mr. Horton has also served as President of Penn Virginia Operating Co., LLC since September 2001. Mr. Horton serves as a director of the Virginia Mining Association, the Powell River Project and the Eastern Coal Council.

Ronald K. Page has served as our Vice President since May 2005 and as our Vice President, Corporate Development from July 2003 to May 2005. Mr. Page has also served as Co-President and Chief Operating Officer—Midstream of Penn Virginia Resource GP, LLC since May 2006 and as Vice President, Corporate Development of Penn Virginia Resource GP, LLC from July 2003 to May 2006. Mr. Page has also served as President of PVR Midstream LLC since January 2005. From January 1998 to May 2003, Mr. Page served in various positions with El Paso Field Services Company, including Vice President of Commercial Operations—Texas Pipelines and Processing from 2001 to 2003, Vice President of Business Development from 2000 to 2001 and Director of Business Development from 1999 to 2000.

Frank A. Pici has served as our Executive Vice President and Chief Financial Officer since September 2001. Mr. Pici has also served as Vice President and Chief Financial Officer and as a director of PVG GP, LLC since September 2006 and as Vice President and Chief Financial Officer and as a director of Penn Virginia Resource GP, LLC since September 2001 and October 2002. From 1996 to 2001, Mr. Pici served as Vice President—Finance and Chief Financial Officer of Mariner Energy, Inc., or Mariner, a Houston, Texas-based oil and gas exploration and production company, where he managed all financial aspects of Mariner, including accounting, tax, finance, banking, investor relations, planning and budgeting and information technology. From 1994 to 1996, Mr. Pici served as Corporate Controller of Cabot Oil & Gas Corporation, or Cabot, an oil and gas exploration and production company, from 1984 to 1989.

Nancy M. Snyder has served as our Executive Vice President since May 2006, as our Senior Vice President from February 2003 to May 2006, as our Vice President from December 2000 to February 2003 and as our General Counsel and Corporate Secretary since 1997. Ms. Snyder has also served as Vice President and General Counsel and as a director of PVG GP, LLC since September 2006 and as Vice President and General Counsel and as a director of Penn Virginia Resource GP, LLC since July 2001. From 1993 to 1997, Ms. Snyder was a solo practitioner representing clients generally in connection with mergers and acquisitions and general corporate matters.

H. Baird Whitehead has served as our Executive Vice President since January 2001 and as President of Penn Virginia Oil & Gas Corporation since January 2001. Prior to joining the Company, Mr. Whitehead served in various positions with Cabot. From 1998 to 2001, Mr. Whitehead served as Senior Vice President during which time he oversaw Cabot's drilling, production and exploration activity in the Appalachian, Rocky Mountain, Mid-Continent and Gulf Coast areas. From 1992 to 1998, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Appalachian business. From 1989 to 1992, Mr. Whitehead served as Vice President and Regional Manager of Cabot's Anadarko business unit.

Common Abbreviations and Definitions

The following terms have the meanings indicated below when 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
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
MMbbl—	one million barrels
MMbf—	one million board feet

MMbtu—	one million British thermal units
MMcf—	one million cubic feet
MMcfe—	one million cubic feet equivalent
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 farther apart 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 developed reserves—	reserves that can be expected to be recovered through existing wells with existing equipment and operating methods
Proved reserves—	those 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 undeveloped reserves—	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
Proven coal reserves—	those reserves for which: (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely, and the geologic character is so well defined, that 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 prices in effect at a fiscal year end 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 uncertainty 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), 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 through acquisitions, exploration and development. 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. Lower 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 become limited or unavailable. 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, including acquisitions that would be significantly larger than those we have consummated to date. 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. We cannot ensure that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any 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. Our capital expenditures for oil and gas properties were $338.5 million for 2006, and we have budgeted total capital expenditures of $310 million to $345 million in 2007. 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. Debt or equity financing, cash generated by operations or borrowing capacity may not be available to us in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will 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.

Issuing equity securities to satisfy our financing requirements could cause substantial dilution to existing shareholders. Debt financing could lead to us being more vulnerable to competitive pressures and economic downturns.

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 our credit facility 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 on 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 for activity within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our results of operations and 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.

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 affect on our financial condition and operations.

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 of 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, 2006, approximately 29% 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 flow 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.

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

Other companies operate a portion of our net production. In 2006, other companies operated approximately 28% 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.

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. The success of any acquisition 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.

Responses to recent coal mining accidents could have an adverse effect on our operations.

Our conventional and CBM drilling operations in Appalachia take place in close proximity to coal mining operations. Recent coal mining disasters in West Virginia and Kentucky have received state and national attention that is resulting in increased scrutiny of current safety practices and procedures at and around coal mining operations. This scrutiny could result in the promulgation of more stringent regulations for the permitting of oil and gas wells in close proximity to coal mining operations, which could make it more difficult, time consuming and costly for us to obtain such permits and could adversely affect our natural gas production and reduce our oil and natural gas revenues.

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

In order to manage our exposure to price risks in the marketing 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. We cannot assure you that our hedging transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices.

In addition, hedging 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, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging 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 and 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 financial condition and 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

PVG's ability to make distributions to us is entirely dependent upon PVG's 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 gas midstream businesses.

If PVG had completed its initial public offering on January 1, 2006, assuming its current distribution level, we would have received $30.8 million of distributions from PVG in 2006. 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 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 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;

- the lessees' timely receipt of payment from their customers;
- the amount of natural gas transported in its gathering systems;
- the amount of throughput in its processing plants;
- the price of natural gas;
- the price of NGLs;
- the relationship between natural gas and NGL prices;
- the fees it charges and the margins it realizes for its 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, some of which are beyond its control, 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. You should also be aware that 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.

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:

- restrictions on distributions contained in any future debt agreements;
- PVG's estimated general and administrative expenses, including expenses it will incur as a result of being a public company 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 2% general partner interest in PVR, as required by PVR's partnership agreement upon the issuance of additional partnership securities by PVR; and
- 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.

A portion of PVG's partnership interests in PVR are subordinated to PVR's common units, which would result in decreased distributions by PVR to PVG and, consequently, could result in decreased distributions from PVG to its unitholders, including us, if PVR is unable to meet its minimum quarterly distribution.

PVG owns 19,587,049 units representing limited partner interests in PVR, of which approximately 79.3% are common units and 20.7% are Class B units. Currently, the Class B units will not receive any distributions in a quarter until PVR has paid the minimum quarterly distribution of $0.25 per PVR unit, plus any arrearages in the payment of the minimum quarterly distribution from prior quarters, on all of the outstanding PVR common units. Distributions on the Class B units are, therefore, more uncertain than distributions on PVR's common units. Furthermore, no distributions may be made on the incentive distribution rights until the minimum quarterly distribution has been paid on all outstanding PVR units. Therefore, distributions with respect to the incentive distribution rights are even more uncertain than distributions on the Class B units. Neither the Class B units nor the incentive distribution rights are entitled to any arrearages from prior quarters.

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's ownership of the incentive distribution rights in PVR, through PVG's ownership interests in PVR's general partner, the holder of the incentive distribution rights, entitles PVG to receive its pro rata share of specified percentages of total cash distributions made by PVR with respect to any particular quarter only in the event that PVR distributes more than $0.275 per unit for such quarter. As a result, the holders of PVR's common units and Class B units have a priority over the holders of PVR's incentive distribution rights to the extent of cash distributions by PVR up to and including $0.275 per unit for any quarter.

PVG's incentive distribution rights entitle it to receive increasing percentages, up to 48%, of all cash distributed by PVR. Because PVG is at the maximum target cash distribution level on the incentive distribution rights, future growth in distributions PVG receives from PVR, and in distributions we receive from PVG, will not result from an increase in the target cash distribution level associated with the incentive distribution rights. Furthermore, 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 48% to 23%, consequently, resulting in less cash available to PVG to distribute to its unitholders, including us.

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 interests, incentive distribution rights and the limited partner interests that PVG holds. Because a majority of the cash PVG receives from PVR is attributable to PVG's ownership of the incentive distribution rights, 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.

Our ability to sell our common units of PVG, and PVG's ability to sell its partnership interests in PVR, may be limited by securities law restrictions and liquidity constraints.

We own 32,087,424 common units of PVG and PVG owns 15,541,738 common units and 4,045,311 Class B units of PVR, all of which are unregistered and restricted securities within the meaning of Rule 144 under the Securities Act of 1933. Unless we or PVG were to register these units, we or PVG are limited to selling into the market in any three-month period an amount of PVG common units or PVR common units that does not exceed the greater of 1% of the total number of common units outstanding or the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale. Furthermore, there is no public market for PVR's Class B units and we do not expect one to develop. If PVG were required to sell Class B units for any reason, it likely would receive a discount to the current market price of PVR's common units, and that discount may be substantial. In addition, PVG faces contractual limitations on its ability to sell its general partner interest and incentive distribution rights in PVR and the market for such interests is illiquid.

Risks Related to PVR's Coal Business

If PVR's lessees do not manage their operations well, their production volumes and PVR's coal royalty 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 wages;
- permitting;
- surety bonding; and
- mine closure and reclamation.

If PVR's lessees do not manage their operations well, their production could be reduced, which would result in lower coal royalty revenues to PVR and could adversely affect PVR's ability to make its quarterly distributions.

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

PVR's coal royalty 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 royalty revenues and adversely affect its ability to make its quarterly distributions. In addition, PVR's coal royalty 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 adversely affect PVR's ability to make its quarterly distributions.

A substantial or extended decline in coal prices could reduce PVR's coal royalty 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 and on the quantities of coal that may be economically produced from its properties. This, in turn, could reduce PVR's coal royalty revenues, its 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.

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

PVR depends on a limited number of primary operators for a significant portion of its coal royalty revenues. During 2006, five primary operators, each with multiple leases, accounted for 78% of PVR's coal royalty revenues and 12% of our total consolidated revenues. If any of these operators enters bankruptcy or decide to cease operations or significantly reduce its production, PVR's coal royalty revenues could 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 its 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. If PVR is unable to negotiate purchase contracts to replace or increase its coal reserves on acceptable terms, its coal royalty revenues will decline as its coal reserves are depleted. In addition, if PVR is unable to successfully integrate the companies, businesses or properties it is able to acquire, its coal royalty revenues may decline and PVR could, therefore, experience a material adverse effect on its business, financial condition or results of operations. If PVR acquires 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 royalty payments.

PVR does not control its lessees' business operations. Its 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 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 royalty 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.

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 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 royalty revenues to PVR.

PVR's lessees could experience labor disruptions, and PVR's lessees' workforces could become increasingly unionized in the future.

Two of PVR's lessees each have one mine operated by unionized employees. One of these mines was PVR's second largest mine on the basis of coal production as of December 31, 2006. 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 reserves and reduce its coal royalty 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 royalty revenues.

According to the U.S. Department of Energy, domestic electric power generation accounts for approximately 90% of domestic coal consumption. 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 Clean Air Act 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 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 royalty 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. There is also continuing pressure on state and federal regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. 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 royalty revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal Segment—Air Emissions."

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 royalty 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 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, or may not be issued or renewed in a timely fashion, or may involve requirements that restrict its 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 could have an adverse effect on its coal royalty revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal Segment—Mining Permits and Approvals."

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 royalty 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 royalty revenues. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal 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 royalty revenues and its ability to make distributions, could be adversely affected.

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. See Item 1, "Business—Government Regulation and Environmental Matters—PVR Coal Segment—Mine Health and Safety Laws," for a more detailed discussion of recently enacted legislation that addresses mine safety equipment, training and emergency reporting requirements. Implementing and complying with these new laws and regulations could adversely affect PVR's lessees' coal production and could therefore have an adverse affect on PVR's coal royalty revenues and its ability to make distributions.

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 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 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 access 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.

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 2006, 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—percentage-of-proceeds and keep-whole arrangements. See Item 1, "Business—Contracts—PVR Natural Gas Midstream Segment."

Virtually all of the natural gas gathered on PVR's Crescent System and Hamlin System is contracted under percentage-of-proceeds arrangements. The natural gas gathered on PVR's Beaver System is contracted 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 upon an index price for the gas and the price received for the NGLs. Under these percentage-of-proceeds 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 results of operations. 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 results of operations.

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 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 compliment its existing operations. 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 may require substantial capital or the incurrence of substantial indebtedness. As a result, PVR's capitalization and results of operations may change significantly following an acquisition, and you will not have the opportunity to evaluate the economic, financial and other relevant information that PVR will consider in determining the application of these funds and other resources. Future PVR acquisitions might not generate increases in PVR's pro forma available cash per unit, and may not increase cash distributions to PVR's unitholders.

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

One of the ways PVR may grow its 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. If PVR undertakes these projects, they may not be completed on schedule, or at all, or at the budgeted 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 adversely affect its financial position or results of operations and its ability to make distributions.

If PVR is unable to obtain new rights-of-way or the cost of renewing existing rights-of-way increases, then it 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 it 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 midstream customers, and nonpayment or nonperformance by PVR's customers could reduce its cash flows.

PVR is subject to risk of loss resulting from nonpayment or nonperformance by its midstream customers. PVR depends on a limited number of customers for a significant portion of its midstream revenue. For 2006, two customers represented 49% of total natural gas midstream revenues and 26% of our total consolidated revenues. Any nonpayment or nonperformance by our midstream customers could reduce our 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 would adversely affect its revenues and cash flow.

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 its midstream facilities. Similarly, if additional shippers begin transporting volumes of residue gas and NGLs on interconnecting pipelines, PVR's allocations in these pipelines would be reduced. Any reduction in volumes gathered and processed in PVR's facilities would adversely affect its revenues and cash flow.

Natural gas hedging 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 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 transactions may limit PVR's potential gains if natural gas or NGL prices were to rise over the price established by the hedging arrangements. 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. PVR's hedging transactions may not reduce the risk or minimize the effect of any decline in natural gas or NGL prices.

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

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

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging 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.

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

PVR's 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 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 operations. PVR is not fully insured against all risks incident to its 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 operations and 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 natural gas company 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 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 systems, 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.

PVR's 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 Cantera or locations to which it has 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 midstream business due to its handling of natural gas and other petroleum products, air emissions related to its midstream operations, historical industry operations, waste disposal practices and Cantera's prior use 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."

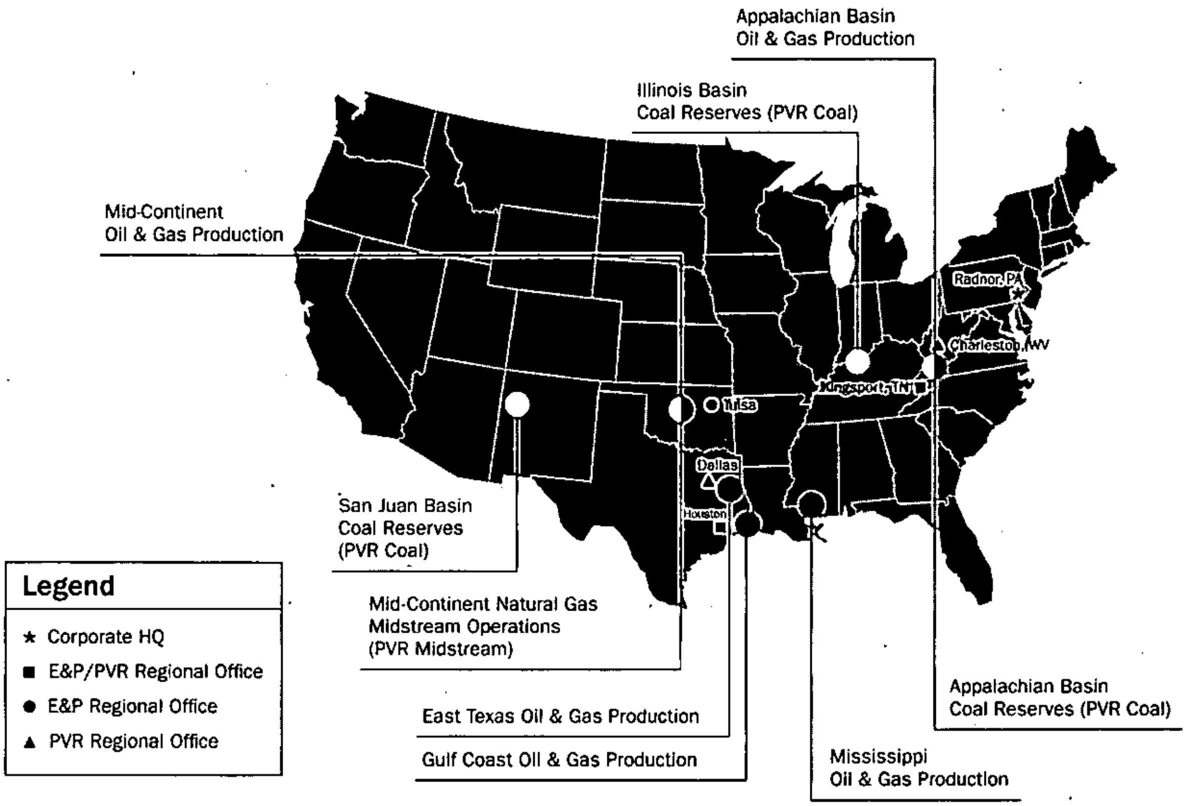
Item 1B *Unresolved Staff Comments*

We received no written comments from the SEC staff regarding our periodic or current reports under the Exchange Act within 180 days before the end of our fiscal year ended December 31, 2006.

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:



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 gas midstream industries.

Facilities

We are headquartered in Radnor, Pennsylvania, with additional offices in 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 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 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.

Production and Pricing

The following table sets forth production, average sales prices and production costs with respect to our oil and gas properties for the years ended December 31, 2006, 2005 and 2004:

	2006	2005	2004
Production			
Oil and condensate (MBbls)	382	302	396
Natural gas (MMcf)	28,968	25,550	22,079
Total production (MMcfe)	31,260	27,362	24,455
Average realized prices			
Natural gas ($/Mcf):			
Natural gas revenue, as reported	$ 7.35	$ 8.31	$ 6.27
Derivatives (gains) losses included in natural gas revenues	(0.02)	0.55	0.17
Natural gas revenue before impact of derivatives	7.33	8.86	6.44
Cash settlements on natural gas derivatives	0.37	(0.55)	(0.17)
Natural gas revenues, adjusted for derivatives	$ 7.70	$ 8.31	$ 6.27
Crude oil ($/Bbl):			
Crude oil revenue, as reported	$ 55.59	$ 45.67	$ 33.75
Derivatives (gains) losses included in oil and condensate revenues	1.20	2.84	5.34
Oil and condensate revenue before impact of derivatives	56.79	48.51	39.09
Cash settlements on crude oil derivatives	(0.52)	(2.84)	(5.34)
Oil and condensate revenues, adjusted for derivatives	$ 56.27	$ 45.67	$ 33.75
Production expenses ($/Mcfe)			
Lease operating	$ 0.88	$ 0.63	$ 0.57
Taxes other than income	0.38	0.48	0.38
General and administrative	0.41	0.34	0.34
Total production expenses	$ 1.66	$ 1.45	$ 1.29

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2006, 2005 and 2004. The proved reserve estimates presented below were prepared by Wright and Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves, the preparation of such estimates by Wright and Company, Inc. and other information about our oil and gas reserves, see Note 23 in the Notes to Consolidated Financial Statements. Our estimates of proved reserves in the table below are consistent with those filed by us with other federal agencies.

	Oil and Condensate	Natural Gas	Natural Gas Equivalents	Standardized Measure(1)	Year-end Prices Used	
	(MMbbls)	(Bcf)	(Bcfe)	($ millions)	$ / Bbl	$ /MMbtu
2006						
Developed	3.0	326	345	$ 545		
Undeveloped	1.9	131	142	60		
Total	4.9	457	487	$ 605	$61.05	$ 5.64
2005						
Developed	2.0	267	279	$ 833		
Undeveloped	0.9	92	98	203		
Total	2.9	359	377	$1,036	$61.04	$10.08
2004						
Developed	2.9	243	261	$ 469		
Undeveloped	3.4	73	93	121		
Total	6.3	316	354	$ 590	$43.46	$ 6.18

(1) Standardized measure consists of future net cash flows, discounted at 10%. For information on the changes in the standardized measure of discounted future net cash flows, see Note 23 in the Notes to Consolidated Financial Statements.

In accordance with the SEC's guidelines, the engineers' estimates of future net revenues from our properties and the standardized measure thereof are based on oil and natural gas sales prices in effect as of December 31, 2006, and estimated future costs as of December 31, 2006. 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. 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 natural gas, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known 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. There are numerous uncertainties inherent in estimating quantities of proved 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.

Acreage

The following table sets forth our developed and undeveloped acreage at December 31, 2006. The acreage is located primarily in the Appalachian, Mississippi, Mid-Continent and Gulf Coast onshore areas of the United States.

	Gross Acreage	Net Acreage
	(in thousands)	
Developed	653	517
Undeveloped	829	550
Total	1,482	1,067

Wells Drilled

The following table sets forth the gross and net numbers of exploratory and development wells we drilled during the last three years. The number of wells drilled refers to the number of wells reaching total depth at any time during the respective year. Net wells equals the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells which were producing or which were capable of commercial production.

	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	187	138.9	163	130.8	134	89.7
Non-Productive	3	2.4	3	3.0	1	0.3
Total development	190	141.3	166	133.8	135	90.0
Exploratory						
Productive	13	7.2	6	2.9	7	1.5
Non-productive	6	2.3	3	3.0	7	4.4
Under evaluation	1	1.0	3	2.5	3	2.6
Total exploratory	20	10.5	12	8.4	17	8.5
Total	210	151.8	178	142.2	152	98.5

The exploratory well under evaluation at the end of 2006 was a Cotton Valley well in Texas. We expect to determine the commercial viability of this well during 2007. At December 31, 2006, we had capitalized costs of $1.1 million related to this well.

The three exploratory wells under evaluation at the end of 2005 included two New Albany Shale wells in Illinois and a Bakken Dolomite horizontal oil well in Montana. In 2006, we determined that these wells were not commercially viable, resulting in a $3.8 million write-off.

The three exploratory wells under evaluation at the end of 2004 included a horizontal Devonian shale well in West Virginia, a CBM well in Mississippi and an horizontal CBM well in Virginia. In 2005, we determined that these wells were not commercially viable, resulting in a $3.3 million write-off.

Productive Wells

The number of productive oil and gas wells in which we had a working interest at December 31, 2006 is set forth below. Productive wells are producing wells or wells capable of commercial production.

Operated Wells		Non-Operated Wells		Total	
Gross	Net	Gross	Net	Gross	Net
1,192	1,092.8	847	128.0	2,039	1,220.8

In addition to the above working interest wells, we own royalty interests in 2,876 gross wells.

Coal Reserves and Production

As of December 31, 2006, PVR owned or controlled approximately 765 million tons of proven and probable coal reserves located on approximately 379,000 acres (including fee and leased acreage) in 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 Buchanan, Lee and Wise Counties, Virginia; Floyd, Harlan, Knott and Letcher Counties, Kentucky; and Boone, Fayette, Kanawha, Lincoln, Logan and Raleigh Counties, West Virginia;
- Northern Appalachia Basin: properties located in Barbour, Harrison, Lewis, Monongalia and Upshur Counties, West Virginia;
- San Juan Basin: properties located in McKinley County, New Mexico; and
- Illinois Basin: properties located in Henderson and Webster Counties, Kentucky.

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 reserves are defined as follows:

Proven Coal Reserves. Proven coal reserves are coal 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 coal 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 reserves are high in energy content, low in sulfur and suitable for either the steam or 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 production data and reserve information with respect to each of PVR's properties:

Property	Year Ended December 31, 2006	2005	2004
	(tons in millions)		
Central Appalachia	20.2	19.0	20.1
Northern Appalachia	5.0	5.0	5.6
Illinois Basin	2.5	1.4	—
San Juan Basin	5.1	4.8	5.5
Total	32.8	30.2	31.2

Property	Proven and Probable Reserves at December 31, 2006 Under-ground	Surface	Total	Steam	Metallurgical	Total
	(tons in millions)					
Central Appalachia	425.3	133.6	558.9	459.0	99.9	558.9
Northern Appalachia	33.8	2.2	36.0	36.0	—	36.0
Illinois Basin	99.6	13.0	112.6	112.6	—	112.6
San Juan Basin	—	57.9	57.9	57.9	—	57.9
Total	558.7	206.7	765.4	665.5	99.9	765.4

The following table sets forth the coal reserves PVR owns and leases with respect to each of its coal properties as of December 31, 2006:

Property	Owned	Leased	Total
	(tons in millions)		
Central Appalachia	422.7	136.2	558.9
Northern Appalachia	36.0	—	36.0
Illinois Basin	112.6	—	112.6
San Juan Basin	54.0	3.9	57.9
Total	625.3	140.1	765.4

PVR's coal reserve estimates were prepared from geological data assembled and analyzed by PVR's general partner's geologists and engineers. These estimates are compiled using geological data taken from thousands of drill holes, geophysical logs, adjacent mine workings, outcrop prospect openings and other sources. These estimates also take into account legal, qualitative, technical and economic limitations that may keep coal from being mined. Coal reserve estimates will change from time to time due to mining activities, analysis of new engineering and geological data, acquisition or divestment of reserve holdings, modification of mining plans or mining methods and other factors.

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. The facilities provide efficient methods to enhance lessee production levels and exploit PVR's reserves. Historically, the majority of these fees have been generated by PVR's unit train loadout facility on its Central Appalachia property, which accommodates 108 car unit trains that can be loaded in approximately four hours. Some of PVR's lessees utilize the unit train loadout facility to reduce the delivery costs incurred by their customers. The coal service facility PVR purchased in November 2002 on its Coal River property in West Virginia began operations late in the third quarter of 2003. In the first quarter of 2004, PVR placed into service a newly constructed coal loadout facility for another lessee in West Virginia for $4.4 million. In September 2006, PVR completed construction of a new preparation and loading facility on property it acquired in 2005 in eastern Kentucky.

Natural Gas Midstream Systems

PVR's midstream operations currently include three natural gas gathering and processing systems and a standalone natural gas gathering system, including: (i) the Beaver/Perryton gathering and processing facilities in the Texas/Oklahoma panhandle area, (ii) the Crescent gathering and processing facilities in central Oklahoma, (iii) the Hamlin gathering and processing facilities in west-central Texas and (iv) the Arkoma gathering system in eastern Oklahoma. These systems include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities, which have 160 MMcfd of total capacity. 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 midstream facilities are located.

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

Asset	Type	Approximate Length (Miles)	Approximate Wells Connected	Current Processing Capacity (Mmcfd)	Year Ended December 31, 2006: Average System Throughput (Mmcfd)	Year Ended December 31, 2006: Utilization of Processing Capacity (%)
Beaver/Perryton System	Gathering pipelines and processing facility	1,377	934	100	113.0(1)	100.0%
Crescent System	Gathering pipelines and processing facility	1,679	888	40	18.4	46.0%
Hamlin System	Gathering pipelines and processing facility	497	231	20	7.2	36.0%
Arkoma System	Gathering pipelines	78	78	—	14.7(2)	
		3,631	2,131	160	153.3(3)	

(1) Includes gas processed at other systems connected to the Beaver/Perryton System via the pipeline acquired in June 2006.

(2) Gathering only volumes.

(3) Total average system throughput would be 163 MMcfd if the acquisition of additional pipeline in June 2006 had occurred on January 1, 2006.

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 *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to a vote of security holders during the fourth quarter of 2006.

PART II

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

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "PVA." The high and low sales prices (composite transactions) and dividends paid for each fiscal quarter in 2006 and 2005 were as follows:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2006	$76.70	$59.74	$0.1125
September 30, 2006	$72.65	$60.28	$0.1125
June 30, 2006	$77.21	$59.80	$0.1125
March 31, 2006	$72.45	$56.59	$0.1125
December 31, 2005	$62.76	$51.15	$0.1125
September 30, 2005	$58.40	$44.59	$0.1125
June 30, 2005	$49.32	$38.05	$0.1125
March 31, 2005	$50.52	$37.55	$0.1125

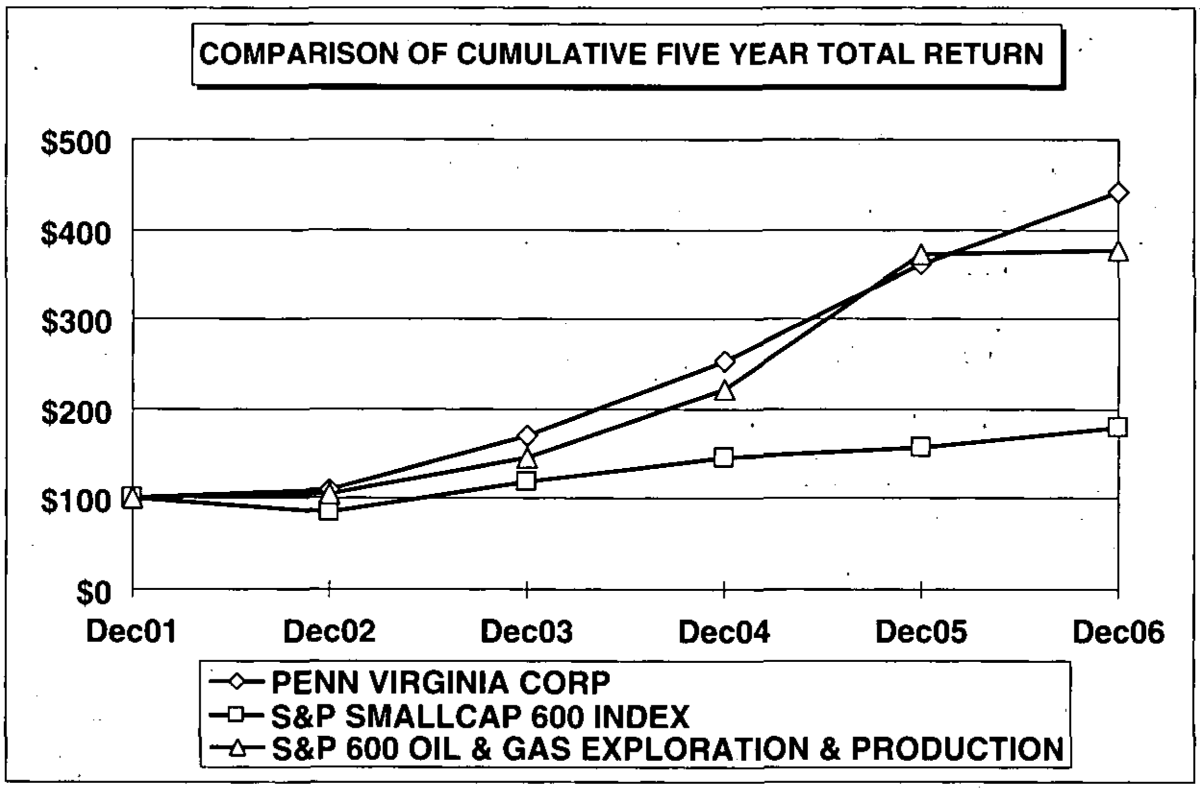
Equity Holders

As of February 21, 2007, there were approximately 570 record holders and approximately 7,400 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 Oil and Gas Exploration & Production 600 Index and the Standard & Poor's SmallCap 600 Index. There are eight companies in the Standard & Poor's Oil and Gas Exploration & Production 600 Index: Cabot Oil & Gas Corporation, Cimarex Energy Co., Helix Energy Solutions Group, Inc., Penn Virginia Corporation, Petroleum Development Corporation, St. Mary Land & Exploration Company, Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2002 in us and each index at December 31, 2001 closing prices.

Comparison of Five-Year Cumulative Total Return
Penn Virginia Corporation, S&P Exploration & Production 600 Index and
S&P SmallCap 600 Index



	2002	2003	2004	2005	2006
Penn Virginia Corporation	109.35	170.96	252.57	360.60	442.80
S&P Smallcap 600 Index	85.37	118.48	145.32	156.48	180.14
S&P Oil & Gas Exploration & Production 600 Index	105.21	146.08	222.57	372.53	375.91

Item 6 *Selected Financial Data*

The following selected historical financial information was derived from our audited financial statements as of December 31, 2006, 2005, 2004, 2003 and 2002, 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 in Item 8, "Financial Statements and Supplementary Data," and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2006	2005 (1)	2004	2003	2002
	(in thousands except share data)				
Revenues	$ 753,929	$ 673,864	$228,425	$181,284	$110,957
Operating income (2)	$ 170,532	$ 162,017	$ 80,796	$ 62,101	$ 30,791
Net income	$ 75,909	$ 62,088	$ 33,355	$ 28,522	$ 12,104
Per common share: (3)					
Net income, basic	$ 4.06	$ 3.35	$ 1.82	$ 1.59	$ 0.68
Net income, diluted	$ 4.02	$ 3.31	$ 1.81	$ 1.58	$ 0.67
Dividends paid	$ 0.45	$ 0.45	$ 0.45	$ 0.45	$ 0.45
Cash flows provided by operating activities	$ 275,819	$ 231,407	$146,365	$109,704	$ 65,788
Total assets (4)	$1,633,149	$1,251,546	$783,335	$683,733	$586,292
Long-term debt, net of current portion	$ 428,214	$ 325,846	$188,926	$154,286	$106,887
Minority interest in PVG	$ 438,372	$ 313,524	$182,891	$190,508	$192,770
Shareholders' equity	$ 382,425	$ 310,308	$252,860	$211,648	$187,956

(1) The 2005 column includes the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition. (as defined in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Acquisitions and Investments")

(2) Operating income in 2004 included a $7.5 million loss on assets held for sale. Operating income in 2006, 2005, 2004, 2003 and 2002 included a $8.5 million, $4.8 million, $0.7 million, $0.4 million and $0.8 million impairment of oil and gas properties.

(3) For comparative purposes, amounts per common share in 2002 and 2003 have been adjusted for the effect of a two-for-one stock split on June 10, 2004.

(4) Total assets in 2006 and 2005 reflect the Cantera Acquisition.

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

The following analysis of financial condition and results of operations of Penn Virginia Corporation and its subsidiaries should be read in conjunction with our consolidated financial statements and the accompanying notes in Item 8, "Financial Statements and Supplementary Data." Our discussion and analysis include the following items:

- Overview of Business
- Acquisitions and Investments
- Current Performance
- Summary of Critical Accounting Policies and Estimates
- Liquidity and Capital Resources
- Contractual Obligations
- Off-Balance Sheet Arrangements
- Results of Operations

- Environmental Matters
- Recent Accounting Pronouncements
- Forward-Looking Statements

Overview of Business

We are an independent energy company that is engaged in three primary business segments: oil and gas, coal and natural gas midstream. We directly operate our oil and gas segment. PVR operates our coal and natural gas midstream segments. We own 100% of the general partner of PVG and an approximately 82% limited partner interest in PVG. PVG owns 100% of the general partner of PVR, which holds a 2% percent general partner interest in PVR, and an approximately 42% limited partner interest in PVR. In 2006, approximately 50% of our operating income was attributable to our oil and gas segment, 43% was attributable to our coal segment and 17% was attributable to our natural gas midstream segment, less a 10% operating loss related to corporate and other functions. A description of each of our reportable segments follows:

Oil and Gas Segment

In our oil and gas segment, we explore for, develop, produce and sell crude oil, condensate and natural gas primarily in the Appalachian, Mississippi, Mid-Continent and Gulf Coast onshore regions of the United States. At December 31, 2006, we had proved oil and natural gas reserves of approximately 5 million barrels of oil and condensate and 457 Bcf of natural gas, or 487 Bcfe. During 2006, three customers accounted for 57% of our oil and gas revenues. Oil and natural gas production from our properties increased to 31.3 Bcfe in 2006, an increase of 14% from 27.4 Bcfe produced in 2005

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 is also highly dependent on the results of our exploratory and development drilling programs.

In addition, to our conventional development program, we have continued to expand our presence in unconventional plays by developing CBM gas reserves in Appalachia. By employing horizontal drilling techniques, we expect to continue to increase the value from the CBM-prospective properties we own. We are committed, to expanding our oil and gas reserves and production primarily by using our ability to generate exploratory prospects and development drilling programs internally.

PVR Coal Segment

As of December 31, 2006, PVR owned or controlled approximately 765 million tons of proven and probable coal reserves in Central and Northern Appalachia, the San Juan Basin and the Illinois Basin. As of December 31, 2006, approximately 87% of PVR's proven and probable coal reserves was "steam" coal used primarily by electric generation utilities, and the remaining 13% was metallurgical coal used primarily by steel manufacturers. PVR enters into long-term leases with experienced, third-party mine operators providing them the right to mine its coal reserves in exchange for royalty payments. PVR does not operate any mines. In 2006, PVR's lessees produced 32.8 million tons of coal from its properties and paid to PVR coal royalty revenues of $98.2 million, for an average gross coal royalty per ton of $2.99. Approximately 84% of PVR's coal royalty revenues in 2006 and 83% of PVR's coal royalty revenues in 2005 were derived from coal mined on its 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 royalty revenues for the respective periods was derived from coal mined on its properties under leases containing fixed royalty rates that escalate annually.

Coal prices, especially in Central Appalachia where the majority of PVR's coal is produced, increased significantly from the beginning of 2004 through most of 2006. The price increase stems from several causes, including increased electricity demand and decreasing coal production in Central Appalachia.

Substantially all of PVR's leases require the lessee to pay minimum rental payments to PVR in monthly or annual installments. PVR actively works with its lessees to develop efficient methods to exploit its reserves and to maximize production from its properties. PVR also earns revenues from providing fee-based coal preparation and transportation services to its lessees, which enhance their production levels and generate additional coal royalty revenues, and from industrial third party coal end-users by owning and operating coal handling facilities through its joint venture with Massey. In addition, PVR earns revenues from oil and gas royalty interests it owns, from wheelage rights and from the sale of standing timber on its properties. During 2006, five lessees accounted for 78% of our coal royalty revenues.

PVR's management continues to focus on acquisitions that increase and diversify its sources of cash flow. During 2006, PVR increased its coal reserves by 96 million tons, or 14%, from its coal reserves as of December 31, 2005, by completing three coal reserve acquisitions in 2006 with an aggregate purchase price of approximately $76 million. For a more detailed discussion of PVR's acquisitions, see "—Acquisitions and Investments."

Coal royalties are impacted by several factors that PVR generally cannot control. The number of tons mined annually is determined by an operator's mining efficiency, labor availability, geologic conditions, access to capital, ability to market coal and ability to arrange reliable transportation to the end-user. The possibility exists that new legislation or regulations have or may be adopted which may have a significant impact on the mining operations of PVR's lessees or their customers' ability to use coal and which may require PVR, its lessees or its lessees' customers to change operations significantly or incur substantial costs. See Item 1A, "Risk Factors."

PVR Natural Gas Midstream Segment

PVR owns and operates midstream assets that include approximately 3,631 miles of natural gas gathering pipelines and three natural gas processing facilities located in Oklahoma and the panhandle of Texas, which have 160 MMcfd of total capacity. PVR's 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 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 acquired its natural gas midstream assets from Cantera in March 2005. PVR's management believes that this acquisition established a platform for future growth in the natural gas midstream sector and diversified its cash flows into another long-lived asset base. Since acquiring these assets, PVR has expanded its natural gas midstream business by adding 181 miles of new gathering lines.

For the year ended December 31, 2006, inlet volumes at PVR's gas processing plants and gathering systems were 56.0 Bcf, or approximately 153 MMcfd. During 2006, two customers accounted for 49% of our natural gas midstream revenues.

PVR continually seeks new supplies of natural gas to both offset the natural declines in production from the wells currently connected to its systems and to increase throughput volume. New natural gas supplies are obtained for all of PVR's systems by contracting for production from new wells, connecting new wells drilled on dedicated acreage and by contracting for natural gas that has been released from competitors' systems.

Revenues, profitability and the future rate of growth of the natural gas midstream segment are highly dependent on market demand and prevailing NGL and natural gas prices. Historically, changes in the prices of most NGL products have generally correlated with changes in the price of crude oil. NGL and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for NGL products and natural gas market uncertainty.

Corporate and Other

Corporate and other primarily represents corporate functions.

Ownership of and Relationship with PVG and PVR

Penn Virginia, PVG and PVR are publicly traded on the New York Stock Exchange under the symbols "PVA," "PVG" and "PVR." Because we control of the general partner of PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVG include those of PVR. However, PVG and PVR function with a capital structure that is 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. The diagram in Item 1, "Business—Corporate Structure" depicts our ownership of PVG and PVR as of December 31, 2006. While we report consolidated financial results of PVR's coal and natural gas midstream businesses, the only cash we received from those businesses is in the form of cash distributions from PVG.

Prior to the PVG IPO in December 2006, we indirectly owned common units representing an approximately 37% limited partner interest in PVR, as well as the sole 2% general partner interest and all of the incentive distribution rights in PVR. We received total distributions from PVR of $28.3 million and $21.2 million in 2006 and 2005, as shown in the following table (in thousands):

	Year Ended December 31,	
	2006	2005
Limited partner units	$22,799	$19,281
General partner interest (2%)	1,254	1,021
Incentive distribution rights	4,273	910
Total	$28,326	$21,212

In conjunction with the PVG IPO, we contributed our limited partner interest and general partner interest, including our incentive distribution rights, in PVR to PVG in exchange for a limited partner interest and the general partner interest in PVG. PVG also purchased additional common units and Class B units of PVR with the proceeds of the PVG IPO. Consequently, PVG is currently entitled to receive certain cash distributions payable with respect to the common and Class B units of PVR, the 2% general partner interest in PVR and the incentive distribution rights in PVR.

We are entitled to receive quarterly cash distributions from PVG on our limited partner interest. Unlike with respect to PVR, PVG's general partner, which is a wholly owned subsidiary of us, does not have an economic interest in PVG and does not have any incentive distribution rights.

Acquisitions and Investments

Oil and Gas Segment

Crow Creek Acquisition. In June 2006, we acquired 100% of the capital stock of Crow Creek Holding Corporation, or Crow Creek, in a cash transaction for approximately $71.5 million. The preliminary purchase price allocation is subject to certain adjustments that primarily relate to the determination of tax basis and the allocation between proved and unproved property. Crow Creek was a privately owned independent exploration and production company with operations primarily in the Oklahoma portions of the Arkoma and Anadarko Basins. The Crow Creek assets primarily included approximately 42.7 Bcfe of net proved reserves, approximately 85% of which were natural gas. The acquisition was funded with long-term debt under our revolving credit facility.

Panther Acquisition. In June 2005, we acquired approximately 60,000 acres of prospective CBM leasehold rights in Wyoming County, West Virginia, from Panther Energy Company, LLC, for $13.3 million in cash. The leasehold acreage is within an area of mutual interest between Penn Virginia and CDX Gas, LLC, or CDX, and is contiguous to acreage which has been successfully developed. The purchase agreement included an option for CDX to purchase a 50% interest in the leasehold acreage. In August 2005, CDX exercised that option and acquired its 50% interest for $6.6 million in cash. We began drilling on the new leasehold position in the fourth quarter of 2005.

PVR Coal Segment

LG&E Acquisition. In December 2006, PVR acquired ownership and lease rights to approximately 22 million tons of coal reserves. The reserves are located in Henderson County, Kentucky. The purchase price was $9.3 million and was funded with cash.

Coal Infrastructure Construction. In September 2006, PVR completed construction of a new 600-ton per hour coal processing plant and rail loading facility for one of its lessees located in Knott County in eastern Kentucky. The facility began operations in October 2006. Since acquiring fee ownership and lease rights to the property's coal reserves in July 2005, PVR made cumulative capital expenditures of $15.4 million related to the construction of the facility.

Huff Creek Acquisition. In May 2006, PVR acquired the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Boone, Logan and Wyoming Counties, West Virginia. The purchase price was $65.0 million and was funded with long-term debt under PVR's revolving credit facility.

Green River Acquisition. In July 2005, PVR acquired fee ownership of approximately 94 million tons of coal reserves in located along the Green River the western Kentucky portion of the Illinois Basin for $62.4 million in cash and the assumption of $3.3 million of deferred income. This coal reserve acquisition was PVR's first in the Illinois Basin and was funded with long-term debt under PVR's revolving credit facility. Currently, approximately 41 million tons of these coal reserves are leased to affiliates of Peabody. PVR expects the remaining coal reserves to be leased over the next several years, with a gradual increase in coal production and related cash flow from the property.

Wayland Acquisition. In July 2005, PVR acquired a combination of fee ownership and lease rights to approximately 16 million tons of coal reserves for $14.5 million. The reserves are located in the eastern Kentucky portion of Central Appalachia. The acquisition was funded with $4.0 million of cash and the issuance by PVR to the seller of approximately 209,000 common units.

Alloy Acquisition. In April 2005, PVR acquired fee ownership of approximately 16 million tons of coal reserves for $15.0 million in cash. The reserves, located near Alloy, West Virginia on approximately 8,300 acres in the central Appalachia region of West Virginia, will be produced from deep and surface mines. Production started in late 2005. Revenues were earned initially from wheelage fees on coal mined from an adjacent property, followed by royalty revenues as the mines on PVR's property commenced production. The seller remained on the property as the lessee and operator. The acquisition was funded with long-term debt under PVR's revolving credit facility.

Coal River Acquisition. In March 2005, PVR acquired lease rights to approximately 36 million tons of undeveloped coal reserves and royalty interests in 73 producing oil and natural gas wells for $9.3 million in cash. The coal reserves are located in the Central Appalachia region of West Virginia. The oil and gas wells are located in eastern Kentucky and southwestern Virginia. The acquisition was funded with long-term debt under PVR's revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with PVR's adjacent reserves and a related loadout facility that was placed into service in 2004. The oil and gas property contained approximately 2.8 Bcfe of net proved oil and gas reserves with current net production of approximately 0.2 Bcfe on an annualized basis.

Coal Handling Joint Venture. In July 2004, PVR acquired from affiliates of Massey a 50% interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded with long-term debt under PVR's revolving credit facility. The joint venture owns coal handling facilities which unload shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019. PVR recognized equity earnings of $1.3 million in 2006, $1.1 million in 2005 and $0.4 million in 2004 related to its ownership in the joint venture. PVR received joint venture distributions of $2.7 million in 2006, $2.3 million in 2005 and $1.0 million in 2004.

PVR Natural Gas Midstream Segment

Transwestern Acquisition. In June 2006, PVR completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma. These assets are contiguous to PVR's Beaver/Perryton System. PVR paid $14.7 million in cash for the acquisition. Subsequently, PVR borrowed $14.7 million under its revolving credit facility to replenish the cash used for the acquisition.

Cantera Acquisition. In March 2005, PVR completed its acquisition of Cantera, a midstream gas gathering and processing company with primary locations in the Mid-Continent area of Oklahoma and the panhandle of Texas. Cash paid in connection with the acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with long-term debt under its revolving credit facility. PVR used the proceeds from its sale of common units in a subsequent public offering in March 2005 to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. See Note 4 in the Notes to Consolidated Financial Statements for pro forma financial information.

Current Performance

Operating income for 2006 was $170.5 million. The oil and gas segment, combined with the operating results of corporate, contributed $67.7 million to operating income, and PVR's coal and natural gas midstream segments contributed $102.8 million, before the deduction of the 58% interest in PVR's and PVG's net income to which we do not own rights. The following table presents a summary of certain financial information relating to our segments (in thousands):

	Oil and Gas	PVR Coal	PVR Midstream	Corporate and Other	Consolidated
For the Year Ended December 31, 2006:					
Revenues	$235,956	$112,981	$404,910	$ 82	$753,929
Operating costs and expenses	94,886	19,138	358,440	16,716	489,180
Depreciation, depletion and amortization	56,237	20,399	17,094	487	94,217
Operating income (loss)	$ 84,833	$ 73,444	$ 29,376	$(17,121)	$170,532
For the Year Ended December 31, 2005:					
Revenues	$226,819	$ 95,755	$350,593	$ 697	$673,864
Operating costs and expenses	80,669	16,121	321,509	11,826	430,125
Impairment of oil and gas properties	4,785	—	—	—	4,785
Depreciation, depletion and amortization	45,885	17,890	12,738	424	76,937
Operating income (loss)	$ 95,480	$ 61,744	$ 16,346	$(11,553)	$162,017
For the Year Ended December 31, 2004:					
Revenues	$151,672	$ 75,630	$ —	$ 1,123	$228,425
Operating costs and expenses	57,668	16,479	—	10,334	84,481
Impairment of oil and gas properties	655	—	—	—	655
Loss on assets held for sale	7,541	—	—	—	7,541
Depreciation, depletion and amortization	35,886	18,632	—	434	54,952
Operating income (loss)	$ 49,922	$ 40,519	$ —	$ (9,645)	$ 80,796

Oil and Gas Segment

During 2006, our oil and gas production increased by 14% to 31.3 Bcfe. High commodity prices also contributed significantly to our financial results. Natural gas prices have been volatile recently, with the NYMEX futures market trading at record price levels for natural gas. Our realized natural gas price for 2006 was $7.35 per Mcf, a decrease of 12% from $8.31 per Mcf for 2005. As part of our risk management strategy, we use derivative financial instruments to hedge natural gas and, to a lesser extent, oil prices. The use of this risk management strategy has resulted in lower price realizations compared to physical sale prices in the last several years.

The following table summarizes total natural gas, oil and condensate production and total natural gas, oil and condensate revenues by region:

	Natural Gas, Oil and Condensate Production		Natural Gas, Oil and Condensate Revenues	
	Year Ended December 31,		Year Ended December 31,	
Region	**2006**	**2005**	**2006**	**2005**
	(Mmcfe)		(in thousands)	
Appalachia	12,759	13,812	$ 96,683	$113,360
Mississippi	6,411	5,185	47,801	48,063
Gulf Coast	6,296	5,648	48,596	41,991
East Texas	4,546	2,717	33,656	22,805
Mid-continent	1,248	—	7,420	—
Total	31,260	27,362	$234,156	$226,219

In east Texas, we entered into a joint venture with GMX Resources, Inc. (NASDAQ: GMXR) in 2004 to drill development wells in the North Carthage Field in east Texas. Through December 31, 2006, we drilled 90 gross (62.7 net) wells on this acreage.

In Mississippi, we drilled 80 (79.6 net) successful Selma Chalk development wells were drilled during the year ended December 31, 2006 in the Company's Baxterville, Gwinville and Maxie fields. The first of two horizontal Selma Chalk test wells was drilled in the Gwinville field in Mississippi during the fourth quarter of 2006. The current production rate of the horizontal well is approximately twice that of the adjacent vertical wells. In addition, we began a program in the fourth quarter to test down-spacing the Selma Chalk from 20-acre to 10-acre spacing, which, if successful, would add a significant number of drilling opportunities in our three Selma Chalk fields. Management expects to determine in 2007 whether to pursue horizontal drilling or down-spaced drilling, or both.

In the Gulf Coast region, we participated in the drilling of 17 gross (9.8 net) exploratory wells during the year ended December 31, 2006. Ten (6.5 net) of the wells were successful, six (2.3 net) of the wells were unsuccessful, and the remaining one (1.0 net) well was under evaluation as of December 31, 2006.

In the Mid-Continent region, we completed the Crow Creek Acquisition in June 2006, adding approximately 42.7 Bcfe of net proved reserves in Oklahoma. We began development of the acquired properties and drilled 24 gross (14.7 net) successful horizontal CBM wells and seven gross (2.4 net) conventional well in 2006 since the Crow Creek Acquisition. Another horizontal CBM well (0.4 net) was drilled but plugged and abandoned.

In Appalachia, we continue to expand our CBM production and reserve base through leasehold acquisitions and the use of a proprietary horizontal drilling technology. We drilled 33 gross (14.7 net) horizontal CBM development wells in Appalachia in the year ended December 31, 2006, and all were successful. Production has been temporarily affected by water disposal issues, which has resulted in shutting in or temporarily delaying the first production from nine horizontal patterns.

We drilled a total of 210 gross (151.8 net) wells during the year ended December 31, 2006, including 190 gross (141.3 net) development wells and 20 gross (10.5 net) exploratory wells. All but three gross (2.4 net) development wells were successful. Thirteen exploratory wells (7.2 net) were successful, six exploratory wells (2.3 net) were not successful and one gross and net exploratory well is currently being tested. We have completed testing on three other exploratory wells that were under evaluation as of December 31, 2005 and have determined in 2006 that all three wells were unsuccessful. We wrote off $3.7 million of drilling costs in the third quarter of 2006 related to these wells.

PVR Coal Segment

In 2006, coal royalty revenues increased 19%, or $15.5 million, over 2005 due to acquisitions, more coal being mined by PVR's lessees and increasing coal prices. Tons produced by PVR's lessees increased from 30.2 million tons in 2005 to 32.8 million tons in 2006, and PVR's average gross royalties per ton increased from $2.74 in 2005 to $2.99 in 2006. Generally, as coal prices change, PVR's average royalties per ton also change because the majority of PVR's lessees pay royalties based on the gross sales prices of the coal mined. Most of PVR's coal is sold by its lessees under contracts with a duration of one year or more; therefore, changes to PVR's average royalties occur as PVR's lessees' contracts are renegotiated. The Illinois Basin coal reserves that PVR acquired in July 2005 resulted in $4.8 million of coal royalty revenues in 2006 compared to $2.7 million in 2005. The Huff Creek Acquisition in May 2006 resulted in $4.8 million of coal royalty revenues in 2006.

Coal services revenues increased to $5.9 million in 2006 from $5.2 million in 2005. In September 2006, PVR completed construction of a coal service facility in Knott County, Kentucky, which began operations in October 2006. The new facility contributed $0.2 million to coal services revenues in 2006. PVR believes that these types of fee-based infrastructure assets provide good investment and cash flow opportunities, and they continue to look for additional investments of this type, as well as other primarily fee-based assets.

The following table summarizes coal production and coal royalty revenues by property:

	Coal Production		Coal Royalty Revenues	
	Year Ended December 31,		Year Ended December 31,	
Property	**2006**	**2005**	**2006**	**2005**
	(tons in thousands)		(in thousands)	
Central Appalachia	20,156	18,996	$76,542	$64,645
Northern Appalachia	5,009	4,958	7,314	6,973
Illinois Basin	2,540	1,449	4,768	2,709
San Juan Basin	5,073	4,824	9,539	8,398
Total	32,778	30,227	$98,163	$82,725

PVR Natural Gas Midstream Segment

The gross processing margin for PVR's natural gas midstream operations increased from $44.7 million in 2005 to $68.1 million in 2006. This increase was due primarily to higher NGL prices and the contribution of the Transwestern Acquisition. Inlet volumes at PVR's gas processing plants and gathering systems were 153 MMcfd in 2006, an increase over 127 MMcfd in 2005, primarily due to additional well connections in the area. PVR's 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, 2006 PVR's natural gas midstream business generated a majority of its gross margin from contractual arrangements under which its margin is exposed to increases and decreases in the price of natural gas and natural gas and natural gas liquids or NGLs. See Item 1, "Business—Contracts—PVR Natural Gas Midstream Segment," for a discussion of the types of contracts utilized by the natural gas midstream segement. As part of PVR's risk management strategy, PVR uses derivative financial instruments to economically hedge NGLs sold and natural gas purchased. See the tables in "—Results of Operations—PVR Midstream Segment—Expenses" for the effects of PVR's derivative program on gross processing margin.

PVR's natural gas midstream assets are primarily located in the Mid-Continent area of Oklahoma and the panhandle of Texas. The following table sets forth information regarding PVR's natural gas midstream assets:

Asset	Type	Approximate Length (Miles)	Approximate Wells Connected	Current Processing Capacity (Mmcfd)	Year Ended December 31, 2006 Average System Throughput (Mmcfd)	Year Ended December 31, 2006 Utilization of Processing Capacity (%)
Beaver/Perryton System	Gathering pipelines and processing facility	1,377	934	100	113.0(1)	100.0%
Crescent System	Gathering pipelines and processing facility	1,679	888	40	18.4	46.0%
Hamlin System	Gathering pipelines and processing facility	497	231	20	7.2	36.0%
Arkoma System	Gathering pipelines	78	78	—	14.7(2)	
		3,631	2,131	160	153.3(3)	

(1) Includes gas processed at other systems connected to the Beaver/Perryton System via the pipeline acquired in June 2006.

(2) Gathering only volumes.

(3) Total average system throughput would be 163 MMcfd if the acquisition of additional pipeline in June 2006 had occurred on January 1, 2006

Summary of Critical Accounting Policies and 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.

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 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 those quantities that require additional capital investment through drilling or well recompletion techniques.

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 pursuant to Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* when significant events occur, such as a market move to a lower price environment or a material revision to our reserve estimates.

Depreciation and depletion of oil and gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved recoverable reserves.

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. PVR's estimates of coal reserves are updated periodically and may result in adjustments to coal reserves and depletion rates that are recognized prospectively.

Oil and Gas Revenues

Revenues associated with sales of natural gas, crude oil, condensate and NGLs are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized 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. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded 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, accruals for revenues and accounts receivable are made 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. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Natural Gas Midstream Revenues

Revenues from the sale of NGLs and residue gas are recognized when the NGLs and residue gas produced at PVR's gas processing plants are sold. Gathering and transportation revenues are recognized 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, accruals for revenues and accounts receivable and the related cost of midstream gas purchased and accounts payable are made based on estimates of natural gas purchased and NGLs and natural gas sold, and our financial results include estimates of production and revenues for the period of actual production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received or paid and the original estimates are recorded in the period they become finalized

Coal Royalty Revenues

Coal royalty revenues are recognized 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 mines, it does not have access to actual production and revenue information until approximately 30 days following the month of production. Therefore, the financial results of PVR include estimated revenues and accounts receivable for the month of production. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Derivative Activities

We and PVR have historically entered into derivative financial instruments that would qualify for hedge accounting under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the related hedged transaction settles. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). Because we no longer use hedge accounting for our commodity derivatives, we could experience significant changes in the estimate of derivative gain or loss recognized in revenues and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

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 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 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, 2006, the costs attributable to unproved properties were approximately $100.5 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 relatively 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 expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, Penn Virginia, PVG and PVR operate with independent capital structures. Since PVR's inception in 2001 and PVG's inception in 2006, with the exception of cash distributions paid to us by PVR, the cash needs of each entity have been met independently with a combination of operating cash flows, credit facility borrowings and issuance of new PVR and PVG units. We expect to receive cash distributions from PVG beginning with its first quarterly distribution in 2007. 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.

Summarized cash flow statements for 2006 and 2005, consolidating our combined operating segments, are set forth below.

For the year ended December 31, 2006	Oil and Gas & Corporate	PVR Coal and PVR Midstream	Consolidated
Net cash provided by operating activities	$ 168,475	$ 107,344	$ 275,819
Cash flows from financing activities:			
Dividends paid	(8,398)	—	(8,398)
PVR distributions received (paid)	28,327	(66,954)	(38,627)
Debt borrowings (repayments), net	142,000	(37,100)	104,900
Proceeds from equity issuance	2,810	115,008	117,818
Other	5,623	(375)	5,248
Net cash provided by financing activities	170,362	10,579	180,941
Net cash provided by operating and financing activities	338,837	117,923	456,760
Net cash used in investing activities	(332,659)	(129,676)	(462,335)
Net increase (decrease) in cash and cash equivalents	$ 6,178	$ (11,753)	$ (5,575)

For the year ended December 31, 2005	Oil and Gas & Corporate	PVR Coal and PVR Midstream	Consolidated
Net cash provided by operating activities	$ 137,695	$ 93,712	$ 231,407
Cash flows from financing activities:			
Dividends paid	(8,358)	—	(8,358)
PVR distributions received (paid)	21,212	(51,949)	(30,737)
Debt borrowings (repayments), net	3,000	137,200	140,200
Proceeds from equity issuance	(2,783)	129,239	126,456
Other	1,798	(2,385)	(587)
Net cash provided by financing activities	14,869	212,105	226,974
Net cash provided by operating and financing activities	152,564	305,817	458,381
Net cash used in investing activities	(154,318)	(303,621)	(457,939)
Net increase in cash and cash equivalents	$ (1,754)	$ 2,196	$ 442

Cash Flows

Except where noted, the following discussion of cash flows and capital expenditures relates to our consolidated results.

Cash provided by operating activities in the oil and gas and corporate segments increased $30.8 million, or 22%, to $168.5 million for the year ended December 31, 2006 from $137.7 million for 2005. The overall increase in cash provided by operating activities from the oil and gas and corporate segments in 2006 compared to 2005 was primarily due to increased natural gas and crude oil production. Cash provided by operating activities in the oil and gas and corporate segments increased $46.1 million, or 50%, to $137.7 million for the year ended December 31, 2005 from $91.6 million for 2004. The overall increase in cash provided by operating activities from the oil and gas and corporate segments in 2005 compared to 2004 was primarily due to increases in both production and natural gas and crude oil prices. Distributions we received from PVR increased to $28.3 million in 2006 from $21.2 million in 2005 and $17.3 million in 2004. We borrowed $142.0 million, net of repayments, in 2006 compared to $3.0 million in 2005 and $12.0 million in 2004 under our revolving credit facility. During 2006, 2005 and 2004, we used cash from operating and financing activities primarily for capital expenditures for oil and gas development and exploration activities and acquisitions of oil and gas properties.

Cash provided by operating activities in the PVR coal and PVR natural gas midstream segments increased $13.6 million, or 15%, to $107.3 million for the year ended December 31, 2006 from $93.7 million for 2005. The overall increase in cash provided by operating activities from the PVR coal and PVR midstream segments in 2006 compared to 2005 was primarily attributable to higher average gross coal royalties per ton and cash flows from the natural gas midstream business, which PVR acquired in March 2005, partially offset by increased cash outflows for derivative settlements. Cash provided by operating activities in the PVR coal and PVR midstream segments increased $38.9 million, or 71%, to $93.7 million for the year ended December 31, 2005 from $54.8 million for 2004. The overall increase in cash provided by operating activities in 2005 compared to 2004 was primarily attribuatable to higher average gross coal royalties per ton and cash flows from PVR's newly acquired natural gas midstream business. Included in 2006 financing activities for the PVR segments in the preceding table are $115.0 million in proceeds from PVR's issuance of common and Class B units. PVR issued common units in 2005 for net proceeds of $129.2 million. PVR made cash investments in 2006 primarily for coal reserve acquisitions, coal loadout facility construction and natural gas midstream acquisitions and gathering system expansions. PVR made cash investments in 2005 primarily for the acquisition of its natural gas midstream business and coal reserve acquisitions. PVR's cash investments in 2004 primarily related to its investment in the coal handling joint venture with Massey, which has been accounted for as an equity investment.

Capital expenditures, excluding noncash items, for each of the three years ended December 31, 2006 were as follows:

	Year ended December 31,		
	2006	2005	2004
		(in thousands)	
Oil and gas			
Proved property acquisitions	$ 72,724	$ —	$ —
Development drilling	175,257	107,744	77,053
Exploration drilling	41,923	18,562	16,411
Seismic	6,238	7,836	10,018
Lease acquisition and other (1)	27,795	30,297	13,046
Pipeline, gathering, facilities	14,547	5,138	18,669
Total	338,484	169,577	135,197
Coal			
Acquisitions (2)	15,103	5,657	783
Expansion capital expenditures	100	351	72
Other property and equipment expenditures	90,385	98,101	29,530
Total	105,588	104,109	30,385
Natural gas midstream			
Acquisitions, net of cash acquired	15,394	3,324	—
Expansion capital expenditures	9,414	4,264	—
Other property and equipment expenditures	39,434	206,811	—
Total	64,242	214,399	—
Other	3,682	350	176
Total capital expenditures	$511,996	$488,435	$165,758

(1) Amount in 2006 excludes deferred tax assets of $32.3 million and acquisition of net liabilities other than property or equipment of $29.1 million related to the Crow Creek Acquisition.

(2) Amount in 2006 excludes non-property and equipment assets acquired of $1.2 million. Amount in 2005 excludes noncash expenditure of $11.1 million to acquire coal reserves in Kentucky in the Wayland Acquisition in exchange for $10.4 million of equity issued in the form of PVR common units and $0.7 million of liabilities assumed. Amount in 2005 also excludes the noncash portion of the Green River Acquisition, in which PVR assumed $3.3 million of deferred income. Amount in 2004 excludes noncash expenditures of $1.1 million to acquire additional reserves on PVR's Northern Appalachia properties in exchange for equity issued in the form of PVR common and Class B units.

We are committed to expanding our oil and gas operations over the next several years through a combination of development, exploration and acquisition of new properties. We have a portfolio of assets which balances relatively low risk, moderate return development projects in Appalachia, Mississippi, east Texas and the Mid-Continent with relatively moderate risk, potentially higher return development projects and exploration prospects in south Texas and south Louisiana.

We have budgeted approximately $334 million for oil and gas segment capital expenditures in 2007. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on industry conditions and the availability of capital. We believe our cash flow from operations and sources of debt financing are sufficient to fund our 2007 planned oil and gas capital expenditures program.

During 2006, PVR made aggregate capital expenditures of $129.8 million for coal reserve acquisitions, coal loadout facility construction and natural gas midstream gathering systems. PVR's cash flows from operations and its revolving credit facility were used to fund coal and natural gas midstream capital expenditures, including three acquisitions, in 2006. During 2005, PVR made aggregate capital expenditures of $291.3 million for the Cantera Acquisition and four coal reserve acquisitions. To finance its 2005 acquisitions, PVR borrowed $137.2 million, net of repayments, received proceeds of $126.4 million from the sale of its common units in a public offering and received a $2.6 million contribution from its general partner, which was a wholly owned subsidiary of us and now is a wholly owned subsidiary of PVG. To finance its equity investment in the Massey coal handling joint venture in 2004, PVR borrowed $26.0 million, net of repayments.

We borrowed under our revolving credit facility, net of repayments, $142.0 million in 2006, $3.0 million in 2005 and $12.0 million in 2004. We also received cash distributions from PVR of $28.3 million in 2006, $21.2 million in 2005 and $17.3 million in 2004. Funds from both of these sources were primarily used for capital expenditures.

In February 2007, PVR paid a $0.40 per unit quarterly distribution for the three months ended December 31, 2006, or $1.60 per unit on an annualized basis. As a result of the PVR common units we directly own and the PVR common and Class B units, general partner interest and incentive distribution rights PVG owns, we expect PVR to pay cash distributions to us and PVG of approximately $42.4 million in 2007 compared to $28.3 million in 2006.

Long-Term Debt

Revolving Credit Facility. We have a revolving credit facility (or the Revolver) that is secured by a portion of our proved oil and gas reserves and matures in December 2010. Effective November 1, 2006, we amended the Revolver to increase the commitment from $200 million to $300 million and the borrowing base from $300 million to $400 million. We had $221.0 million outstanding under the Revolver as of December 31, 2006, giving us $79.0 of available borrowing capacity. The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) the London Inter Bank Offering Rate (or LIBOR) plus a Eurodollar margin ranging from 1.00% to 1.75%, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin of up to 0.50%. The weighted average interest rate on borrowings incurred during the year ended December 31, 2006 was approximately 6.4%. In 2006, we incurred commitment fees of $0.4 million on the unused portion of the Revolver. We capitalized $2.8 million of interest cost incurred in 2006. The Revolver allows for the issuance of up to $20 million of letters of credit, of which $0.7 million were issued as of December 31, 2006.

The financial covenants under the Revolver require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. The Revolver contains various other covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2006, we were in compliance with all of our covenants under the Revolver.

Line of Credit. We have a $10 million line of credit with a financial institution, which had no borrowings against it as of December 31, 2006. The line of credit is effective through June 2007 and is renewable annually. We increased the line of credit from $5 million to $10 million in June 2006. We have an option to elect either a fixed rate LIBOR loan, a floating rate LIBOR loan or a base rate (as determined by the financial institution) loan.

Revolver Interest Rate Swaps. Effective August 2, 2006, we entered into interest rate swap agreements (or the Revolver Swaps) to swap $50 million of outstanding borrowings under our Revolver from a variable rate to a weighted average fixed rate of 5.34% plus the applicable margin. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 1.25% in effect as of December 31, 2006, the total interest rate on the $50 million portion of Revolver borrowings covered by the Revolver Swaps was 5.47% at December 31, 2006.

PVR Revolving Credit Facility. As of December 31, 2006, PVR had $143.2 million outstanding under its unsecured $300 million revolving credit facility (or the PVR Revolver) that matures in December 2011. PVR used the proceeds from the sale of common units and Class B units to PVG in December 2006 to pay down $114.6 million of the PVR Revolver. The PVR Revolver is available to PVR for general purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2006. In 2006, PVR incurred commitment fees of $0.4 million on the unused portion of the PVR Revolver. PVR has a one-time option to expand the PVR Revolver by $150 million upon receipt by the credit facility's administrative agent of commitments from one or more lenders. The interest rate under the PVR Revolver fluctuates based on PVR's ratio of total indebtedness to EBITDA. Interest is payable at a base rate plus an applicable margin of up to 0.75% if PVR selects the base rate borrowing option under the Revolver or at a rate derived from LIBOR plus an applicable margin ranging from 0.75% to 1.75% if PVR selects the LIBOR-based borrowing option.

The financial covenants under the PVR Revolver require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's additional borrowing capacity under the PVR Revolver to approximately $257.0 million as of December 31, 2006. At the current $300 million limit on the PVR Revolver, and given the outstanding balance of $143.2 million, net of $1.6 million of letters of credit, PVR could borrow up to $155.2 million without exercising its one-time option to expand the PVR Revolver. In order to utilize the full extent of the $257.0 million borrowing capacity, PVR would need to exercise its one-time option to expand the PVR Revolver by $150 million. 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 distribution. In addition, the PVR Revolver contains various covenants that limit, among other things, PVR's ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2006, PVR was in compliance with all of its covenants under the PVR Revolver.

PVR Senior Unsecured Notes. As of December 31, 2006, PVR owed $74.8 million under its senior unsecured notes (or the PVR Notes). The PVR Notes bear interest at a fixed rate of 6.02% and mature in March 2013, with semi-annual principal and interest payments. The PVR Notes are equal in right of payment with all of PVR's other unsecured indebtedness, including the PVR Revolver. The PVR Notes require PVR to obtain an annual confirmation of its credit rating, with a 1.00% increase in the interest rate payable on the PVR Notes in the event its credit rating falls below investment grade. In March 2006, PVR's investment grade credit rating was confirmed by Dominion Bond Rating Services. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. As of December 31, 2006, PVR was in compliance with all of its covenants under the PVR Notes.

PVR Revolver Interest Rate Swaps. In September 2005, PVR entered into interest rate swap agreements (or the PVR Revolver Swaps) with notional amounts totaling $60 million to establish fixed rates on the LIBOR-based portion of the outstanding balance of the PVR Revolver until March 2010. PVR pays a weighted average fixed rate of 4.22% on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the PVR Revolver Swaps are recorded as interest expense. The PVR Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings in interest expense. After considering the applicable margin of 0.75% in effect as of December 31, 2006, the total interest rate on the $60 million portion of PVR Revolver borrowings covered by the PVR Revolver Swaps was 4.97% at December 31, 2006.

Future Capital Needs and Commitments

In the oil and gas segment, we expect to continue to execute a program dominated by relatively low risk, moderate return development drilling and, to a lesser extent, higher risk, higher return exploration drilling, supplemented periodically with acquisitions.

In 2007, we have budgeted oil and gas segment capital expenditures of approximately $334 million. These expenditures are expected to be funded primarily by operating cash flow, cash distributions received from PVG and from the Revolver as needed.

Part of PVR's strategy is to make acquisitions which increase cash available for distribution to its unitholders. Long-term cash requirements for asset acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under credit facilities and the issuance of additional equity and debt securities. PVR's ability to make these acquisitions in the future will depend in part on the availability of debt financing and on its ability to periodically use equity financing through the issuance of new common units, which will depend on various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

In 2007, PVR anticipates making capital expenditures, excluding acquisitions, of approximately $3.6 million to $4.7 million for coal services projects and other property and equipment and approximately $47 million to $52 million for natural gas midstream projects. PVR believes that it will continue to have adequate liquidity to fund future recurring operating and investing activities. Short-term cash requirements, such as operating expenses and quarterly distributions to its general partner and unitholders, are expected to be funded through operating cash flows. Funding sources for future PVR acquisitions are dependent on the size of any such acquisitions and are expected to be provided by a combination of cash flows provided by operating activities and borrowings, and potentially with the proceeds from the issuance of additional PVR equity.

We have budgeted additional capital expenditures of approximately $1 million to $2 million in 2007 for administrative purposes, including the implementation of a new accounting software system.

Contractual Obligations

Our contractual obligations as of December 31, 2006 are summarized in the following table:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	4-5 Years	Thereafter
			(in thousands)		
Revolving credit facility	$221,000	$ —	$ —	$221,000	$ —
PVR revolving credit facility	143,200	—	—	143,200	—
PVR senior unsecured notes	75,400	11,000	26,800	24,200	13,400
Rental commitments (1)	13,551	5,973	5,065	2,513	—
Oil and gas activities (2)	37,106	12,760	19,031	2,162	3,153
Total contractual obligations	$490,257	$29,733	$50,896	$393,075	$16,553

(1) Rental commitments primarily relate to equipment and building leases. Also included are PVR's rental commitments, which primarily relate to reserve-based properties which PVR subleases, or intends to sublease, to third parties. The obligation 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. See Item 1A, "Risk Factors." PVR believes that the future rental commitments cannot be reasonably estimated; however, based on current knowledge and historical trends, PVR believes that it will incur approximately $0.9 million in rental commitments in annually until the reserves have been exhausted.

(2) Commitments for oil and gas activities relate to firm transportation agreements and drilling contracts

Off-Balance Sheet Arrangements

At December 31, 2006, we did not have 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

The following table sets forth a summary of certain financial data for the periods indicated:

Selected Financial Data—Consolidated

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share data)		
Revenues	$753,929	$673,864	$228,425
Expenses	583,397	511,847	147,629
Operating income	$170,532	$162,017	$ 80,796
Net income	$ 75,909	$ 62,088	$ 33,355
Earnings per share, basic	$ 4.06	$ 3.35	$ 1.82
Earnings per share, diluted	$ 4.02	$ 3.31	$ 1.81
Cash flows provided by operating activities	$275,819	$231,407	$146,365

The increase in 2006 net income compared to 2005 net income was primarily attributable to a $7.1 million increase in operating income and a $34.4 million increase in derivative gains, partially offset by increased interest expense and the related net increase in income tax expense. Operating income in 2006 increased primarily due to increased operating income contributions from our ownership interest in PVR, which is reported under the PVR coal and PVR natural gas midstream segments.

The increase in 2005 net income compared to 2004 net income was primarily attributable to an $81.2 million increase in operating income, partially offset by increased interest expense on PVR's additional borrowings to fund acquisitions, a net loss on derivatives and the related net increase in income tax expense. Operating income in 2005 increased primarily due to increased operating income contributions from our oil and gas segment and our ownership interest in PVR, which included the contribution of a natural gas midstream business that PVR acquired in the first quarter of 2005.

The assets, liabilities and earnings of PVG are fully consolidated in our financial statements, with the public unitholders' interest (18% as of December 31, 2006) reflected as a minority interest. The assets, liabilities and earnings of PVR are fully consolidated in PVG's financial statements, with the public unitholders' interest (58%, after effect of incentive distribution rights, as of December 31, 2006) reflected as minority interest in PVG's financial statements.

Oil and Gas Segment

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

The following table sets forth a summary of certain financial and other data for our oil and gas segment and the percentage change for the periods indicated:

	Year Ended December 31,		%	Year Ended December 31,	
	2006	2005	Change	2006	2005
	(in thousands, except as noted)			(per Mcfe) (1)	
Production					
Natural gas (Mmcf)	28,968	25,550	13%		
Oil and condensate (thousand barrels)	382	302	26%		
Total production (Mmcfe)	31,260	27,362	14%		
Revenues					
Natural gas	$212,919	$212,427	0%	$ 7.35	$ 8.31
Oil and condensate	21,237	13,792	54%	55.59	45.67
Other income	1,800	600	200%		
Total revenues	235,956	226,819	4%	7.55	8.29
Expenses					
Operating	27,403	17,300	58%	0.88	0.63
Taxes other than income	11,810	13,188	(10)%	0.38	0.48
General and administrative	12,826	9,264	38%	0.41	0.34
Production costs	52,039	39,752	31%	1.66	1.45
Exploration	34,330	40,917	(16)%	1.10	1.50
Impairment of oil and gas properties	8,517	4,785	78%	0.27	0.17
Depreciation, depletion and amortization	56,237	45,885	23%	1.80	1.68
Total expenses	151,123	131,339	15%	4.83	4.80
Operating income	$ 84,833	$ 95,480	(11)%	$ 2.71	$ 3.49

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

Production. Total production increased 14% in 2006 primarily due to new production from increased drilling, including the Cotton Valley play in east Texas, the Selma Chalk development play in Mississippi and the success of our Fannett exploration prospect in south Texas drilled in the second quarter of 2005. The Mid-Continent region, acquired through the Crow Creek Acquisition in June 2006, added 1.2 Bcfe to 2006 production. Production increases were partially offset by normal field declines and water disposal issues, which resulted in shutting in or temporarily delaying production from some of our horizontal CBM wells in Appalachia.

Revenues. Approximately 93% of production in 2006 and 2005 was natural gas. Increased natural gas production resulted in an approximately $28.4 million increase in natural gas revenues, almost fully offset by an approximately $27.9 million decrease in natural gas revenues resulting from decreased realized prices for natural gas. The average realized price received for natural gas during 2006 was $7.35 per Mcf compared with $8.31 per Mcf in 2005, a 12% decrease. Increased oil and condensate production accounted for approximately $3.7 million, or 49%, of the increase in oil and condensate revenues. Increased realized prices for oil and condensate accounted for approximately $3.8 million, or 51%, of the increase in oil and condensate revenues. The average realized oil price received was $55.59 per barrel in 2006, up 22% from $45.67 per barrel in 2005.

Natural gas, oil and condensate revenues are derived from the sale of our oil and gas production, which is net of the effects of the settlement of derivative contracts that follow hedge accounting. Settlement of our derivative contracts that do not follow hedge accounting has no effect on our reported revenues. Our revenues may vary significantly from period to period as a result of changes in commodity prices or production volumes.

Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

The following table shows a summary of the effects of derivative activities on revenues and realized prices for the years ended December 31, 2006 and 2005:

	Year Ended December 31,			
	2006	2005	2006	2005
	(in thousands)		(per Mcf)	
Natural gas revenue, as reported	$212,919	$212,427	$ 7.35	$ 8.31
Derivatives (gains) losses included in natural gas revenues	(448)	14,049	(0.02)	0.55
Natural gas revenue before impact of derivatives	212,471	226,476	7.33	8.86
Cash settlements on natural gas derivatives	10,711	(14,049)	0.37	(0.55)
Natural gas revenues, adjusted for derivatives	$223,182	$212,427	$ 7.70	$ 8.31
			(per Bbl)	
Crude oil revenue, as reported	$ 21,237	$ 13,792	$55.59	$45.67
Derivatives (gains) losses included in oil and condensate revenues	457	857	1.20	2.84
Oil and condensate revenue before impact of derivatives	21,694	14,649	56.79	48.51
Cash settlements on crude oil derivatives	(200)	(857)	(0.52)	(2.84)
Oil and condensate revenues, adjusted for derivatives	$ 21,494	$ 13,792	$56.27	$45.67

Expenses. Operating costs and expenses in 2006 increased due to increases in operating expenses, general and administrative expenses, impairment of oil and gas properties and depreciation, depletion and amortization (or DD&A) expenses. These increases were offset by decreases in taxes other than income and exploration expense.

Operating expenses increased primarily due to additional compressor rentals at fields with increased production, downhole maintenance charges associated with horizontal CBM wells in Appalachia and Selma Chalk wells in Mississippi, increased surface repair costs and increased gathering fees related to horizontal CBM and Cotton Valley wells.

Taxes other than income decreased due to a severance tax refund related to production in the Cotton Valley play. This decrease was offset by higher severance taxes as a result of increased production.

General and administrative expenses increased primarily due to increased payroll costs as a result of wage increases and new personnel and consulting fees.

Exploration expenses for the years ended December 31, 2006 and 2005 consisted of the following:

	2006	2005
	(in thousands)	
Dry hole costs	$15,178	$11,379
Seismic	6,237	7,739
Unproved leasehold	9,410	17,761
Other	3,505	4,038
Total	$34,330	$40,917

Exploration expenses decreased primarily due to unproved leasehold and dry hole costs related to an exploratory well in south Texas that was determined to be unsuccessful in the second quarter of 2005. There were offsetting increases in dry hole costs due to the write-off of exploratory wells and in unproved leasehold due to the amortization of unproved property pools in 2006. The timing of seismic data purchases in 2006 and 2005 caused seismic expenses to decrease in 2006 compared to 2005.

Impairment charges in 2006 related to changes in estimates of reserve bases of certain fields in Louisiana, Texas and West Virginia. Impairment charges in 2005 related to changes in estimates of reserve bases of certain fields in Texas.

Oil and gas DD&A expenses increased due to the 14% increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.68 per Mcfe for 2005 to $1.80 per Mcfe for 2006 as a result of a greater percentage of production coming from relatively higher cost horizontal CBM and Cotton Valley wells and general price inflation for equipment, services and tubulars used for drilling and development.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

The following table sets forth a summary of certain financial and other data for our oil and gas segment and the percentage change for the periods indicated:

	2005	2004	% Change	2005	2004
	(in thousands, except as noted)			(per Mcfe)	
Production					
Natural gas (Mmcf)	25,550	22,079	16%		
Oil and condensate (thousand barrels)	302	396	(24)%		
Total production (Mmcfe)	27,362	24,555	11%		
Revenues					
Natural gas	$212,427	$138,422	53%	$ 8.31	$ 6.27
Oil and condensate	13,792	13,364	3%	45.67	33.75
Other income	600	(114)	(626)%		
Total revenues	226,819	151,672	50%	8.29	6.18
Expenses					
Operating	17,300	13,949	24%	0.63	0.57
Taxes other than income	13,188	9,325	41%	0.48	0.38
General and administrative	9,264	8,336	11%	0.34	0.34
Production costs	39,752	31,610	26%	1.45	1.29
Exploration	40,917	26,058	57%	1.50	1.07
Impairment of oil and gas properties	4,785	655	631%	0.17	0.03
Loss on assets held for sale	—	7,541	(100)%	—	0.31
Depreciation, depletion and amortization	45,885	35,886	28%	1.68	1.47
Total expenses	131,339	101,750	29%	4.80	4.17
Operating income	$ 95,480	$ 49,922	91%	$ 3.49	$ 2.03

* Natural gas revenues are shown per Mcf, oil and condensate revenues are shown per Bbl, and all other amounts are shown per Mcfe.

Production. Total production increased 11% in 2005 primarily due to new production from increased drilling, including the HCBM play in Appalachia, the Selma Chalk development play in Mississippi and the Cotton Valley play in east Texas and north Louisiana. Production increases were partially offset by the first quarter 2005 sale of oil and gas properties in west Texas, production shut-ins along the Gulf Coast as a result of hurricanes Katrina and Rita and normal field declines.

Revenues. Approximately 93% and 90% of production in 2005 and 2004 was natural gas. Increased natural gas production accounted for approximately $21.8 million, or 29%, of the increase in natural gas revenues. Increased realized prices for natural gas accounted for approximately $52.2 million, or 71%, of the increase in natural gas revenues. The average realized price received for natural gas during 2005 was $8.31 per Mcf compared with $6.27 per Mcf in 2004, a 33% increase. The average realized oil price received was $45.67 per barrel in 2005, up 35% from $33.75 per barrel in 2004. This price increase for crude oil was offset by a decline in oil production compared to 2004 due to the January 2005 sale of oil and gas properties in West Texas, production shut-ins along the Gulf Coast as a result of hurricanes Katrina and Rita and normal field declines.

Due to the volatility of crude oil and natural gas prices, in 2005 and 2004, we hedged the price received for certain sales volumes through the use of swaps and costless collars in accordance with our hedging policy. Gains and losses from hedging activities are included in revenues when the hedged production occurs. In 2005, approximately 42% of our natural gas was hedged using costless collars at an average floor price of $5.61 per MMbtu and an average ceiling price of $8.10 per MMbtu. We also hedged approximately 31% of our crude oil production using a fixed price swap in January 2005 and a costless collar beginning in March 2005 and continuing for the remainder of the year. The swap price was $30.59 per barrel, and the costless collar had a floor price of $42.00 per barrel and a ceiling price of $47.75 per barrel. We recognized a loss on settled derivative contracts accounted for as cash flow hedges of $14.9 million in 2005, compared with a loss of $5.9 million in 2004.

Expenses. Operating costs and expenses in 2005 increased primarily due to increases in operating expenses, exploration expenses, taxes other than income, general and administrative expenses, impairments and DD&A expenses. These increases were partially offset by the absence in 2005 of a loss on assets held for sale.

Operating expenses increased primarily due to additional compressor rentals at fields with increased production, downhole maintenance charges associated with HCBM wells in Appalachia and Selma Chalk wells in Mississippi and increased water disposal costs.

Exploration expenses for the years ended December 31, 2005 and 2004 consisted of the following:

	2005	2004
	(in thousands)	
Dry hole costs	$11,379	$10,284
Seismic	7,739	9,225
Unproved leasehold	17,761	5,726
Other	4,038	823
Total	$40,917	$26,058

Exploration expenses increased primarily due to higher unproved leasehold write-offs and dry hole costs for an unsuccessful exploratory well in south Texas. The balance of the increase in exploration expenses was primarily due to unproved leasehold write-offs relating to expired lease options and increased delay rentals on certain leaseholds in south Louisiana.

Taxes other than income increased due to higher severance taxes as a result of increased production and higher gas prices. General and administrative expenses increased primarily due to increased payroll costs as a result of wage increases and new personnel. Impairment charges in 2005 related to changes in estimates of reserve bases of certain fields in Texas.

Oil and gas DD&A expenses increased due to the 12% increase in equivalent production and as a result of higher average depletion rates. The average depletion rate increased from $1.47 per Mcfe in 2004 to $1.67 per Mcfe in 2005 as a result of a greater percentage of production coming from relatively higher cost horizontal CBM and Cotton Valley wells and general price inflation for equipment, services and tubulars used for drilling and development, combined with depreciation on new pipeline infrastructure placed in service during the fourth quarter of 2004.

A loss of $7.5 million was recognized in 2004 for the write-down to realizable value of a group of non-core properties in west Texas that were sold in January 2005.

PVR Coal Segment

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

The following table sets forth a summary of certain financial and other data for PVR's coal segment and the percentage change for the periods indicated:

	Year Ended December 31, 2006	Year Ended December 31, 2005	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$ 98,163	$82,725	19%
Coal services	5,864	5,230	12%
Other	8,954	7,800	15%
Total revenues	112,981	95,755	18%
Expenses			
Operating	8,600	5,755	49%
Taxes other than income	934	1,129	(17)%
General and administrative	9,604	9,237	4%
Depreciation, depletion and amortization	20,399	17,890	14%
Total expenses	39,537	34,011	16%
Operating income	$ 73,444	$61,744	19%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	32,778	30,227	8%
Average royalty per ton ($/ton)	$ 2.99	$ 2.74	9%

Revenues. Coal royalty revenues increased to $98.2 million in 2006 from $82.7 million in 2005, or 19%, due to a higher average royalty per ton and increased production. The average royalty per ton increased to $2.99 in 2006 from $2.74 in 2005. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced under certain price-sensitive leases and, for most of 2006, stronger market conditions for coal resulting in higher prices. Coal production by PVR's lessees increased primarily due to production on PVR's Illinois Basin property, which PVR acquired in the third quarter of 2005, and production on PVR's Central Appalachian property due to the Huff Creek Acquisition in May 2006.

Coal services revenues increased primarily due to increased equity earnings from PVR's coal handling joint venture and increased revenues from coal handling facilities that processed higher volumes. PVR's newly constructed facility on PVR's Central Appalachian property began operations in October 2006 and contributed $0.2 million to coal services revenues in 2006.

Other revenues increased primarily due to the following factors. In 2006 and 2005, PVR earned $1.7 million and $0.8 million in revenues for the management of certain coal properties. Forfeiture income increased $1.9 million in 2006 from $0.8 million in 2005 due to timing of lease terms. In 2006 and 2005, PVR recognized $0.8 million and $0.4 million in railcar rental income related to railcars it purchased in June 2005. In 2006 and 2005, PVR recognized $1.9 million and $1.3 million of wheelage fees, primarily as a result of the Alloy Acquisition. These increases were partially offset by a decrease from $1.4 million in 2005 to $1.0 million in 2006 in royalty income from oil and natural gas royalty interest acquired in the March 2005 Coal River Acquisition. Further offsetting the increases was $1.5 million PVR received in 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents.

Expenses. Operating expenses increased to $8.6 million in 2006 from $5.8 million in 2005, or 49%, due to production on PVR's subleased Central Appalachian property acquired in the Huff Creek Acquisition in May 2006. This increase was partially offset by a decrease in production from other subleased properties primarily resulting from the movement of longwall mining operations at one of these properties. Fluctuations in production on subleased properties have a direct impact on royalty expense. General and administrative expenses increased due to absorbing operations related to PVR's 2005 and 2006 acquisitions, increased professional fees and payroll costs relating to evaluating acquisition opportunities and increased reimbursement to PVR's general partner for shared corporate overhead costs. DD&A expense increased due to the increase in production and a higher depletion rate on recently acquired reserves.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

The following table sets forth a summary of certain financial and other data for PVR's coal segment and the percentage change for the periods indicated:

	Year Ended December 31, 2005	Year Ended December 31, 2004	% Change
	(in thousands, except as noted)		
Financial Highlights			
Revenues			
Coal royalties	$82,725	$69,643	19%
Coal services	5,230	3,787	38%
Other	7,800	2,200	255%
Total revenues	95,755	75,630	27%
Expenses			
Operating	5,755	7,224	(20)%
Taxes other than income	1,129	948	19%
General and administrative	9,237	8,307	11%
Depreciation, depletion and amortization	17,890	18,632	(4)%
Total expenses	34,011	35,111	(3)%
Operating income	$61,744	$40,519	52%
Operating Statistics			
Royalty coal tons produced by lessees (tons in millions)	30,227	31,181	(3)%
Average royalty per ton ($/ton)	$ 2.74	$ 2.23	23%

Revenues. Coal royalty revenues increased to $82.7 million in 2005 from $69.6 million in 2004, or 19%, due to a higher average royalty per ton despite a 3% decrease in production. The average royalty per ton increased to $2.74 in 2005 from $2.23 in 2004. The increase in the average royalty per ton was primarily due to a greater percentage of coal being produced from certain price-sensitive leases and stronger market conditions for coal resulting in higher prices. Coal production by PVR's lessees decreased primarily due to a loss of production resulting from one lessee's longwall mining operation moving off of PVR's property and onto an adjacent third party property in the first quarter of 2005. Production also decreased due to the inability of one lessee's customer to receive shipments because of an operating problem at the customer's power generation facility. These decreases were partially offset by production from property PVR acquired July 2005 in the Illinois Basin.

Coal services revenues increased 38% to $5.2 million in 2005 from $3.8 million in 2004. The increase in coal services revenues primarily related to increased equity earnings from the coal handling joint venture in which PVR acquired a 50% interest in July 2004. Increased revenues from two coal handling facilities that began operating in July 2003 and February 2004 also contributed to the increase.

Other revenues increased 255% to $7.8 million in 2005 from $2.2 million in 2004 primarily due to the following factors. PVR received $1.3 million of additional wheelage fees primarily as a result of the Alloy Acquisition in April 2005. PVR also received $1.5 million during the second quarter of 2005 from the sale of a bankruptcy claim filed against a former lessee in 2004 for lost future rents. PVR received $1.4 million of royalty income in 2005 from the oil and natural gas royalty interests acquired in the March 2005 Coal River Acquisition, $0.8 million in fees for the management of certain coal properties and $0.4 million of rental income from railcars purchased in the second quarter of 2005.

Expenses. Operating expenses decreased to $5.8 million in 2005 from $7.2 million in 2004, or 20%, due to a decrease in production from subleased properties, partially offset by new wheelage expenses incurred as a result of the April 2005 Alloy Acquisition. Production from subleased properties decreased by 32% to 4.6 million tons in 2005 from 6.8 million tons in 2004. Fluctuations in production on subleased properties have a direct impact on royalty expense. General and administrative expenses increased primarily due to increased accounting and tax related fees and increased payroll costs due to new personnel and wage increases. The decrease in DD&A expense is consistent with the decrease in production.

PVR Natural Gas Midstream Segment

PVR began operating in its natural gas midstream segment on March 3, 2005 with the acquisition of Cantera's natural gas midstream business. The results of operations of the natural gas midstream segment since that date are discussed below.

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

	Year Ended December 31, 2006	Year Ended December 31, 2005 (1)	% Change
	(in thousands)		
Financial Highlights			
Revenues			
Residue gas	$259,764	$233,208	11%
Natural gas liquids	130,675	106,453	23%
Condensate	9,989	7,322	36%
Gathering and transportation fees	2,287	1,674	37%
Total natural gas midstream revenues	402,715	348,657	16%
Marketing revenue, net	2,195	1,936	13%
Total revenues	404,910	350,593	15%
Expenses			
Cost of gas purchased	334,594	303,912	10%
Operating	11,403	9,347	22%
Taxes other than income	1,420	1,268	12%
General and administrative	11,023	6,982	58%
Depreciation and amortization	17,094	12,738	34%
Total operating expenses	375,534	334,247	12%
Operating income	$ 29,376	$ 16,346	80%
Operating Statistics			
Inlet volumes (MMcf)	55,991	38,875	44%
Midstream processing margin (2)	$ 68,121	$ 44,745	52%

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.

(2) Midstream processing margin consists of total natural gas midstream revenues minus the cost of gas purchased.

The financial and other data presented in the table above for 2005 include ten months of operations of PVR's midstream business. One of the primary reasons for the significant differences in PVR's results of operations for 2006 as compared to 2005 is that the 2006 data includes 12 full months of operations of the midstream business.

Revenues. Revenues included residue gas sold from processing plants after NGLs were removed, NGLs sold after being removed from inlet volumes received, condensate collected and sold, gathering and other fees primarily from natural gas volumes connected to PVR's gas processing plants and the purchase and resale of natural gas not connected to its gathering systems and processing plants. The increase in natural gas midstream revenues was primarily a result of an additional two months of operations in 2006 and higher average NGL and condensate prices in 2006.

Expenses. Operating costs and expenses primarily consisted of the cost of gas purchased and also included operating expenses, taxes other than income, general and administrative expenses and depreciation and amortization. Expenses generally increased due to an additional months of activity in 2006. The following paragraphs describe other factors contributing to the change in expenses.

Cost of gas purchased consisted of amounts payable to third-party producers for natural gas purchased under percentage of proceeds and keep-whole contracts. The increase in the cost of gas purchased was primarily due to overall volume of natural gas purchased in 2006. Included in cost of gas purchased for 2006 was a $4.6 million non-cash charge to reserve for amounts related to balances assumed as part of the Cantera Acquisition. The following table shows a summary of the effects of derivative activities on midstream processing margin:

	Year Ended December 31,	
	2006	2005
	(in thousands)	
Midstream processing margin, as reported	$ 68,121	$44,745
Derivatives losses included in midstream processing margin	1,953	(988)
Midstream processing margin before impact of derivatives	70,074	43,757
Cash settlements on derivatives	(19,436)	(4,752)
Midstream processing margin, adjusted for derivatives	$ 50,638	$39,005

Operating expenses increased due to rent and maintenance costs associated with additional compressors. General and administrative expenses increased primarily due to additional personnel added to support the business and recent acquisitions, and increased reimbursement to PVR's general partner for shared corporate overhead costs from $0.8 million in 2005 to $2.4 million in 2006. Depreciation and amortization expense increased due to depreciation on the pipeline acquired in the June 2006 Transwestern Acquisition and recent gathering system expansions.

Corporate and Other

Corporate and other results primarily consist of oversight and administrative functions.

Expenses. Corporate operating expenses increased by $4.6 million from $12.3 million in 2005 to $16.9 million in 2006. The increase was primarily related to increased general and administrative expenses which included higher payroll costs as a result of wage increases, new personnel and the recognition of $1.4 million for stock option expense upon adoption of SFAS No. 123(R), *Share-Based Payment,* on January 1, 2006. Corporate operating expenses increased by $1.5 million from $10.8 million in 2004 to $12.3 million in 2005. The increase was primarily related to increased general and administrative expenses which included higher payroll costs as a result of wage increases and new personnel and changes in director compensation.

Interest Expense. Interest expense increased by $9.5 million from $15.3 million in 2005 to $24.8 million in 2006. Interest expense increased by $7.6 million from $7.7 million in 2004 to $15.3 million in 2005. The increase in both periods was primarily due to interest incurred on additional borrowings under the Revolver and the PVR Revolver to finance 2005 and 2006 acquisitions and a general increase in interest rates. We capitalized interest costs amounting to $3.2 million, $3.5 million and $2.0 million in 2006, 2005 and 2004 because the borrowings funded the preparation of unproved properties for their intended use.

Derivatives. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

Net derivative gains were $19.5 million for 2006 and included a $19.0 million unrealized gain for mark-to-market adjustments and a $0.5 million unrealized gain for changes in hedge effectiveness. The unrealized gain due to changes in fair market value was associated with derivative contracts that we no longer accounted for using hedge accounting and represented changes in the fair value of our open contracts during the period. The unrealized gain for changes in hedge effectiveness was associated with hedging contracts that we accounted for using hedge accounting under SFAS No. 133. Derivative losses of $14.9 million for 2005 included a $13.9 million unrealized loss for mark-to-market adjustments on certain PVR derivative agreements, a $0.7 million unrealized loss for mark-to-market adjustments on a natural gas basis swap for which we elected not to use hedge accounting and a $0.3 million net unrealized loss for changes in effectiveness of open commodity price hedges related to the natural gas midstream segment and the oil and gas segment. The $13.9 million unrealized loss primarily represented the change in market value of derivative agreements between the time PVR entered into the agreements in January 2005 and the time the derivative agreements qualified for hedge accounting after closing the acquisition of the natural gas midstream business in March 2005.

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.

The operations of PVR's coal lessees and natural gas midstream segment 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 for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified PVR against any and all future environmental liabilities. PVR regularly visits coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of PVR's coal lessees and natural gas midstream segment will comply with existing regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2006 and 2005, PVR's environmental liabilities included $1.6 million and $2.5 million, which represents PVR's best estimate of the liabilities as of those dates related to the coal and natural gas midstream businesses. PVR has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when the reclamation area will meet regulatory standards, a change in this estimate could occur in the future.

See Item 1, "Business—Government Regulation and Environmental Matters" for a more detailed discussion of environmental laws and regulations affecting our business.

Recent Accounting Pronouncements

See Note 3 in the Notes to Consolidated Financial Statements for a description of recent accounting pronouncements.

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. 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 risks set forth in Item 1A, "Risk Factors."

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC. 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.

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 are exposed are NGL, crude oil, natural gas and coal price risks and interest rate risk.

We are also indirectly exposed to the credit risk of our and PVR's customers and PVR's lessees. If our customers or PVR's lessees become financially insolvent, they may not be able to continue operating or meet their payment obligations.

Price Risk Management

Our price risk management program permits the utilization of derivative financial instruments (such as futures, forwards, option contracts 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. Prior to May 1, 2006, these financial instruments were historically designated as cash flow hedges and accounted for in accordance with SFAS No. 133. The derivative financial instruments are placed with major financial institutions that we believe are of minimum credit risk. The fair value of our price risk management assets is significantly affected by fluctuations in the prices of natural gas, NGLs and crude oil.

For the year ended December 31, 2006, we reported a net $19.0 million derivative gain for mark-to-market adjustments on certain derivatives that no longer qualified for hedge accounting effective January 1, 2006. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. We will recognize hedging losses of $0.3 million in 2007 related to settlements of the oil and gas segment's hedged transactions for which we deferred net losses in accumulated other comprehensive income through April 30, 2006. PVR will recognize hedging losses of $4.6 million in 2007 and $5.5 million in 2008 related to settlements of the PVR natural gas midstream segment's hedged transactions for which PVR deferred net losses in accumulated other comprehensive income through April 30, 2006. The discontinuation of hedge accounting will have no impact on our reported cash flows, although future results of operations will be affected by the potential volatility mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices. See the discussion and tables in Note 10 in the Notes to Consolidated Financial Statements for a description of our derivative program. The following tables list our open mark-to-market derivative agreements and their fair values as of December 31, 2006:

Oil and Gas Segment Derivatives

	Average Volume Per Day	Weighted Average Price			Estimated Fair Value (in thousands)
		Additional Put Option	Floor	Ceiling	
	(in Mmbtus)		(per Mmbtu)		
Natural Gas Costless Collars					
First Quarter 2007	30,000		$ 8.50	$16.35	$ 6,208
Second Quarter 2007	15,000		$ 7.33	$12.93	1,576
Third Quarter 2007	15,000		$ 7.33	$12.93	1,547
Fourth Quarter 2007	11,685		$ 8.28	$15.78	1,525
First Quarter 2008	10,000		$ 9.00	$17.95	1,312
	(in Mmbtus)		(per Mmbtu)		
Natural Gas Three-way Collars					
First Quarter 2007	13,000	$5.00	$ 7.62	$10.15	1,712
Second Quarter 2007	33,000	$5.00	$ 7.55	$ 9.05	2,537
Third Quarter 2007	33,000	$5.00	$ 7.55	$ 9.05	1,667
Fourth Quarter 2007	19,379	$5.17	$ 7.74	$10.43	614
First Quarter 2008	12,500	$5.40	$ 8.00	$12.15	125
Second Quarter 2008	2,500	$5.00	$ 8.00	$10.75	201
Third Quarter 2008	2,500	$5.00	$ 8.00	$10.75	173
Fourth Quarter 2008	2,500	$5.00	$ 8.00	$10.75	79
	(in Mmbtus)		(per Mmbtu)		
Natural Gas Swaps					
First Quarter 2007	5,000		$ 7.12		407
	(in barrels)		(per barrel)		
Crude Oil Costless Collars					
First Quarter 2007	200		$60.00	$72.20	20
Second Quarter 2007	200		$60.00	$72.20	8
Third Quarter 2007	200		$60.00	$72.20	(7)
Fourth Quarter 2007	200		$60.00	$72.20	(20)
Oil and gas segment commodity derivatives—net asset					$19,684

PVR Natural Gas Midstream Segment Derivatives

	Average Volume Per Day	Weighted Average Price	Estimated Fair Value (in thousands)
	(in gallons)	(per gallon)	
Ethane Swaps			
First Quarter 2007 through Fourth Quarter 2007	34,440	$0.5050	(1,277)
First Quarter 2008 through Fourth Quarter 2008	34,440	$0.4700	(1,377)
	(in gallons)	(per gallon)	
Propane Swaps			
First Quarter 2007 through Fourth Quarter 2007	26,040	$0.7550	(1,543)
First Quarter 2008 through Fourth Quarter 2008	26,040	$0.7175	(1,795)
	(in barrels)	(per barrel)	
Crude Oil Swaps			
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(2,815)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(3,446)
	(in MMbtu)	(per MMbtu)	
Natural Gas Swaps			
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	(11)
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	1,479
December 2006 Settlements			(1,350)
Natural gas midstream segment commodity derivatives—net liability			$(12,135)

Taking into account the derivative positions described above, for every $1.00 per MMbtu decrease or increase in natural gas prices, natural gas midstream gross processing margin and operating income would increase or decrease by approximately $8.1 million. Taking into account the derivative positions described above, for every $5.00 per barrel increase or decrease in the oil prices, natural gas midstream gross processing margin and operating income would increase or decrease by approximately $10.0 million.

Interest Rate Risk

As of December 31, 2006, we had $221.0 million of outstanding indebtedness under the Revolver, which carries a variable interest rate throughout its term. We executed interest rate derivative transactions in August 2006 to effectively convert the interest rate on $50 million of the amount outstanding under the Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 5.34% plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding under the Revolver (net of amounts fixed through hedging transactions) at December 31, 2006 would cost approximately $1.7 million in additional interest expense.

As of December 31, 2006, PVR had $143.2 million of outstanding indebtedness under the PVR Revolver, which carries a variable interest rate throughout its term. PVR executed interest rate derivative transactions in September 2005 to effectively convert the interest rate on $60 million of the amount outstanding under the PVR Revolver from a LIBOR-based floating rate to a weighted average fixed rate of 4.22% plus the applicable margin. The interest rate swaps are accounted for as cash flow hedges in accordance with SFAS No. 133. A 1% increase in short-term interest rates on the floating rate debt outstanding under the PVR Revolver (net of amounts fixed through hedging transactions) at December, 2006 would cost approximately $0.8 million in additional interest expense.

Item 8 *Financial Statements and Supplementary Data*

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL SECTION

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, a Virginia corporation, and subsidiaries as of December 31, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Penn Virginia Corporation changed its method of accounting for share-based payments. As also discussed in Note 2 to the consolidated financial statements, effective December 31, 2006, the Company changed its method of accounting for postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Penn Virginia Corporation's internal control over financial reporting as of December 31, 2006, 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 February 28, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Item 9A(b)), that Penn Virginia Corporation, a Virginia corporation, maintained effective internal control over financial reporting as of December 31, 2006, based on the 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, management's assessment that Penn Virginia Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by COSO. Also, in our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by COSO.

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 as of December 31, 2006 and 2005, and the related consolidated statements of income, stockholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 28, 2007

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

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

	Year Ended December 31,		
	2006	2005	2004
Revenues			
Natural gas	$212,919	$212,427	$138,422
Oil and condensate	21,237	13,792	13,364
Natural gas midstream	402,715	348,657	—
Coal royalties	98,163	82,725	69,643
Other	18,895	16,263	6,996
Total revenues	753,929	673,864	228,425
Expenses			
Cost of midstream gas purchased	334,594	303,912	—
Operating	47,406	32,685	21,773
Exploration	34,330	40,917	26,058
Taxes other than income	14,767	16,005	10,480
General and administrative	49,566	36,606	26,170
Impairment of oil and gas properties	8,517	4,785	655
Loss on assets held for sale	—	—	7,541
Depreciation, depletion and amortization	94,217	76,937	54,952
Total expenses	583,397	511,847	147,629
Operating income	170,532	162,017	80,796
Other income (expense)			
Interest expense	(24,832)	(15,318)	(7,672)
Other	3,718	1,332	1,101
Derivatives	19,497	(14,885)	—
Income before minority interest and income taxes	168,915	133,146	74,225
Minority interest	43,018	30,389	19,023
Income tax expense	49,988	40,669	21,847
Net income	$ 75,909	$ 62,088	$ 33,355
Net income per share, basic	$ 4.06	$ 3.35	$ 1.82
Net income per share, diluted	$ 4.02	$ 3.31	$ 1.81
Weighted average shares outstanding, basic	18,681	18,546	18,306
Weighted average shares outstanding, diluted	18,866	18,732	18,467

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2006	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ 20,338	$ 25,913
Accounts receivable	138,880	133,086
Derivative assets	18,244	11,551
Other	14,921	7,635
Total current assets	192,383	178,185
Property and equipment		
Oil and gas properties (successful efforts method)	1,045,182	717,423
Other property and equipment	671,169	538,035
	1,716,351	1,255,458
Accumulated depreciation, depletion and amortization	(357,968)	(272,239)
Net property and equipment	1,358,383	983,219
Equity investments	25,355	26,672
Goodwill	7,718	7,718
Intangibles, net	33,045	38,051
Derivative assets	4,344	8,917
Other assets	11,921	8,784
Total assets	$1,633,149	$1,251,546
Liabilities and Shareholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 10,832	$ 8,108
Accounts payable and accrued liabilities	154,709	114,678
Derivative liabilities	7,149	29,387
Income taxes payable	—	2,355
Total current liabilities	172,690	154,528
Other liabilities	26,003	24,448
Derivative liabilities	7,065	11,706
Deferred income taxes	178,380	111,186
Long-term debt of the Company	221,000	79,000
Long-term debt of subsidiary	207,214	246,846
Minority interests of subsidiaries	438,372	313,524
Shareholders' equity		
Preferred stock of $100 par value—100,000 shares authorized; none issued	—	—
Common stock of $0.01 par value—32,000,000 shares authorized; 18,780,632 and 18,624,002 shares issued and outstanding at December 31, 2006, and December 31, 2005	188	186
Paid-in capital	100,559	98,541
Retained earnings	289,967	222,456
Deferred compensation obligation	1,314	580
Accumulated other comprehensive income	(7,954)	(7,816)
Treasury stock—35,449 and 23,644 shares common stock, at cost, on December 31, 2006, and December 31, 2005	(1,649)	(832)
Unearned compensation	—	(2,807)
Total shareholders' equity	382,425	310,308
Total liabilities and shareholders' equity	$1,633,149	$1,251,546

See accompanying notes to consolidated financial statements.

PENN 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	Treasury Stock	Unearned Compensation and ESOP	Total Shareholders' Equity	Comprehensive Income (Loss)
Balance as of December 31, 2003	18,105	$ 56,576	$ 14,497	$143,619	$ —	$(2,250)	$ —	$ (794)	$211,648	$27,933
Dividends paid ($0.45 per share)	—	—	—	(8,248)	—	—	—	—	(8,248)	
Recognition of gain on conversion of subordinated PVR units to common	—	—	6,393	—	—	—	—	—	6,393	
Stock issue as compensation	7	—	239	—	—	—	—	—	239	
PVR units issued as compensation, net	—	—	440	—	—	—	—	(139)	301	
Vesting of restricted units	—	—	(354)	—	—	—	—	—	(354)	
Exercise of stock options	364	4	7,814	—	—	—	—	—	7,818	
Allocation of ESOP shares	—	—	119	—	—	—	—	59	178	
Change in par value	—	(56,395)	56,395	—	—	—	—	—	—	
Net income	—	—	—	33,355	—	—	—	—	33,355	$33,355
Other comprehensive gain, net of tax	—	—	—	—	—	1,530	—	—	1,530	1,530
Balance at December 31, 2004	18,476	185	85,543	168,726	—	(720)	—	(874)	252,860	$34,885
Dividends paid ($0.45 per share)	—	—	—	(8,358)	—	—	—	—	(8,358)	
Recognition of gain on conversion of subordinated PVR units to common	—	—	6,393	—	—	—	—	—	6,393	
Stock issued as compensation	29	—	1,656	—	—	—	—	(1,507)	149	
PVR units issued as compensation, net	—	—	1,123	—	—	—	—	(426)	697	
Vesting of restricted units	—	—	(315)	—	—	—	—	—	(315)	
Exercise of stock options	119	1	3,561	—	—	—	—	—	3,562	
Deferred compensation	—	—	580	—	580	—	(832)	—	328	
Net income	—	—	—	62,088	—	—	—	—	62,088	$62,088
Other comprehensive loss, net of tax	—	—	—	—	—	(7,096)	—	—	(7,096)	(7,096)
Balance at December 31, 2005	18,624	186	98,541	222,456	580	(7,816)	(832)	(2,807)	310,308	$54,992
Adoption of SFAS No. 123(R) (See Note 18)	—	—	(2,807)	—	—	—	—	2,807	—	
Dividends paid ($0.45 per share)	—	—	—	(8,398)	—	—	—	—	(8,398)	
Gain on sale of PVR and PVG securities	—	—	(3,560)	—	—	—	—	—	(3,560)	
Stock issued as compensation	6	—	691	—	—	—	—	—	691	
PVR units issued as compensation, net	—	—	1,229	—	—	—	—	—	1,229	
Vesting of restricted units	—	—	(1,056)	—	—	—	—	—	(1,056)	
Exercise of stock options	151	2	5,860	—	—	—	—	—	5,862	
Recognition of stock option expense	—	—	1,402	—	—	—	—	—	1,402	
Deferred compensation	—	—	734	—	734	—	(817)	—	651	
Contribution to GP Holdings of investment in PVR	—	—	(475)	—	—	—	—	—	(475)	
Net income	—	—	—	75,909	—	—	—	—	75,909	$75,909
Other comprehensive gain, net of tax	—	—	—	—	—	1,200	—	—	1,200	1,200
Adoption of SFAS No. 158, net of tax (See Note 16)	—	—	—	—	—	(1,338)	—	—	(1,338)	
Balance at December 31, 2006	18,781	$ 188	$100,559	$289,967	$1,314	$(7,954)	$(1,649)	$ —	$382,425	$77,109

See accompanying notes to consolidated financial statements

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2006	2005	2004
Cash flows from operating activities			
Net income	$ 75,909	$ 62,088	$ 33,355
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	94,217	76,937	54,952
Commodity derivative contracts:			
Total derivative losses (gains)	(17,535)	28,803	5,886
Cash settlements of derivatives	(8,947)	(19,586)	(5,886)
Deferred income taxes	38,020	17,094	19,225
Minority interest	43,018	30,389	19,023
Impairment of oil and gas properties	8,517	4,785	655
Loss on assets held for sale	—	—	7,541
Dry hole and unproved leasehold expense	24,502	29,736	16,010
Other	4,260	5,989	5,229
Changes in operating assets and liabilities:			
Accounts receivable	(1,770)	(52,671)	(12,603)
Other current assets	(2,643)	(876)	(1,781)
Accounts payable and accrued liabilities	30,116	43,475	2,996
Other assets and liabilities	(11,845)	5,244	1,763
Net cash provided by operating activities	275,819	231,407	146,365
Cash flows from investing activities			
Proceeds from the sale of property and equipment	2,604	17,385	1,559
Acquisitions, net of cash acquired	(195,166)	(290,938)	(28,442)
Additions to property and equipment	(269,773)	(184,386)	(125,241)
Other	—	—	767
Net cash used in investing activities	(462,335)	(457,939)	(151,357)
Cash flows from financing activities			
Dividends paid	(8,398)	(8,358)	(8,248)
Distributions paid to minority interest holders of PVR	(38,627)	(30,737)	(21,892)
Proceeds from issuance of partners' capital	117,818	126,456	—
Proceeds from borrowings of the Company	162,000	78,000	33,000
Repayments of borrowings of the Company	(20,000)	(75,000)	(21,000)
Proceeds from borrowings of PVR	85,800	288,800	28,500
Repayments of borrowings of PVR	(122,900)	(151,600)	(2,500)
Payments for debt issuance costs	(668)	(2,835)	(1,234)
Other	5,916	2,248	5,829
Net cash provided by financing activities	180,941	226,974	12,455
Net increase (decrease) in cash and cash equivalents	(5,575)	442	7,463
Cash and cash equivalents—beginning of period	25,913	25,471	18,008
Cash and cash equivalents—end of period	$ 20,338	$ 25,913	$ 25,471
Supplemental disclosures:			
Cash paid during the periods for:			
Interest (net of amounts capitalized)	$ 23,452	$ 12,978	$ 5,790
Income taxes	$ 16,741	$ 15,455	$ 4,148
Noncash investing activities:			
Deferred tax liabilities related to acquisition, net	$ 32,759	$ —	$ —
Issuance of PVR units for acquisition	$ —	$ 10,415	$ 1,060
Assumption of liabilities in acquisitions	$ —	$ 3,981	$ —

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent energy company that is engaged in three primary business segments. Our oil and gas segment explores for, develops, produces and sells crude oil, condensate and natural gas primarily in the Appalachian, Mississippi, Mid-Continent and Gulf Coast onshore areas of the United States. Our coal segment and natural gas midstream segment operate through Penn Virginia Resource Partners, L.P. ("PVR"). We own 100% of the general partner of Penn Virginia GP Holdings, L.P. ("PVG") and an approximately 82% limited partner interest in PVG. PVG owns 100% of the general partner of PVR, which holds a 2% percent general partner interest in PVR, and an approximately 42% limited partner interest in PVR. Because we control PVG, the financial results of PVG are included in our consolidated financial statements. Because PVG controls the general partner of PVR, the financial results of PVR are included in PVG's consolidated financial statements. However, PVR and PVG function with a capital structure that is 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.

In the coal segment, PVR does not operate any mines. Instead, PVR enters into leases with various third-party operators which give those operators the right to mine coal reserves on PVR's land in exchange for royalty payments. PVR also provides fee-based infrastructure facilities to some of its lessees and third parties to generate coal services revenues. These facilities include coal loading facilities, preparation plants and coal handling facilities located at end-user industrial plants. PVR also sells timber growing on its land.

PVR purchased its midstream business on March 3, 2005, through the acquisition of Cantera Gas Resources, LLC (see Note 4). As a result of this acquisition, PVR owns and operates a significant set of midstream assets. PVR's 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.

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

PVR is a Delaware limited partnership formed by us in July 2001 primarily to engage in the business of managing coal properties in the United States. PVR completed its initial public offering (the "PVR IPO") in October 2001. Effective with the closing of the PVR IPO, we, through our wholly owned subsidiaries, received common and subordinated units of PVR and a 2% general partner interest in PVR. The general partner of PVR is Penn Virginia Resource, GP, LLC, who was a wholly owned subsidiary of us at the time of the PVR IPO.

In December 2006, our wholly owned subsidiary, completed its initial public offering (the "PVG IPO"), selling approximately 18% of its outstanding common units to the public. PVG used the offering proceeds to purchase PVR common and Class B units. Our other subsidiaries contributed to PVG their general partner and limited partner interests in PVR in exchange for general partner and limited partner interests in PVG. As of December 31, 2006, PVG owned approximately 44% of PVR, consisting of a 2% general partner interest and an approximately 42% limited partner interest. As part of its ownership of PVR's general partner, PVG also owns the rights, referred to as "incentive distribution rights," to receive an increasing percentage of PVR's quarterly distributions of available cash from operating surplus after certain levels of cash distributions have been achieved. As of December 31, 2006, we and our subsidiaries owned approximately 82% of PVG and the non-economic general partner interest in PVG. PVG's partnership agreement does not provide for incentive distribution rights.

The PVR common units have preferences over the PVR subordinated units with respect to cash distributions; accordingly, we accounted for the sale of PVR IPO units as a sale of a minority interest. At the time of the PVR IPO, we computed a gain of $25.6 million under SEC Staff Accounting Bulletin Topic 5-H, *Accounting for Sales of Stock by a Subsidiary*, which is included in minority interest. In November 2004, 25% of the subordinated units converted to common units, and another 25% converted in November 2005, as PVR met certain requirements to qualify for early conversion. The remaining 50% converted to common units in November 2006. In each of the years 2005 and 2004, $6.4 million of the $25.6 million gain were reclassified from minority interest to paid-in capital upon the conversion of the PVR subordinated units, for a cumulative reclassification of $12.8 million as of December 31, 2005. Because the issuance of Class B units was contemplated at the time the final PVR subordinated units converted to PVR common units in November 2006, we did not recognize the remaining $12.8 million gain at that time. Rather, the remaining $12.8 million of gain will be recognized in partners' capital when PVR has no form of subordinated securities outstanding, including the Class B units issued to PVG in December 2006.

In March 2005, PVR issued 2.5 million common units in a public offering, which constitutes a sale of a minority interest from our perspective. PVR also issued common units in connection with an acquisition in 2005 (see Note 4). We will recognize an additional gain resulting from the March 2005 public offering and issuance of units in the acquisition when PVR has no form of subordinated securities outstanding, including the Class B units issued to PVG in December 2006. At that time, the gain will be reclassified from minority interest to paid-in capital.

3. Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of Penn Virginia and all its wholly-owned subsidiaries, PVG and PVR. We own and operate our undivided oil and gas reserves through our wholly-owned subsidiaries. We account for our undivided interest in oil and gas properties on a proportionate consolidation basis, whereby our share of assets, liabilities, revenues and expenses is included in the appropriate classification in the financial statements. Intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all adjustments have been reflected that are necessary for a fair presentation of the consolidated financial statements. Certain amounts have been reclassified to conform to the current year's presentation.

Prior to December 5, 2006, our ownership of PVR included our ownership of limited partner interests in PVR and our ownership of Penn Virginia Resource GP, LLC, which is PVR's general partner and owns the incentive distribution rights in PVR. Our sole ownership of Penn Virginia Resource GP, LLC provided us with a 2% general partner interest in PVR. Our general partner interest gave us control of PVR as the holders limited partner interests of PVR: (i) do not have the substantive ability to dissolve PVR, (ii) can remove Penn Virginia Resource GP, LLC as PVR's general partner only with a supermajority vote of the PVR limited partner interests and the PVR limited partner interests which can be voted in such an election are restricted, and (iii) the PVR limited partners do not possess substantive participating rights in PVR's operations. Therefore, our consolidated financial statements prior to December 5, 2006 include the assets, liabilities and cash flows of Penn Virginia Resource GP, LLC and PVR.

After PVG sold 18% of its outstanding common units to the public on December 4, 2006, our ownership of PVR and PVG decreased. Our ownership of PVG includes our ownership of limited partner interests in PVG and our ownership of PVG GP, LLC, which is PVG's general partner. Our sole ownership of PVG GP, LLC provides us with a non-economic general partner interest in PVG. Our general partner interest gives us control of PVG as the holders of limited partner interests in PVG: (i) do not have the substantive ability to dissolve PVG, (ii) can remove PVG GP, LLC as PVG's general partner only with a supermajority vote of the PVG limited partner interest and the PVG limited partner interest which can be voted in such an election are restricted, and (iii) the PVG limited partners do not possess substantive participating rights in PVG's operations. Therefore, our consolidated financial statements after December 4, 2006 include the assets, liabilities and cash flows of PVG and PVR.

PVG's only cash-generating assets are its ownership interest in Penn Virginia Resource GP, LLC, which owns the general partner interest and incentive distribution rights in PVR, and its ownership of limited partner interests in PVR. Therefore, PVG's cash flows are dependent upon PVR's ability to make cash distributions, and the distributions PVG receives are subject to PVR's cash distribution policies.

The minority interests of subsidiaries on our balance sheet reflects the outside ownership interest of PVG and PVR as of December 31, 2006 and the outside ownership interest of PVR as of December 31, 2005 when taking into consideration the allocations made related to Penn Virginia Resource GP, LLC's incentive distribution rights. PVG's outside ownership interest was 18% at December 31, 2006. PVR's outside ownership interest was 56% at December 31, 2006 and 61% at December 31, 2005.

Use of Estimates

Preparation of the accompanying 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 the 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.

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 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 they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. As of December 31, 2006, we had capitalized $1.1 million of exploratory drilling costs related to one exploratory well, which reached total depth in 2006 but was under evaluation for commercial viability.

The following table describes the changes in capitalized exploratory drilling costs that are pending the determination of proved reserves (in thousands, except wells):

	2006		2005		2004	
	#Wells	Cost	#Wells	Cost	#Wells	Cost
Balance at beginning of period	3	$ 1,670	3	$ 3,079	10	$ 3,785
Additions pending determination of proved reserves	1	1,119	3	1,670	3	3,079
Reclassifications to wells, equipment and facilities based on the determination of proved reserves	—	—	—	—	—	—
Charged to expense	(3)	(1,670)	(3)	(3,079)	(10)	(3,785)
Balance at end of period	1	$ 1,119	3	$ 1,670	3	$ 3,079

We had no capitalized exploratory drilling costs that had been under evaluation for a period greater than one year as of December 31, 2006, 2005 or 2004.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Interest costs associated with non-producing leases were capitalized in the amounts of $2.8 million, $3.5 million and $2.0 million in 2006, 2005 and 2004. 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 expensed. The timing of any writedowns of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results. As of December 31, 2006 and 2005, unproved leasehold costs amounted to $100.0 million and $66.7 million.

Other Property and Equipment

Other property and equipment primarily consist of PVR's ownership in coal fee mineral interests, PVR's royalty interest in oil and natural gas wells, processing facilities, gathering systems, compressor stations 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 expensed as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. We compute depreciation and amortization of property and equipment using the straight-line or declining balance method over the estimated useful life of each asset as follows:

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

We deplete coal properties on an area-by-area basis at a rate based upon the cost of the mineral properties and estimated proven and probable tonnage therein. From time to time, PVR carries out core-hole drilling activities on coal properties in order to ascertain the quality and quantity of the coal contained in those properties. These core-drilling activities are expensed as incurred. When we retire or sell an asset, we remove its cost and related accumulated depreciation and amortization from the balance sheet. We record the difference between the net book value (net of any related asset retirement obligation) and proceeds from disposition as gain or loss.

Asset Retirement Obligations

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* we recognize the fair value of a liability for an asset retirement obligation (an "ARO") in the period in which it is incurred. The determination of fair value is based upon regional market and specific well type information. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. See Note 12, "Asset Retirement Obligations." The amount of an ARO and the costs capitalized equal 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 an assumed cost of funds for us. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds, and the additional capitalized costs is depreciated over the productive life of the assets. Both the accretion and the depreciation are included in depreciation, depletion and amortization expense on our consolidated statements of income.

Impairment of Long-Lived Assets

We review long-lived assets to be held and used whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. We recognize an impairment loss when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, we recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the present value of future net cash flows from proved reserves, discounted utilizing a rate commensurate with the risk and remaining lives for the respective oil and gas properties or other assets. See Note 8.

Equity Investments

We use the equity method of accounting to account for PVR's investment in a coal handling joint venture, recording PVR's initial investment at cost. Subsequently, the carrying amount of the investment is increased to reflect PVR's share of income of the investee and is reduced to reflect PVR's share of losses of the investee or distributions received from the investee as the joint venture reports them. PVR's share of earnings or losses from the investment is included in other revenues on the consolidated statements of income. Other revenues also include amortization of the amount of PVR's equity investment that exceeds its portion of the underlying equity in net assets. PVR records amortization over the life of coal services contracts in place at the time of PVR's initial investment.

Goodwill

We had approximately $7.7 million of goodwill at December 31, 2006 and 2005. The goodwill has been allocated to the natural gas midstream segment. In accordance with SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill is assessed at least annually for impairment. We tested goodwill for impairment during the fourth quarter of 2006 and determined that no impairment charge was necessary.

Intangibles

Intangible assets at December 31, 2006 and 2005 included $37.7 million for customer contracts and relationships acquired in the Cantera Acquisition (see Note 4) and the Alloy Acquisition (see Note 5) and $4.6 million for rights-of-way acquired in the Cantera Acquisition (see Note 4). Customer contracts and relationships are amortized on a straight-line basis over the expected useful lives of the individual contracts and relationships, up to 15 years. Rights-of-way are amortized on a straight-line basis over a period of 15 years. Total amortization expense for the years ended December 31, 2006 and 2005 was approximately $5.0 million and $4.2 million. There were no intangible assets or related amortization in 2004. As of December 31, 2006, accumulated amortization of intangible assets was $9.2 million. The following table summarizes our estimated aggregate amortization expense for the next five years (in thousands):

2007	$ 4,106
2008	3,485
2009	3,219
2110	3,006
2111	2,764
Thereafter	16,465
Total	$33,045

Concentration of Credit Risk

Approximately 52% of our consolidated accounts receivable at December 31, 2006 resulted from oil and gas sales and joint interest billings to third party companies in the oil and gas industry. Approximately 39% of our consolidated accounts receivable resulted from natural gas midstream customers, and the remaining 9% resulted from accrued revenues from PVR's coal lessee production. 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. In determining whether or not to require collateral from a customer, joint interest owner or lessee, we analyze the entity's net worth, cash flows, earnings and credit ratings to the extent information is available. Receivables are generally not collateralized. Historical credit losses incurred on receivables have not been significant.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments and long-term debt. The carrying values of all of these financial instruments, except for PVR's fixed rate long-term debt, approximate fair value. The fair value of PVR's fixed rate long-term debt at December 31, 2006 and 2005, was $75.4 million and $81.2 million.

Revenues

Oil and Gas Revenues. Revenues associated with sales of natural gas, crude oil, condensate and natural gas liquids are recorded when title passes to the customer. Natural gas sales revenues from properties in which we have an interest with other producers are recognized 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. Any amount received in excess of our share is treated as deferred revenues. If we take less than we are entitled to take, the under-delivery is recorded 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, accruals for revenues and accounts receivable are made 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. Any differences, which we do not expect to be significant, between the actual amounts ultimately received and the original estimates are recorded in the period they become finalized.

Natural Gas Midstream Revenues. Revenues from the sale of natural gas liquids ("NGLs") and residue gas are recognized 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 gas purchased and accounts payable based on estimates of natural gas purchased and NGLs and residue gas sold, and our financial results include estimates of production and revenues for the period of actual production. We record any differences, which have not historically been significant, between the actual amounts ultimately received or paid and the original estimates in the period they become finalized.

Coal Royalties. Coal royalty revenues are recognized on the basis of tons of coal sold by PVR's lessees and the corresponding revenues from those sales. Most of PVR's coal leases are based on minimum monthly or annual rental payments, a minimum dollar royalty per ton and/or a percentage of the gross sales price. The remainder of PVR's coal royalty revenues was derived from fixed royalty rate leases, which escalate annually, with pre-established minimum monthly payments. Coal royalty revenues are accrued on a monthly basis, based on PVR's best estimates of coal mined on its properties.

Coal Services. Coal services revenues are recognized when lessees use PVR's facilities for the processing, loading and/or transportation of coal. Coal services revenues consist of fees collected from PVR's lessees for the use of PVR's loadout facility, coal preparation plants and dock loading facility. Coal services revenues are included in other revenues on the consolidated statements of income.

Equity Earnings. PVR recognizes its share of income or losses from its investment in a coal handling joint venture as the joint venture reports them to PVR. Equity earnings are included in other revenues.

Minimum Rentals. Most of PVR's lessees must make minimum monthly or annual payments that are generally recoupable over certain time periods. These minimum payments are recorded as deferred income. If the lessee recoups a minimum payment through production, the deferred income attributable to the minimum payment is recognized as coal royalty revenues. If a lessee fails to meet its minimum production for certain pre-determined time periods, the deferred income attributable to the minimum payment is recognized as minimum rental revenues and is included in other revenues.

Hedging Activities

From time to time, we 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 major financial institutions that we believe are minimum credit risks, take the form of costless collars, three-way collars and swaps. All derivative financial instruments are recognized in the financial statements at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. The fair values of our derivative instruments are determined based on third party forward price quotes. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our Board of Directors.

We and PVR have historically entered into derivative financial instruments that would qualify for hedge accounting under SFAS No. 133. Hedge accounting affects the timing of revenue recognition and cost of midstream gas purchased in our consolidated statements of income, as a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred until the related hedged transaction occurs. Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements, we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). Because we no longer use hedge accounting for our commodity derivatives, we could experience significant changes in the estimate of derivative gain or loss recognized in revenues and cost of midstream gas purchased due to swings in the value of these contracts. These fluctuations could be significant in a volatile pricing environment.

The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

Income Tax

We account for income taxes in accordance with the provisions of SFAS No. 109, *Accounting for Income Taxes*, which requires a company to 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.

Stock-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 (see Note 18). Prior to January 1, 2006, we accounted for those plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations, as permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*. Stock-based compensation cost included in our statements of income prior to 2006 included only costs related to restricted stock and deferred common stock units. Prior to 2006, we did not recognize expense for options as permitted by SFAS No. 123 because all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006 based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123 and (b) compensation cost for all share-based payments granted on or after January 1, 2006 based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R), *Share-Based Payment*. Results for prior periods have not been restated.

The general partner of PVG has a long-term incentive plan that permits the grant of awards to employees and directors of PVG's general partner and employees of its general partner's affiliates who perform services for PVG. Awards under this 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. PVG recognizes compensation cost based on the fair value of the awards in accordance with SFAS No. 123(R).

The general partner of PVR has a long-term incentive plan that permits the grant of awards to employees and directors of PVR's general partner and employees of its affiliates who perform services for PVR. Awards under this 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. PVR recognizes compensation cost based on the fair value of the awards and accordance with SFAS No. 123(R).

New Accounting Standards

In December 2004, the Financial Accounting Standards Board (the "FASB") issued the final revised version of SFAS No. 123(R), which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. In March 2005, the SEC issued Staff Accounting Bulletin ("SAB") No. 107, *Share-Based Payment*, regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations. Effective January 1, 2006, we adopted SFAS No. 123(R). Beginning January 1, 2006, we recognize compensation expense related to share-based payments on a straight-line basis over the requisite service period for share-based payment awards granted after the effective date of SFAS No. 123(R). For unvested stock options granted prior to the effective date of SFAS No. 123(R), we recognize compensation expense in the same manner as was used for pro forma disclosures prior to the effective date of SFAS No. 123(R). See Note 18 for more information regarding the adoption of SFAS No. 123(R).

In July 2006, the FASB issued Interpretation 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 creates a single model to address uncertainty in income tax positions. FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position is required to meet before being recognized in the financial statements. It also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition and clearly scopes income taxes out of SFAS No. 5, *Accounting for Contingencies.* FIN 48 is effective for fiscal years beginning after December 15, 2006. We have not yet determined the impact on our consolidated financial statements of adopting FIN 48 effective January 1, 2007.

In September 2006, the FASB issued FASB Staff Position ("FSP") AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* FSP AUG AIR-1 prohibits companies from accruing as a liability the future costs of periodic major overhauls and maintenance of plant and equipment. FSP AUG AIR-1 is effective for fiscal years beginning after December 15, 2006. We expect that the provisions of FSP AUG AIR-1 will not have a material impact on our consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements,* a standard that provides enhanced guidance for using fair value to measure assets and liabilities. SFAS No. 157 also responds to investors' requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. SFAS No. 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop fair value assumptions. SFAS No. 157 is effective for fiscal years and interim periods beginning after November 15, 2007. We have not yet determined the impact on our financial statements of adopting SFAS No. 157 effective January 1, 2008.

In September 2006, the SEC issued SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB No. 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant's approach. SAB No. 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006. We adopted SAB No. 108 as of December 31, 2006. Adoption of SAB No. 108 had no effect on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* SFAS No. 158 requires plan sponsors of defined benefit pension and other postretirement benefit plans (collectively, "postretirement benefit plans") to recognize the overfunded or underfunded status of their postretirement benefit plans in the statement of financial position, measure the fair value of plan assets and benefit obligations as of the end of the plan sponsor's fiscal year, recognize in comprehensive income changes in the funded status of postretirement benefit plans in the year in which the changes occur and provide additional disclosures. On

December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158. The effect of adopting SFAS No. 158 on our financial position at December 31, 2006 has been included in the accompanying consolidated financial statements. SFAS No. 158 did not have an effect on our consolidated financial position at December 31, 2005 or 2004. SFAS No. 158's provisions regarding the change in the measurement date of postretirement benefit plans are not applicable as we already use a measurement date of December 31 for our postretirement benefit plans. See Note 16 for further discussion of the effect of adopting SFAS No. 158 on our consolidated financial statements.

4. Acquisition of Natural Gas Midstream Business

On March 3, 2005, PVR completed its acquisition (the "Cantera Acquisition") of Cantera Gas Resources, LLC ("Cantera"), a midstream gas gathering and processing company with primary locations in Oklahoma and Texas. The midstream business operates as PVR Midstream LLC, a subsidiary of Penn Virginia Operating Co., LLC, which is a wholly owned subsidiary of PVR. As a result of the Cantera Acquisition, PVR owns and operates a significant set of midstream assets including gas gathering pipelines and three natural gas processing facilities. PVR's 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. The results of operations of PVR Midstream LLC since March 3, 2005, the closing date of the Cantera Acquisition, are included in the accompanying consolidated statements of income.

Cash paid in connection with the Cantera Acquisition was $199.2 million, net of cash received and including capitalized acquisition costs, which PVR funded with a $110 million term loan and with borrowings under PVR's revolving credit facility. PVR used proceeds of $126.4 million from PVR's sale of common units in a subsequent public offering in March 2005 and a $2.6 million contribution from its general partner to repay the term loan in full and to reduce outstanding indebtedness under its revolving credit facility. The total purchase price was allocated to the assets purchased and the liabilities assumed in the Cantera Acquisition based upon the fair values on the date of acquisition as follows (in thousands):

Cash consideration paid for Cantera	$201,326
Plus: Acquisition costs	3,275
Total purchase price	204,601
Less: Cash acquired	(5,378)
Total purchase price, net of cash acquired	$199,223
Current assets acquired	$ 43,697
Property and equipment acquired	145,448
Other assets acquired	645
Liabilities assumed	(38,337)
Intangible assets	40,052
Goodwill	7,718
Total purchase price, net of cash acquired	$199,223

The purchase price allocation includes approximately $7.7 million of goodwill. The significant factors that contributed to the recognition of goodwill include PVR's entry into the natural gas midstream business and its ability to acquire an established business with an assembled workforce.

Under SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, goodwill recorded in connection with a business combination is not amortized, but rather is tested for impairment at least annually. Accordingly, the unaudited pro forma financial information presented below does not include amortization of the goodwill recorded in the Cantera Acquisition. The purchase price allocation also includes $40.1 million of intangible assets that are primarily associated with assumed customer contracts, customer relationships and rights of way. These intangible assets are being amortized over periods of up to 15 years, the period in which benefits are derived from the contracts, relationships and rights-of-way assumed, and are reviewed for impairment under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

The following unaudited pro forma financial information reflects our consolidated results of operations as if the Cantera Acquisition and related debt and equity financings had occurred on January 1 of the reported period. The pro forma information includes adjustments primarily for depreciation of acquired property and equipment, amortization of intangibles and interest expense for acquisition debt. 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 (in thousands, except share data).

	Year Ended December 31,	
	2005	2004
Revenues	$692,228	$299,950
Net income	$ 62,179	$ 36,177
Net income per share, basic	$ 3.35	$ 1.98
Net income per share, diluted	$ 3.32	$ 1.96

5. Other Acquisitions

In the following paragraphs, all references to coal, oil and natural gas reserves and acreage acquired are unaudited.

Oil and Gas Segment

In June 2006, we acquired 100% of the capital stock of Crow Creek Holding Corporation ("Crow Creek") in a cash transaction for approximately $71.5 million (the "Crow Creek Acquisition"). The preliminary purchase price allocation is subject to certain adjustments that primarily relate to the determination of tax basis and the allocation between proved and unproved property. Crow Creek was a privately owned independent exploration and production company with operations primarily in the Oklahoma portions of the Arkoma and Anadarko Basins. The Crow Creek assets primarily included approximately 42.7 Bcfe of net proved reserves, approximately 85% of which were natural gas. The Crow Creek Acquisition was funded with long-term debt under our revolving credit facility.

In June 2005, we acquired approximately 60,000 acres of prospective CBM leasehold rights in Wyoming County, West Virginia from Panther Energy Company, LLC for $13.3 million in cash (the "Panther Acquisition"). The leasehold acreage is within an area of mutual interest between Penn Virginia and CDX Gas, LLC ("CDX") and is contiguous to acreage which has been successfully developed. The purchase agreement included an option for CDX to purchase a 50% interest in the leasehold acreage. In August 2005, CDX exercised that option and acquired its 50% interest for $6.6 million in cash. We began drilling on the new leasehold position in the fourth quarter of 2005.

PVR Coal Segment

In December 2006, PVR acquired ownership and rights to approximately 22 million tons of coal reserves. The reserves are located in Henderson County, Kentucky. The purchase price was $9.3 million and was funded with cash.

In May 2006, PVR acquired the lease rights to approximately 69 million tons of coal reserves located on approximately 20,000 acres in Boone, Logan and Wyoming Counties, West Virginia. The purchase price was $65.0 million and was funded with long-term debt under PVR's revolving credit facility.

In July 2005, PVR also acquired fee ownership of approximately 94 million tons of coal reserves in the western Kentucky portion of the Illinois Basin for $62.4 million in cash (the "Green River Acquisition") and the assumption $3.3 million of deferred income. This coal reserve acquisition is PVR's first in the Illinois Basin and was funded with long-term debt under PVR's revolving credit facility. Currently, approximately 41 million tons of these coal reserves are leased to affiliates of Peabody Energy Corporation (NYSE: BTU).

In July 2005, PVR acquired a combination of fee ownership and lease rights to approximately 16 million tons of coal reserves for $14.5 million (the "Wayland Acquisition"). The reserves are located in the eastern Kentucky portion of Central Appalachia. The Wayland Acquisition was funded with $4 million of cash and PVR's issuance to the seller of approximately 209,000 common units.

In April 2005, PVR acquired fee ownership of approximately 16 million tons of coal reserves for $15.0 million in cash (the "Alloy Acquisition"). The reserves, located on approximately 8,300 acres in the Central Appalachia region of West Virginia, will be produced from deep and surface mines. Production started in late 2005. Revenues were earned initially from transportation-related fees on coal mined from an adjacent property, followed by royalty revenues as the mines on PVR's property commenced production. The seller remained on the property as the lessee and operator. The Alloy Acquisition was funded with long-term debt under PVR's revolving credit facility.

In March 2005, PVR acquired lease rights to approximately 36 million tons of undeveloped coal reserves and royalty interests in 73 producing oil and natural gas wells for $9.3 million in cash (the "Coal River Acquisition"). The coal reserves are located in the central Appalachia region of southern West Virginia. The oil and gas wells are located in eastern Kentucky and southwestern Virginia. The Coal River Acquisition was funded with long-term debt under PVR's revolving credit facility. The coal reserves are predominantly low sulfur and high BTU content, and development will occur in conjunction with PVR's adjacent reserves and a related loadout facility that was placed into service in 2004. The oil and gas property contained approximately 2.8 billion cubic feet equivalent of net proved oil and gas reserves.

In July 2004, PVR acquired from affiliates of Massey Energy Company a 50% interest in a joint venture formed to own and operate end-user coal handling facilities. The purchase price was $28.4 million and was funded with long-term debt under PVR's revolving credit facility. The joint venture owns coal handling facilities which unload coal shipments and store and transfer coal for three industrial coal consumers in the chemical, paper and lime production industries located in Tennessee, Virginia and Kentucky. A combination of fixed monthly fees and per ton throughput fees is paid by those consumers under long-term leases expiring between 2007 and 2019.

PVR Midstream Segment

In June 2006, PVR completed the acquisition of approximately 115 miles of gathering pipelines and related compression facilities in Texas and Oklahoma (the "Transwestern Acquisition"). These assets are contiguous to PVR's Beaver/Perryton System. PVR paid $14.7 million in cash for the acquisition. Subsequently, PVR borrowed $14.7 million under its revolving credit facility to replenish the cash used in the Transwestern Acquisition.

The factors 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.

6. Sale of Texas Properties

In January 2005, we completed the sale of certain oil and gas properties in Texas for cash proceeds of $9.7 million. These properties were classified as assets held for sale, and we recognized a $7.5 million loss on assets held for sale in 2004 in order to write down the assets to fair market value less costs to sell.

7. Property and Equipment

Property and equipment includes:

	December 31,	
	2006	2005
	(in thousands)	
Oil and gas properties		
Proved	$ 945,174	$ 650,696
Unproved	100,008	66,727
Total oil and gas properties	1,045,182	717,423
Other property and equipment:		
Coal properties	414,935	340,439
Midstream property and equipment	189,811	151,154
Other property and equipment	55,132	35,767
Land	11,291	10,675
Total property and equipment	1,716,351	1,255,458
Accumulated depreciation, depletion and amortization	(357,968)	(272,239)
Net property and equipment	$1,358,383	$ 983,219

8. Impairment of Oil and Gas Properties

In accordance with SFAS No. 144, 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. When we find that the carrying amounts of the properties exceed their estimated undiscounted future cash flows, we adjust the carrying amounts of the properties to their fair value as determined by discounting their estimated future cash flows. The factors used to determine fair value include, but are not limited to, estimates of proved 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.

For the year ended December 31, 2006, we recognized a pretax charge of $8.5 million related to the impairment of certain properties in Louisiana, Texas and West Virginia. These impairments were a result of downward reserve revisions on the properties.

For the year ended December 31, 2005, we recognized a pretax charge of $4.8 million related to the impairment of certain properties in Texas. This impairment was a result of downward reserve revisions on the properties.

For the year ended December 31, 2004, we recognized a pretax charge of $0.7 million related to the impairment of certain West Virginia horizontal coalbed methane ("CBM") properties. This impairment was associated with a CBM well completed in 2004 in northern West Virginia that had insufficient natural gas reserves to support the historical cost basis of the property.

9. Equity Investments

As described in Note 5, "Other Acquisitions," PVR acquired a 50% interest in Coal Handling Solutions, LLC, a joint venture formed to own and operate end-user coal handling facilities. PVR accounts for the investment under the equity method of accounting. In 2004, the original cash investment of $28.4 million was capitalized. At December 31, 2006 and 2005, PVR's equity investment totaled $25.4 million and $26.7 million, which exceeded its portion of the underlying equity in net assets by $8.7 million and $10.7 million. The difference is being amortized to equity earnings over the life of coal services contracts in place at the time of the acquisition. In accordance with the equity method, PVR recognized equity earnings of $1.3 million in 2006, $1.1 million in 2005 and $0.4 million in 2004 with a corresponding increase in the investment. The joint venture generally pays to PVR quarterly distributions of PVR's portion of the joint venture's cash flows. PVR received cash distributions from the joint venture of $2.7 million, $2.3 million and $1.0 million in 2006, 2005 and 2004. Equity earnings are included in other revenues on the consolidated statements of income.

10. Derivative Instruments

Discontinuation of Hedge Accounting

Because during the first quarter of 2006 a large portion of our natural gas derivatives and NGL derivatives no longer qualified for hedge accounting and to increase clarity in our consolidated financial statements (see below for further discussions), we elected to discontinue hedge accounting prospectively for our remaining commodity derivatives beginning May 1, 2006. Consequently, from that date forward, we began recognizing mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income (shareholders' equity). The net mark-to-market loss on our outstanding derivatives at April 30, 2006, which was included in accumulated other comprehensive income, will be reported in future earnings through 2008 as the original hedged transactions settle. This change in reporting will have no impact on our reported cash flows, although future results of operations will be affected by the volatility of mark-to-market gains and losses which fluctuate with changes in NGL, oil and gas prices.

The following table summarizes the effects of commodity derivative activities on our consolidated statements of income:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Income statement caption:			
Natural gas revenues	$ 448	$(14,049)	$(3,770)
Oil and condensate revenues	(457)	(857)	(2,116)
Midstream revenues	(10,331)	(3,871)	—
Cost of gas purchased	8,378	4,859	—
Derivatives	19,497	(14,885)	—
Decrease in income before minority interest and income taxes	$ 17,535	$(28,803)	$(5,886)
Realized and unrealized derivative impact:			
Cash paid for derivative settlements	$ (8,947)	$(19,586)	$(5,886)
Unrealized derivative gain (loss)	26,482	(9,217)	—
Decrease in income before minority interest and income taxes	$ 17,535	$(28,803)	$(5,886)

Oil and Gas Segment Commodity Derivatives

We utilize costless collars, three-way collars and swap derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a costless collar contract, the counterparty 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 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. A three-way collar contract consists of a collar contract as described above plus a put option contract sold by us with a price below the floor price of the collar. This additional put 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. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional collar contract while defraying the associated cost with the sale of the additional put option. With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract.

The fair values of our oil and gas derivative agreements are determined based on third party forward price quotes for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of December 31, 2006. The following table sets forth our positions as of December 31, 2006:

	Average Volume Per Day	Weighted Average Price: Additional Put Option	Weighted Average Price: Floor	Weighted Average Price: Ceiling	Estimated Fair Value (in thousands)
	(in Mmbtus)	(per Mmbtu)			
Natural Gas Costless Collars					
First Quarter 2007	30,000		$ 8.50	$16.35	$ 6,208
Second Quarter 2007	15,000		$ 7.33	$12.93	1,576
Third Quarter 2007	15,000		$ 7.33	$12.93	1,547
Fourth Quarter 2007	11,685		$ 8.28	$15.78	1,525
First Quarter 2008	10,000		$ 9.00	$17.95	1,312
	(in Mmbtus)	(per Mmbtu)			
Natural Gas Three-way Collars					
First Quarter 2007	13,000	$5.00	$ 7.62	$10.15	1,712
Second Quarter 2007	33,000	$5.00	$ 7.55	$ 9.05	2,537
Third Quarter 2007	33,000	$5.00	$ 7.55	$ 9.05	1,667
Fourth Quarter 2007	19,379	$5.17	$ 7.74	$10.43	614
First Quarter 2008	12,500	$5.40	$ 8.00	$12.15	125
Second Quarter 2008	2,500	$5.00	$ 8.00	$10.75	201
Third Quarter 2008	2,500	$5.00	$ 8.00	$10.75	173
Fourth Quarter 2008	2,500	$5.00	$ 8.00	$10.75	79
	(in Mmbtus)	(per Mmbtu)			
Natural Gas Swaps					
First Quarter 2007	5,000		$ 7.12		407
	(in barrels)	(per barrel)			
Crude Oil Costless Collars					
First Quarter 2007	200		$60.00	$72.20	20
Second Quarter 2007	200		$60.00	$72.20	8
Third Quarter 2007	200		$60.00	$72.20	(7)
Fourth Quarter 2007	200		$60.00	$72.20	(20)
Oil and gas segment commodity derivatives—net asset					$19,684

Based upon our assessment of derivative agreements at December 31, 2006, we reported (i) a net derivative asset of $19.7 million and (ii) a loss in accumulated other comprehensive income of $0.2 million, net of a related income tax benefit of $0.1 million.

At the time we entered into our natural gas derivatives, physical sales prices correlated well with NYMEX natural gas prices; however, beginning in the second half of 2005, basis differentials for certain derivative agreements widened as NYMEX natural gas prices reached historically high levels. In the first quarter of 2006, our correlation assessment indicated that certain NYMEX natural gas derivatives could no longer be considered "highly effective" hedges under the parameters of the accounting rules. Consequently, we discontinued hedge accounting effective January 1, 2006 for certain natural gas derivatives that were no longer considered highly effective. As discussed above, beginning May 1, 2006, we elected to discontinue hedge accounting prospectively for our remaining and future commodity derivatives. We will recognize hedging losses of $0.3 million in 2007 related to settlements of the oil and gas segment's hedged transactions for which we deferred net losses in accumulated other comprehensive income through April 30, 2006.

PVR Natural Gas Midstream Segment Commodity Derivatives

PVR also utilizes swap contracts in its natural gas midstream business. The fair values of PVR's derivative agreements are determined based on forward price quotes and regression analysis for the respective commodities as of December 31, 2006. The following table sets forth PVR's positions as of December 31, 2006 for commodities related to natural gas midstream revenues (ethane, propane and crude oil) and cost of midstream gas purchased (natural gas):

	Average Volume Per Day	Weighted Average Price	Estimated Fair Value (in thousands)
	(in gallons)	(per gallon)	
Ethane Swaps			
First Quarter 2007 through Fourth Quarter 2007	34,440	$0.5050	(1,277)
First Quarter 2008 through Fourth Quarter 2008	34,440	$0.4700	(1,377)
	(in gallons)	(per gallon)	
Propane Swaps			
First Quarter 2007 through Fourth Quarter 2007	26,040	$0.7550	(1,543)
First Quarter 2008 through Fourth Quarter 2008	26,040	$0.7175	(1,795)
	(in barrels)	(per barrel)	
Crude Oil Swaps			
First Quarter 2007 through Fourth Quarter 2007	560	$ 50.80	(2,815)
First Quarter 2008 through Fourth Quarter 2008	560	$ 49.27	(3,446)
	(in MMbtu)	(per MMbtu)	
Natural Gas Swaps			
First Quarter 2007 through Fourth Quarter 2007	4,000	$ 6.97	(11)
First Quarter 2008 through Fourth Quarter 2008	4,000	$ 6.97	1,479
December 2006 Settlements			(1,350)
Natural gas midstream segment commodity derivatives—net liability			$(12,135)

Based upon our assessment of derivative agreements at December 31, 2006, we reported (i) a net derivative liability related to the natural gas midstream segment of $12.1 million, (ii) a loss in accumulated other comprehensive income of $6.5 million, net of a related income tax benefit of $3.5 million, and (iii) a net loss on derivatives for hedge ineffectiveness of $0.1 million for the year ended December 31, 2006 related to derivatives in the natural gas midstream segment.

At the time PVR entered into its natural gas derivatives and certain NGL derivatives, physical purchase prices of natural gas correlated well with NYMEX natural gas prices and physical sales prices of NGLs correlated well with NGL index prices. However, in the second half of 2005, basis differentials for certain derivative agreements widened as NYMEX natural gas prices and NGL index prices reached historically high levels. In the first quarter of 2006, PVR's correlation assessment indicated that its NYMEX natural gas derivatives and certain NGL derivatives could no longer be considered "highly effective" hedges under the parameters of the accounting rules. Consequently, PVR discontinued hedge accounting effective January 1, 2006 for its natural gas derivatives and certain NGL derivatives that were no longer considered highly effective. As discussed above, beginning May 1, 2006, PVR elected to discontinue hedge accounting prospectively for its remaining and future commodity derivatives. PVR will recognize hedging losses of $4.6 million in 2007 and $5.5 million in 2008 related to settlements of the PVR natural gas midstream segment's hedged transactions for which PVR deferred net losses in accumulated other comprehensive income through April 30, 2006.

Interest Rate Swaps—PVA

In August 2006, we entered into interest rate swap agreements (the "Revolver Swaps") to establish fixed rates on $50 million of the LIBOR-based portion of the outstanding balance on our revolving credit facility until December 2010. We pay a weighted average fixed rate of 5.34% on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the Revolver Swaps are recorded as interest expense. The Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings as interest expense. We reported (i) a derivative liability of approximately $0.6 million at December 31, 2006 and (ii) a loss in accumulated other comprehensive income of $0.4 million, net of related income tax benefit of $0.2 million, at December 31, 2006 related to the Revolver Swaps. In connection with periodic settlements, we recognized less than $0.1 million in net hedging gains in interest expense for the year ended December 31, 2006. Based upon future interest rate curves at December 31, 2006, we expect to realize $0.2 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.

Interest Rate Swaps—PVR

In September 2005, PVR entered into interest rate swap agreements (the "PVR Revolver Swaps") to establish fixed rates on $60 million of the portion of the outstanding balance on PVR's revolving credit facility that is based on the London Inter Bank Offering Rate ("LIBOR") until March 2010. PVR pays a weighted average fixed rate of 4.22% on the notional amount plus the applicable margin, and the counterparties pay a variable rate equal to the three-month LIBOR. Settlements on the PVR Revolver Swaps are recorded as interest expense. The PVR Revolver Swaps were designated as cash flow hedges. Accordingly, the effective portion of the change in the fair value of the swap transactions is recorded each period in other comprehensive income. The ineffective portion of the change in fair value, if any, is recorded to current period earnings as interest expense. We reported (i) a derivative asset of approximately $1.4 million at December 31, 2006 and (ii) a gain in accumulated other comprehensive income of $0.9 million, net of related income tax expense of $0.5 million, at December 31, 2006 related to the PVR Revolver Swaps. In connection with periodic settlements, PVR recognized $0.5 million in net hedging gains in interest expense for the year ended December 31, 2006. Based upon future interest rate curves at December 31, 2006, PVR expects to realize $0.4 million of hedging gains within the next 12 months. The amounts that PVR ultimately realizes will vary due to changes in the fair value of open derivative agreements prior to settlement.

11. Accrued Liabilities

Accrued liabilities are summarized as follows:

	December 31, 2006	December 31, 2005
	(in thousands)	
Drilling costs	$ 13,279	$ 7,720
Royalties	11,224	7,785
Production and franchise taxes	9,960	9,188
Compensation	6,293	5,418
Deferred income	6,999	5,073
Pipeline imbalance—PVR Midstream	685	2,504
Interest	2,149	1,960
Other	15,650	3,601
Total accrued liabilities	66,239	43,249
Accounts payable	88,470	71,429
Accounts payable and accrued liabilities	$154,709	$114,678

12. Asset Retirement Obligations

The table below reconciles the beginning and ending aggregate carrying amount of our asset retirement obligations, which are included in other liabilities on the consolidated balance sheets:

	Year ended December 31, 2006	Year ended December 31, 2005
	(in thousands)	
Balance at beginning of period	$4,676	$3,635
Liabilities incurred	1,737	389
Adoption of FIN 47	—	635
Liabilities settled	(16)	(280)
Accretion expense	350	297
Balance at end of period	$6,747	$4,676

13. Other Liabilities

Other liabilities are summarized in the following table:

	December 31, 2006	December 31, 2005
	(in thousands)	
Deferred income—PVR Coal	$ 6,592	$10,194
Asset retirement obligation	6,747	4,676
Pension	1,966	2,102
Post-retirement health care	3,891	2,058
Environmental liabilities	1,459	2,293
Other	5,348	3,125
Total other liabilities	$26,003	$24,448

14. Long-Term Debt

Long-term debt as of December 31, 2006 and 2005, consisted of the following:

	December 31, 2006	December 31, 2005
	(in thousands)	
Penn Virginia revolving credit facility, variable rate of 6.6 percent at December 31, 2006	$221,000	$ 79,000
PVR revolving credit facility, variable rate of 6.1 percent at December 31, 2006	143,200	172,000
PVR senior unsecured notes (1)	74,846	82,954
	439,046	333,954
Less: Current maturities	(10,832)	(8,108)
Total long-term debt	$428,214	$325,846

(1) Includes negative fair value adjustments of $0.6 million and $0.7 million as of December 31, 2006 and 2005 related to a former swap agreement that was designated as a fair value hedge. The swap agreement was settled in June 2005.

Penn Virginia Revolving Credit Facility

We have a revolving credit facility with a syndicate of financial institutions led by JP Morgan Chase Bank N.A. (the "Revolver") that is secured by a portion of our proved oil and gas reserves and matures in December 2010. Effective November 1, 2006, we amended our credit facility to increase the commitment from $200 million to $300 million and the borrowing base from $300 million to $400 million. We paid loan issue costs of $0.3 million related to the amendment, which were capitalized in other assets and will be amortized over the remaining term of the Revolver. We had $221.0 million outstanding under the Revolver as of December 31, 2006.

The Revolver is governed by a borrowing base calculation and is redetermined semi-annually. We have the option to elect interest at (i) LIBOR plus a Eurodollar margin ranging from 1.00 to 1.75%, based on the percentage of the borrowing base outstanding or (ii) the greater of the prime rate or federal funds rate plus a margin up to 0.50%. The weighted average interest rate on borrowings incurred during the year ended December 31, 2006 was approximately 6.4%. In 2006 and 2005, we incurred commitment fees of $0.4 million and $0.3 million on the unused portion of the Revolver. We capitalized $2.8 million, $3.5 million and $2.0 million of interest cost incurred in 2006, 2005 and 2004. The Revolver allows for the issuance of up to $20 million of letters of credit, of which $0.7 million were issued as of December 31, 2006.

The financial covenants under the Revolver require us to maintain levels of debt-to-earnings and impose dividend limitation restrictions. The Revolver contains various other covenants that limit, among other things, our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. As of December 31, 2006, we were in compliance with all of our covenants under the Revolver.

PVR Revolving Credit Facility

Concurrent with the closing of the Cantera Acquisition in March 2005, Penn Virginia Operating Co., LLC, the parent of PVR Midstream LLC and a subsidiary of PVR, entered into a new unsecured $260 million, five-year credit agreement with a syndicate of financial institutions led by PNC Bank, National Association ("PNC"). The new agreement consisted of a $150 million revolving credit facility (the "PVR Revolver") that was set to mature in March 2010 and a $110 million term loan. As of December 31, 2006, PVR had $143.2 million of outstanding borrowings under the PVR Revolver. During 2005, a portion of the PVR Revolver and the term loan were used to fund the Cantera Acquisition and to repay borrowings under PVR's previous credit facility. Proceeds of $126.4 million received from a subsequent public offering of 2.5 million of PVR's common units in March 2005 and a $2.6 million contribution from its general partner were used to repay the $110 million term loan and a portion of the amount outstanding under the PVR Revolver. In the fourth quarter of 2004, PVR paid loan issue costs of approximately $1.2 million related to the term loan, which were recorded as interest expense in 2004. The term loan cannot be re-borrowed. PVR used the proceeds from the sale of common units and Class B units to PVG in December 2006 to pay down $114.6 million of the PVR Revolver. The PVR Revolver is available for general partnership purposes, including working capital, capital expenditures and acquisitions, and includes a $10 million sublimit for the issuance of letters of credit. PVR had outstanding letters of credit of $1.6 million as of December 31, 2006. In 2006 and 2005, PVR incurred commitment fees of $0.4 million each year on the unused portion of the PVR Revolver.

In July 2005, PVR amended its credit agreement to increase the size of the commitment under the PVR Revolver from $150 million to $300 million and to increase its one-time option (upon receipt by the credit facility's administrative agent of commitments from one or more lenders) to expand the facility from $100 million to $150 million. The amendment also updated certain debt covenant definitions. The interest rate under the credit agreement remained unchanged and fluctuates based on PVR's ratio of total indebtedness to EBITDA. In December 2006, PVR further amended the credit agreement to achieve a more favorable interest rate and to extend the maturity date to December 2011. Interest is payable at a base rate plus an applicable margin of up to 0.75% if PVR selects the LIBOR-based borrowing option under the credit agreement or at a rate derived from LIBOR plus an applicable margin ranging from 0.75% to 1.75% if PVR selects the LIBOR-based borrowing option. The other terms of the credit agreement remained unchanged.

The financial covenants under the PVR Revolver require PVR to maintain specified levels of debt to consolidated EBITDA and consolidated EBITDA to interest. The financial covenants restricted PVR's additional borrowing capacity under the PVR Revolver to $257.0 million as of December 31, 2006. At the current $300 million limit on the PVR Revolver, and given the outstanding balance of $143.2 million and $1.6 million in letters of credit, PVR could borrow up to $155.2 million without exercising its one-time option to expand the PVR Revolver. In order to utilize the full extent of the $257.0 million borrowing capacity, PVR would need to exercise its one-time option to expand the PVR Revolver by $150 million. 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 distribution. In addition, the PVR Revolver contains various covenants that limit, among other things, PVR's ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of its business, acquire another company or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. As of December 31, 2006, PVR was in compliance with all of its covenants under the PVR Revolver.

PVR Senior Unsecured Notes

In March 2003, PVR closed a private placement of $90 million of senior unsecured notes (the "PVR Notes"). The PVR Notes initially bore interest at a fixed rate of 5.77% and mature over a ten-year period ending in March 2013, with semi-annual principal and interest payments. The PVR Notes contain various covenants similar to those contained in the PVR Revolver. The PVR Notes have an equal priority of payment as all other unsecured indebtedness of PVR, including the PVR Revolver. As of December 31, 2006, PVR was in compliance with all of the covenants.

In conjunction with the closing of the Cantera Acquisition, PVR amended the PVR Notes to allow PVR to enter the natural gas midstream business and to increase certain covenant coverage ratios, including the debt to EBITDA test. In exchange for this amendment, PVR agreed to a 0.25% increase in the fixed interest rate on the PVR Notes, from 5.77% to 6.02%. The amendment to the PVR Notes also requires that PVR obtain an annual confirmation of its credit rating, with a 1.00% increase in the interest rate payable on the PVR Notes in the event PVR's credit rating falls below investment grade. In March 2006, PVR's investment grade credit rating was confirmed as investment grade by Dominion Bond Rating Services.

Line of Credit

We have a $10 million line of credit with a financial institution, which had no borrowings against it as of December 31, 2006 and 2005. The line of credit is effective through June 2007 and is renewable annually. We increased the line of credit from $5 million to $10 million in June 2006. We have an option to elect a fixed rate LIBOR loan, floating rate LIBOR loan or base rate (as determined by the financial institution) loan.

Debt Maturities

Aggregate maturities of the principal amounts of long-term debt for the next five years and thereafter are as follows (in thousands):

2007	$ 11,000
2008	12,700
2009	14,100
2010	234,400
2011	154,000
Thereafter	13,400
	439,600
Terminated interest rate swap	(554)
Total debt, including current maturities	$439,046

15. Income Taxes

The provision for income taxes from continuing operations is comprised of the following:

	Year ended December 31,		
	2006	2005	2004
	(in thousands)		
Current income taxes			
Federal	$11,710	$21,708	$ 2,619
State	258	1,867	3
Total current	11,968	23,575	2,622
Deferred income taxes			
Federal	29,419	12,007	15,247
State	8,601	5,087	3,978
Total deferred	38,020	17,094	19,225
Total income tax expense	$49,988	$40,669	$21,847

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 is as follows:

	Year ended December 31,					
	2006		2005		2004	
	(in thousands)					
Computed at federal statutory tax rate	$44,063	35.0%	$35,966	35.0%	$19,320	35.0%
State income taxes, net of federal income tax benefit	5,391	4.2%	4,341	4.2%	2,486	4.5%
Other, net	534	0.5%	362	0.4%	41	0.1%
Total income tax expense	$49,988	39.7%	$40,669	39.6%	$21,847	39.6%

The principal components of our net deferred income tax liability are as follows:

	December 31,	
	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Property and equipment	$187,081	$123,757
Fair value of derivative instrument	3,285	—
Other	5,119	7,638
Total deferred tax liabilities	195,485	131,395
Deferred tax assets:		
Fair value of derivative instrument	—	8,023
Deferred income—coal properties	5,331	5,939
Pension and post-retirement benefits	2,857	1,734
Net operating loss carry forwards	2,219	—
Other	6,698	4,513
Total deferred tax assets	17,105	20,209
Net deferred tax liability	$178,380	$111,186

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, 2006 and 2005, no valuation allowance has been recorded as we estimate that it is more likely than not that all of our deferred tax assets will be realized.

In June 2006, we acquired 100% of the common stock of Crow Creek (see Note 5). As a result, we acquired federal and state tax net operating loss carryforwards ("NOLs") which, if unused, will expire between 2022 and 2026. In addition to the carryforward period, these acquired NOLs are subject to other restrictions and limitations, including Internal Revenue Code, Section 382, which impact their ultimate realizability. As of December 31, 2006, we had approximately $4.4 million of federal regular tax NOLs and approximately $11.3 million of state NOLs. We did not record any valuation allowance with respect to these NOL's as we estimate that it is more likely than not that these NOLs will be utilized before they expire.

16. Employee Benefit Plans

401(k) Plan

We sponsor a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 50% of their base salaries. After the employee meets certain service requirements, we match each employee's contributions up to 6% of the employee's base salary. Our matching contributions to the 401(k) Plan were approximately $0.9 million, $0.6 million and $0.4 million for the years ended December 31, 2006, 2005 and 2004. Beginning in 2005, we had the option to make additional contributions at our discretion. We made a discretionary contribution of $0.2 million to the 401(k) Plan in 2006. We made no discretionary contributions in 2005 or 2006.

Pension Plans and Other Post-retirement Benefits

We provide post-separation ("pension") payments to certain eligible employees. Benefits are typically based on the employee's average annual compensation and service.

We also offer post-retirement healthcare benefits to employees hired prior to January 1, 1991, who retire from active service. The benefits include medical and prescription drug coverage for the retirees and dependents and life insurance for the retirees. The medical coverage is noncontributory for retirees who retired on or before December 31, 1990 and may be contributory for retirees who retired on or after January 1, 1991.

On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158. SFAS No. 158 required us to recognize the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligations) of our pension and other post-retirement benefit plans in the December 31, 2006 consolidated statement of financial position, with a corresponding adjustment to accumulated other comprehensive income ("AOCI"), net of tax. The adjustment to AOCI at adoption represents the net unrecognized actuarial losses, unrecognized prior service costs, and unrecognized transition obligation remaining from the initial adoption of SFAS No. 87, *Employers' Accounting for Pensions,* all of which were previously netted against the plans' funded status in our consolidated statements of financial position pursuant to the provisions of SFAS No. 87. These amounts will be subsequently recognized as net periodic pension cost pursuant to our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic pension cost in the same periods will be recognized as a component of other comprehensive income. Those amounts will be subsequently recognized as a component of net periodic pension cost on the same basis as the amounts recognized in AOCI at adoption of SFAS No. 158.

The incremental effects of adopting the provisions of SFAS No. 158 on our consolidated statement of financial position at December 31, 2006 are presented in the following table. The adoption of SFAS No. 158 had no effect on our consolidated statement of income for the year ended December 31, 2006, or for any prior period presented, and it will not affect our operating results in future periods. Had we not been required to adopt SFAS No. 158 at December 31, 2006, we would have recognized an additional minimum liability pursuant to the provisions of SFAS No. 87. The effect of recognizing the additional minimum liability is included in the table below in the column labeled "Prior to Adopting SFAS No. 158":

	As of December 31, 2006			
	Prior to Adopting SFAS No. 158	Effect of Adopting SFAS No. 158 for Pension Plan	Effect of Adopting SFAS No. 158 for Post-retirement Healthcare Plan	As Reported
	(in thousands)			
Other long-term assets	$ 11,935	$(14)	$ —	$ 11,921
Effect on total assets		$(14)	$ —	
Accounts payable and accrued liabilities	$154,362	$ 96	$ 251	$154,709
Other long-term liabilities	24,305	(96)	1,794	26,003
Deferred income tax liability	179,101	(5)	(716)	178,380
Accumulated other comprehensive income (loss)	(6,616)	(9)	(1,329)	(7,954)
Effect on total liabilities and shareholders' equity		$(14)	$ —	

The following table provides the amounts included in AOCI at December 31, 2006 that have not yet been recognized in net periodic pension cost:

	Unrecognized Costs As of December 31, 2006	
	Pension	Post-retirement Healthcare
	(in thousands)	
Unrecognized transition obligation	$ 3	$ —
Tax effect	(1)	—
Unrecognized transition obligation, net of tax	2	—
Unrecognized prior service costs	11	759
Tax effect	(4)	(266)
Unrecognized prior service costs, net of tax	7	493
Actuarial loss	646	1,286
Tax effect	(226)	(450)
Actuarial loss, net of tax	420	836
Total amount recognized in AOCI, net of tax	$ 429	$1,329

The following table provides a reconciliation of the beginning and ending balances of the portion of AOCI that relates to the pension and post-retirement healthcare plans:

	Pension			Post-retirement Healthcare		
	2006	2005	2004	2006	2005	2004
	(in thousands)					
Beginning balance in AOCI	$(401)	$(417)	$(375)	$ —	$—	$—
Change in minimum pension liability, before adoption of SFAS No. 158, net of tax of $10	(19)	16	(42)	—	—	—
Effect on comprehensive income	(19)	16	(42)	—	—	—
Adoption of SFAS No. 158:						
Pension prior service cost, net of tax of $4	(7)	—	—	—	—	—
Pension transition obligation, net of tax of $1	(2)	—	—	—	—	—
Post-retirement healthcare prior service cost, net of tax of $266	—	—	—	(493)	—	—
Post-retirement healthcare actuarial loss, net of tax of $450	—	—	—	(836)	—	—
Adjustment to initially apply SFAS No. 158, net of tax	(9)	—	—	(1,329)	—	—
Ending balance in AOCI	$(429)	$(401)	$(417)	$(1,329)	$—	$—

The following table provides the transition obligation, prior service cost and actuarial loss included in AOCI and expected to be recognized in net periodic pension cost during the year ending December 31, 2007:

	Costs Expected To Be Recognized For the Year Ending December 31, 2007	
	Pension	Post-retirement Healthcare
	(in thousands)	
Amortization of transition obligation	$ 3	$ —
Tax effect	(1)	—
Amortization of transition obligation, net of tax	2	—
Amortization of prior service costs	6	88
Tax effect	(2)	(31)
Amortization of prior service costs, net of tax	4	57
Amortization of actuarial loss	36	75
Tax effect	(13)	(26)
Amortization of actuarial loss, net of tax	23	49
Total amount expected to be recognized in net periodic pension cost during 2007, net of tax	$ 29	$ 106

A reconciliation of the beginning and ending balances of the benefit obligations and fair value of plan assets for the years ended December 31, 2006 and 2005, and the funded status at December 31, 2006 and 2005, is as follows:

	Pension		Post-retirement Healthcare	
	2006	2005	2006	2005
	(in thousands)			
Change in benefit obligation:				
Obligation—beginning of year	$ 2,242	$ 2,348	$ 4,571	$ 4,404
Service cost	—	—	27	29
Interest cost	127	129	243	241
Benefits paid	(232)	(241)	(426)	(461)
Actuarial loss (gain)	66	6	(113)	358
Obligation -end of year	2,203	2,242	4,302	4,571
Change in fair value of plan assets:				
Fair value-beginning of year	—	—	—	—
Employer contributions	232	241	401	438
Participant contributions	—	—	25	23
Benefit payments	(232)	(241)	(426)	(461)
Fair value-end of year	—	—	—	—
Funded status-end of year	$(2,203)	$(2,242)	$(4,302)	$(4,571)
Accumulated benefit obligation—end of year	$(2,203)	$(2,242)	$(4,302)	$(4,571)

The underfunded status of the pension and post-retirement healthcare plans of $2.2 million and $4.3 million as of December 31, 2006 has been recognized as a liability in the accompanying statements of financial position. The following table provides the amounts recognized in the statements of financial position at December 31, 2006 and 2005:

	Pension		Post-retirement Healthcare	
	2006	2005	2006	2005
	(in thousands)			
Other long-term assets	$ —	$ 24	$ —	$ —
Accounts payable and accrued liabilities	(237)	(140)	(411)	(160)
Other long-term liabilities	(1,966)	(2,102)	(3,891)	(2,058)
Deferred income tax asset	231	216	716	—
Accumulated other comprehensive loss	429	401	1,329	—

The following table provides the components of net periodic benefit cost for the plans for the years ended December 31, 2006 and 2005:

	Pension		Post-retirement Healthcare	
	2006	2005	2006	2005
	(in thousands)			
Service cost	$—	$—	$ 27	$ 29
Interest cost	127	129	243	241
Amortization of prior service cost	6	6	89	88
Amortization of transition obligation	4	3	—	—
Recognized actuarial loss	36	31	81	66
Net periodic benefit cost	$173	$169	$440	$424

We used an assumed discount rate of 5.70% in 2006 and 5.75% in 2005 for the measurement of our pension and post-retirement healthcare benefit obligations. We base the discount rate on the published Moody's Aa corporate bond yield as of the measurement date. We choose to use the Moody's Aa corporate bond yield because it is a widely available rate and its portfolio approximates the characteristics of our plans.

For measurement purposes, a 9.0% annual rate increase in the per capita cost of covered health care benefits was assumed for 2006. The rate is assumed to decrease gradually to 5% for 2013 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for post-retirement benefits. A 1% change in assumed health care cost trend rates would have the following effects for 2006 (in thousands):

	One Percent Increase	One Percent Decrease
Effect on total of service and interest cost components	$ 10	$ (10)
Effect on post-retirement benefit obligation	181	(175)

We expect to contribute $0.2 million to the pension plan and $0.4 million to the post-retirement healthcare plan in 2007.

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

	Pension	Post-retirement Healthcare
	(in thousands)	
2007	$237	$ 423
2008	239	426
2009	234	422
2010	228	420
2011	216	411
2012–2016	938	1,808

17. Earnings per Share

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the last three years:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share data)		
Net income	$75,909	$62,088	$33,355
Weighted average shares, basic	18,681	18,546	18,306
Effective of dilutive securities:			
Stock options	185	186	161
Weighted average shares, diluted	18,866	18,732	18,467
Net income per share, basic	$ 4.06	$ 3.35	$ 1.82
Net income per share, diluted	$ 4.02	$ 3.31	$ 1.81

Options with an exercise price exceeding the average price of the underlying securities are not considered to be dilutive and are not included in calculation of the denominator for diluted earnings per share for the years ended December 31, 2006 and 2005. No options outstanding at December 31, 2004 had exercise prices exceeding the average price of the underlying securities.

18. Share-Based Payments

Stock Compensation Plans

Adoption of New Accounting Standard. 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, 2006, there were approximately 204,000 and 224,000 shares available for issuance to directors and employees pursuant to the Stock Compensation Plans. Prior to January 1, 2006, we accounted for those plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations, as permitted by SFAS No. 123, *Accounting for Stock-Based Compensation*. Stock-based compensation cost in our statements of income prior to 2006 included only costs related to restricted stock and deferred common stock units. Prior to 2006, we did not recognize expense for options as permitted by SFAS No. 123 because all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the year ended December 31, 2006 includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006 based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123 and (b) compensation cost for all share-based payments granted on or after January 1, 2006 based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated. For the years ended December 31, 2006 and 2005, we recognized $2.8 million and $0.7 million of compensation expense related to the Stock Compensation Plans. Compensation expense related to the Stock Compensation Plans was not significant in 2004. The total income tax benefit recognized in our consolidated statements of income for the Stock Compensation Plans was $1.1 million and $0.3 million for the years ended December 31, 2006 and 2005.

As a result of adopting SFAS No. 123(R) on January 1, 2006, our income before minority interest and income taxes and our net income are $1.4 million and $0.8 million lower for the year ended December 31, 2006 than if we had continued to account for share-based compensation under Opinion No. 25. Basic and diluted earnings per share are $0.05 and $0.04 lower for the year ended December 31, 2006 than if we had continued to account for share-based compensation under Opinion No. 25.

Prior to the adoption of SFAS No. 123(R), we presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in our consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $2.6 million excess tax benefit classified as a financing cash inflow for the year ended December 31, 2006 would have been classified as an operating cash inflow if we had not adopted SFAS No. 123(R).

The following table illustrates the effect on net income and earnings per share as if we had applied the fair value recognition provision of SFAS No. 123 to options granted under our stock option plans for the years ended December 31, 2005 and 2004. For purposes of this pro forma disclosure, the value of the options is estimated using a Black-Scholes-Merton option-pricing formula and amortized to expense over the options' vesting periods (in thousands, except per share data).

	Year Ended December 31,	
	2005	2004
Net income, as reported	$62,088	$33,355
Add: Stock-based employee compensation expense included in reported net income related to restricted units director and director compensation, net of related tax effects	1,008	435
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(1,751)	(1,022)
Pro forma net income	$61,345	$32,768
Earnings per share		
Basic—as reported	$ 3.35	$ 1.82
Basic—pro forma	$ 3.31	$ 1.79
Diluted—as reported	$ 3.31	$ 1.81
Diluted—pro forma	$ 3.27	$ 1.77

Stock Options. The exercise price of all options granted under the Stock Compensation Plans is at 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 10 years following the grant. Options vest upon terms established by the Compensation and Benefits Committee of our Board of Directors. 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 after reaching 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.

Options granted on or before January 2, 2004 under the Stock Compensation Plans vested on the first anniversary of the date of grant. Options granted after January 2, 2004 vest ratably over a three-year period so that one-third is exercisable after one year, another third is exercisable after two years and the remaining third is exercisable after three years.

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.

	2006	2005	2004
Expected volatility	20.9% to 31.5%	26.4%	27.7%
Dividend yield	0.60% to 0.71%	0.81% to 1.10%	1.56% to 1.60%
Expected life	3.5 to 4.6 years	4 years	4 years
Risk-free interest rate	4.59% to 5.01%	3.88% to 4.04%	2.47%

The following table summarizes activity for our most recent fiscal year with respect to the common stock options awarded under the Stock Compensation Plans described above:

Options	Shares Under Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
			(in years)	(in thousands)
Outstanding at January 1, 2006	621,631	$26.68		
Granted	212,991	63.64		
Exercised	(150,301)	21.67		
Forfeit	(17,333)	52.38		
Outstanding at December 31, 2006	666,988	$38.95	7.4	$21,201
Exercisable at December 31, 2006	333,519	$23.35	6.2	$15,794

The weighted-average grant-date fair value of options granted during the years ended December 31, 2006, 2005 and 2004 was $14.34, $12.28 and $6.20 per option. The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 was $7.4 million, $3.9 million and $6.9 million.

A summary of the status of our nonvested options as of December 31, 2006, and changes during the year then ended, is presented below:

Nonvested Options	Options	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	232,937	$ 9.19
Granted	212,991	14.34
Vested	(96,827)	8.60
Forfeit	(15,632)	11.55
Nonvested at December 31, 2006	333,469	$12.54

As of December 31, 2006, we had $2.4 million of total unrecognized compensation cost related to nonvested share-based compensation arrangements granted under the Stock Compensation Plans. We expect that cost to be recognized over a weighted-average period of 1.0 year. The total fair value of shares vested during the years ended December 31, 2006, 2005 and 2004 was $0.8 million, $0.8 million and $2.1 million.

Cash received from the exercise of stock options for the year ended December 31, 2006 was $6.1 million. The actual tax benefit realized for the tax deductions from option exercises was $2.6 million for the year ended December 31, 2006.

Restricted Common Stock. Restricted stock vests upon terms established by the compensation and benefits committee. 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, disability or retirement, the grantee's restricted stock will be automatically forfeited. If a grantee's employment terminates by reason of death, disability or retirement, the grantee's restricted stock will automatically vest unless otherwise determined by the compensation and benefits committee. Except as specified by the Compensation and Benefits Committee of our Board of Directors, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock granted in 2006 and 2005 vests over a three-year period, with either one-third vesting in each year or 25% vesting after the first year, 25% vesting after the second year and 50% vesting after the third year. We recognize compensation expense on a straight-line basis over the vesting period. No restricted stock was granted prior to January 1, 2005.

A summary of the status of our nonvested restricted stock as of December 31, 2006, and changes during the year then ended, is presented below:

	Nonvested Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	27,576	$58.58
Granted	5,518	63.07
Vested	(7,554)	57.75
Nonvested at December 31, 2006	25,540	$59.80

At December 31, 2006, we had $1.2 million of total unrecognized compensation cost related to nonvested restricted stock. We expect that cost to be recognized over a weighted-average period of 0.9 years. The total grant-date fair value of restricted stock vested was $0.4 million in 2006. No restricted stock vested prior to 2006.

Deferred Common Stock Units. A portion of compensation 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 shares of common stock.

The following table summarizes activity for the most recent fiscal year with respect to deferred common units awarded:

	Deferred Common Units
Outstanding at January 1, 2006	12,824
Granted	10,670
Converted to common units	—
Outstanding at December 31, 2006	23,494

In accordance with EITF Issue No. 97-14, *Accounting for Deferred Compensation Arrangements Where Amounts Earned Are Held in a Rabbi Trust and Invested,* we recorded a $1.3 million and $0.6 million deferred compensation obligation in shareholders' equity at December 31, 2006 and 2005 and a corresponding amount for treasury stock. No deferred common stock units were granted prior to January 1, 2005.

Shareholder Rights Plan

In February 1998, our Board of Directors adopted a Shareholder Rights Plan (the "Plan") designed to prevent an acquirer from gaining control of the Company without offering a fair price to all shareholders. The Plan was amended in March 2002. Each common share outstanding has one right, and each right entitles the holder to purchase from us one one-thousandth of a share of Series A Junior Participating Preferred Stock, $100 par value, at a price of $100 subject to adjustment. The rights are not exercisable or transferable apart from the common stock until after a person or affiliated group has acquired or obtained the right to acquire 15% or more (or 10% or more if such person or group has been deemed to be an "adverse person" as defined in the Plan) of our common stock. Each right will entitle the holder, under certain circumstances, to acquire at half the value, either (i) common stock of the Company, (ii) a combination of cash, other property, or common stock or other securities of the Company, or (iii) common stock of an acquiring person. Any such event would also result in any rights owned beneficially by the acquiring person or its affiliates becoming null and void. The rights expire in February 2008 and are redeemable under certain circumstances.

PVG Long-Term Incentive Plan

The general partner of PVG has a long-term incentive plan that permits the grant of awards covering an aggregate of 300,000 PVG common units to employees and directors of PVG's general partner and employees of its affiliates who perform services for PVG. Awards under the PVG 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. As of December 31, 2006, the general partner of PVG had granted no awards under its long-term incentive plan.

PVG Common Units

We granted 39,500 PVG common units at a weighted average grant-date fair value of $18.73 per unit to our officers and employees in 2006. The PVG common units vested on the date of grant but bear a restrictive legend. We recognized compensation expense of $0.7 million in 2006 related to the grant of PVG common units.

PVR Long-Term Incentive Plan

The general partner of PVR has a long-term incentive plan that permits the grant of awards covering an aggregate of 600,000 PVR common units to employees and directors of the general partner and employees of its affiliates who perform services for PVR. Awards under the PVR long-term incentive plan can be in the form of PVR common units, PVR restricted 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. Compensation expense related to the PVR long term incentive plan totaled $1.9 million, $1.4 million and $0.4 million for the years ended December 31, 2006, 2005 and 2004.

PVR Common Units. The general partner of PVR granted 1,795 PVR common units at a weighted average grant-date fair value of $26.01 per unit to non-employee directors in 2006. The general partner of PVR granted 876 PVR common units at a weighted average grant-date fair value of $25.36 per unit to non-employee directors in 2005. The general partner of PVR granted 9,922 PVR common units at a weighted average grant-date fair value of $17.42 per unit to non-employee directors in 2004.

PVR Restricted Units. PVR restricted units vest upon terms established by the compensation and benefits committee of PVR's general partner. In addition, all PVR restricted 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 PVR restricted units will be automatically forfeited unless, and to the extent that, the compensation and benefits committee provides otherwise. Distributions payable with respect to PVR restricted units may, in the compensation and benefits 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 units granted in 2006 and 2005 vest over a three-year period, with one-third vesting in each year. Restricted units granted in 2004 vested on the first anniversary of the date of grant.

A summary of the status of nonvested PVR restricted units as of December 31, 2006, and changes during the year then ended, is presented below:

	Nonvested Restricted Units	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	113,624	$18.81
Granted	82,320	28.83
Vested	(81,116)	26.64
Forfeit	(614)	27.99
Nonvested at December 31, 2006	114,214	$20.42

At December 31, 2006, PVR had $2.2 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 0.9 years. The total grant-date fair value of restricted units vested was $2.2 million in 2006, $0.4 million in 2005 and $0.4 million in 2004.

Deferred PVR Common Units. A portion of the compensation to the non-employee directors of the general partner of PVR 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. PVR common units delivered in connection with deferred PVR common units may be PVR common units acquired by PVR's general partner in the open market, PVR common units already owned by the general partner, PVR common units acquired by PVR's general partner directly from PVR or any other person, or any combination of the foregoing. PVR's general partner is entitled to reimbursement by PVR for the cost incurred in acquiring PVR common units. Deferred PVR common units awarded to directors receive all cash or other distributions paid by PVR on account of its common units.

The following table summarizes activity for the most recent fiscal year with respect to deferred PVR common units awarded:

	Deferred Common Units
Outstanding at January 1, 2006	21,710
Granted	23,636
Converted to common units	(6,439)
Outstanding at December 31, 2006	38,907

The aggregate intrinsic value of deferred PVR common units converted to PVR common units in 2006 was $0.2 million. No deferred PVR common units converted to PVR common units in 2005 or 2004.

19. Other Comprehensive Income

Comprehensive income represents certain changes in equity during the reporting period, including net income and charges directly to equity which are excluded from net income. For the three years ended December 31, 2006, 2005 and 2004, the components of other comprehensive income were as follows:

	Cash Flow Hedges	Minimum Pension Liability	Total
		(in thousands)	
Hedging unrealized loss, net of tax of $321	$ 597	$—	$ 597
Hedging reclassification adjustment, net of tax of $335	622	—	622
Pension adjustment, net of tax of $10	—	(19)	(19)
Other comprehensive income for the year ended December 31, 2006	$ 1,219	$(19)	$ 1,200
Hedging unrealized loss, net of tax of $8,726	$(16,206)	$—	$(16,206)
Hedging reclassification adjustment, net of tax of $4,897	9,094	—	9,094
Pension plan adjustment, net of tax of $9	—	16	16
Other comprehensive income for the year ended December 31, 2005	$ (7,112)	$ 16	$ (7,096)
Hedging unrealized loss, net of tax of $1,214	$ (2,254)	$—	$ (2,254)
Hedging reclassification adjustment, net of tax $2,060	3,826	—	3,826
Pension plan adjustment, net of tax of $30	—	(42)	(42)
Other comprehensive income for the year ended December 31, 2004	$ 1,572	$(42)	$ 1,530

20. Segment Information

Segment information has been prepared in accordance with SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information.* Under SFAS No. 131, operating segments are defined as components of an enterprise 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 chief operating decision-making group consists of our Chief Executive Officer and other senior officials. This group routinely reviews and makes operating and resource allocation decisions among our oil and gas operations, PVR's coal 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.
- Coal (the "PVR coal" segment)—management and leasing of coal properties and subsequent collection of royalties; other land management activities such as selling standing timber and real estate rentals; leasing of fee-based coal-related infrastructure facilities to certain lessees and end-user industrial plants.
- Natural Gas Midstream (the "PVR midstream" segment)—natural gas processing, natural gas gathering and other related services.

The following table presents a summary of certain financial information relating to our segments:

	Oil and Gas	PVR Coal	PVR Midstream (1)	Corporate and Other	Consolidated
			(in thousands)		
As of and for the Year Ended December 31, 2006					
Revenues	$236,238	$112,981	$404,628	$ 82	$ 753,929
Intersegment revenues (2)	(282)	—	282	—	—
Operating costs and expenses	94,886	19,138	358,440	16,716	489,180
Depreciation, depletion and amortization	56,237	20,399	17,094	487	94,217
Operating income (loss)	$ 84,833	$ 73,444	$ 29,376	$(17,121)	170,532
Interest expense					(24,832)
Interest income and other					3,718
Derivatives					19,497
Income before minority interest and taxes					$ 168,915
Total assets	$885,550	$409,709	$304,314	$ 33,576	$1,633,149
Equity investments	—	25,295	60	—	25,355
Additions to property and equipment and acquisitions, net of cash acquired (3)	331,551	92,697	37,015	3,676	464,939
As of and for the Year Ended December 31, 2005					
Revenues	$226,819	$ 95,755	$350,593	$ 697	$ 673,864
Operating costs and expenses	80,669	16,121	321,509	11,826	430,125
Impairment of oil and gas properties	4,785	—	—	—	4,785
Depreciation, depletion and amortization	45,885	17,890	12,738	424	76,937
Operating income (loss)	$ 95,480	$ 61,744	$ 16,346	$(11,553)	162,017
Interest expense					(15,318)
Interest income and other					1,332
Derivatives					(14,885)
Income before minority interest and taxes					$ 133,146
Total assets	$576,634	$372,322	$285,557	$ 17,033	$1,251,546
Equity investments	—	26,612	60	—	26,672
Additions to property and equipment and acquisitions, net of cash acquired (4)	171,301	112,497	206,811	350	490,959
As of and for the Year Ended December 31, 2004					
Revenues	$151,672	$ 75,630	$ —	$ 1,123	$ 228,425
Operating costs and expenses	57,668	16,479	—	10,334	84,481
Impairment of oil and gas properties	655	—	—	—	655
Loss on assets held for sale	7,541	—	—	—	7,541
Depreciation, depletion and amortization	35,886	18,632	—	434	54,952
Operating income (loss)	$ 49,922	$ 40,519	$ —	$ (9,645)	80,796
Interest expense					(7,672)
Interest income and other					1,101
Income before minority interest and taxes					$ 74,225
Total assets	$482,343	$284,435	$ —	$ 16,557	$ 783,335
Equity investments	—	27,881	—	—	27,881
Additions to property and equipment and acquisitions, net of cash acquired (5)	123,977	2,148	—	176	126,301

(1) Represents the results of operations of the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.
(2) Represents agent fees paid by the oil and gas segment to the PVR midstream segment for marketing certain natural gas production.
(3) Oil and gas segment includes deferred tax assets of $32.3 million and acquisition of net liabilities other than property or equipment of $29.1 million related to the Crow Creek Acquisition. Coal segment includes acquisition of assets other than property or equipment of $1.2 million.
(4) Coal segment excludes noncash expenditures of $14.4 million related to acquisitions.
(5) Coal segment excludes noncash expenditures of $1.1 million related to acquisitions.

Operating income is equal to total revenues less cost of midstream gas purchased, operating costs and expenses and depreciation, depletion and amortization. Operating income does not include certain other income items, interest expense, interest income and income taxes. Identifiable assets are those assets used in our operations in each segment.

For the year ended December 31, 2006, one customer of the natural gas midstream segment accounted for $129.1 million, or 17%, of our consolidated net revenues. Intercompany railcar rental revenues were $0.8 million in 2006 and are included in the PVR coal 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. In 2006, the oil and gas segment paid $0.4 million to the PVR midstream segment for marketing a portion of the oil and gas segment's natural gas production. The marketing agreement was effective September 1, 2006.

For the year ended December 31, 2005, two customers of the natural gas midstream segment accounted for approximately $81.9 million and $77.1 million, or 12% and 11%, of consolidated net revenues. In June 2005, one of our subsidiaries began leasing railcars from a subsidiary of PVR. Railcar rental revenues were $0.4 million in 2005 and are included in the PVR coal 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.

For the year ended December 31, 2004, two customers of the oil and gas segment accounted for approximately $32.3 million and $28.2 million, or 14% and 12%, of our consolidated net revenues.

21. Commitments and Contingencies

Rental Commitments

Operating lease rental expense in the years ended December 31, 2006, 2005 and 2004 was $10.0 million, $5.8 million and $4.2 million. Minimum rental commitments for the next five years under all non-cancelable operating leases in effect at December 31, 2006 were as follows (in thousands):

2007	$ 6,449
2008	4,143
2009	1,657
2010	1,546
2011	1,515
Total minimum payments	$15,310

Our rental commitments primarily relate to equipment, building and coal reserve-based properties which PVR subleases, or intends to sublease, to third parties. The obligation 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. We believe that the future rental commitments cannot be estimated with certainty; however, based on current knowledge and historical trends, PVR believes that it will incur approximately $0.9 million in rental commitments annually until the reserves have been exhausted.

Drilling Commitments

We have agreements to purchase oil and gas well drilling services from third parties for terms ranging from two 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 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, 2006, the penalty amount would have been $17.2 million if we had terminated our agreements on that date. Management intends to utilize drilling services under these agreements for the full terms and has no plans to terminate the agreements early. Our obligation for drilling commitments in effect at December 31, 2006 for the next five years and thereafter is as follows (in thousands):

2007	$10,875
2008	8,395
2009	8,395
Total drilling commitments	$27,665

Firm Transportation Commitments

In 2004, we entered into contracts which provide firm transportation capacity rights for specified volumes per day on a pipeline system for terms ranging 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. Our obligation for firm transportation commitments in effect at December 31, 2006 for the next five years and thereafter is as follows (in thousands):

2007	$1,885
2008	1,160
2009	1,081
2010	1,081
2011	1,081
Thereafter	3,153
Total firm transportation commitments	$9,441

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, management believes these claims will not have a material effect on the financial position, liquidity or 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 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.

The operations of PVR's coal lessees and natural gas midstream segment 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 for all environmental and reclamation liabilities arising under those laws and regulations on the relevant lessees. The lessees are bonded and have indemnified PVR against any and all future environmental liabilities. PVR regularly visits coal properties under lease to monitor lessee compliance with environmental laws and regulations and to review mining activities. Management believes that the operations of PVR's coal lessees and natural gas midstream segment will comply with existing regulations and does not expect any material impact on its financial condition or results of operations.

As of December 31, 2006 and 2005, PVR's environmental liabilities included $1.6 million and $2.5 million, which represents our best estimate of the liabilities as of those dates related to the coal and natural gas midstream businesses. PVR has reclamation bonding requirements with respect to certain unleased and inactive properties. Given the uncertainty of when the 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.

22. Quarterly Financial Information (Unaudited)

Summarized Quarterly Financial Data

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except share data)			
2006				
Revenues	$200,907	$179,150	$188,393	$185,479
Operating income	$ 48,666	$ 49,939	$ 44,644	$ 27,283
Net income	$ 24,108	$ 18,217	$ 22,881	$ 10,703
Net income per share (1):				
Basic	$ 1.29	$ 0.98	$ 1.22	$ 0.57
Diluted	$ 1.28	$ 0.96	$ 1.21	$ 0.57
Weighted average shares outstanding:				
Basic	18,652	18,677	18,679	18,746
Diluted	18,873	18,913	18,895	18,936
2005 (2)				
Revenues	$ 88,210	$157,965	$186,965	$241,296
Operating income	$ 27,704	$ 26,417	$ 46,808	$ 61,088
Net income	$ 7,040	$ 7,647	$ 19,990	$ 27,411
Net income per share (1):				
Basic	$ 0.38	$ 0.41	$ 1.08	$ 1.47
Diluted	$ 0.38	$ 0.41	$ 1.07	$ 1.46
Weighted average shares outstanding:				
Basic	18,490	18,517	18,560	18,613
Diluted	18,694	18,719	18,760	18,818

(1) The sum of the quarters may not equal the total of the respective year's net income per share due to changes in the weighted average shares outstanding throughout the year.

(2) Includes the results of operations from the natural gas midstream segment since March 3, 2005, the closing date of the Cantera Acquisition.

23. 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 Securities and Exchange Commission ("SEC") and SFAS No. 69, *Disclosures about Oil and Gas Producing Activities.* The amounts shown include our net working and royalty interest in all of our oil and gas operations.

Capitalized Costs Relating to Oil and Gas Producing Activities

	December 31,		
	2006	2005	2004
		(in thousands)	
Proved properties	$ 213,017	$ 126,286	$ 120,742
Unproved properties	100,008	66,727	61,013
Wells, equipment and facilities	706,860	502,877	392,230
Support equipment	2,713	4,088	3,461
	1,022,598	699,978	577,446
Accumulated depreciation and depletion	(245,463)	(191,860)	(148,212)
Net capitalized costs (1)	$ 777,135	$ 508,118	$ 429,234

(1) Net capitalized costs of $19.9 million at December 31, 2006, $16.4 million at December 31, 2005, and $13.7 million at December 31, 2004, relating to a transmission pipeline and compression in the Appalachian Basin placed into service from 2004 to 2006 were excluded from net capitalized costs.

In accordance with SFAS No. 143, during 2006, 2005 and 2004, an additional $1.4 million, $0.4 million and $0.3 million were added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	December 31,		
	2006	2005	2004
		(in thousands)	
Proved property acquisition costs	$ 72,724	$ —	$ —
Unproved property acquisition costs	56,563	26,360	13,046
Exploration costs	51,665	30,335	26,429
Development costs and other (1)	184,675	109,066	82,048
Total costs incurred	$365,627	$165,761	$121,523

(1) Development costs of $5.1 million in 2006, $3.8 million in 2005 and $13.7 million in 2004 relating to a transmission pipeline and compression in the Appalachian Basin placed into service during from 2004 to 2006 were excluded from costs incurred.

Costs for the year ended December 31, 2006 include deferred income taxes of $32.3 million provided for the book versus tax basis difference related to the acquired Crow Creek properties.

Results of Operations for Oil and Gas Producing Activities

The following schedule 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.

	December 31,		
	2006	2005	2004
		(in thousands)	
Revenues	$234,156	$226,219	$151,786
Production expenses	39,681	30,940	23,728
Exploration expenses	34,330	40,917	26,058
Depreciation and depletion expense (1)	55,252	44,865	35,772
Impairment of oil and gas properties	8,517	4,785	655
	96,376	104,712	65,573
Income tax expense	38,165	41,466	25,967
Results of operations	$ 58,211	$ 63,246	$ 39,606

(1) Depreciation expense of $1.0 million in 2006, $0.9 million in 2005 and $0.1 million in 2004 relating to a transmission pipeline and compression in the Appalachian Basin placed into service from 2004 to 2006 were excluded from depreciation and depletion expense.

In accordance with SFAS No. 143, the combined depletion and accretion expense related to asset retirement obligations that were recognized during 2006, 2005 and 2004 in depreciation, depletion and amortization expense was approximately $0.2 million, $0.2 million and $0.5 million.

Oil and Gas Reserves

The following schedule presents the estimated oil and gas reserves owned by us. This information includes our 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, 2005, were estimated by Wright and Company, Inc. 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 oil and gas 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 reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with equipment and operating methods.

Net quantities of proved reserves and proved developed reserves during the periods indicated are set forth in the tables below:

Proved Developed and Undeveloped Reserves	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total Equivalents (MMcfe)
December 31, 2003	6,634	283,069	322,873
Revisions of previous estimates	(418)	(13,669)	(16,177)
Extensions, discoveries and other additions	532	70,010	73,202
Production	(396)	(22,079)	(24,455)
Purchase of reserves	—	—	—
Sale of reserves in place	(9)	(1,279)	(1,333)
December 31, 2004	6,343	316,052	354,110
Revisions of previous estimates	(35)	(13,859)	(14,071)
Extensions, discoveries and other additions	554	87,860	91,184
Production	(306)	(25,676)	(27,515)
Purchase of reserves	—	—	—
Sale of reserves in place	(3,659)	(5,196)	(27,148)
December 31, 2005	2,897	359,181	376,560
Revisions of previous estimates	396	(10,182)	(7,807)
Extensions, discoveries and other additions	597	97,286	100,867
Production	(382)	(28,967)	(31,260)
Purchase of reserves	1,402	39,928	48,346
Sale of reserves in place	—	—	—
December 31, 2006	4,910	457,246	486,706
Proved Developed Reserves:			
December 31, 2004	2,895	243,480	260,850
December 31, 2005	2,017	266,970	279,070
December 31, 2006	3,049	326,480	344,775

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and gas reserves. Future cash inflows were computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas 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 oil and gas 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,		
	2006	2005	2004
		(in thousands)	
Future cash inflows	$2,848,046	$ 3,902,546	$2,310,163
Future production costs	(775,561)	(637,907)	(460,729)
Future development costs	(321,338)	(192,938)	(123,928)
Future net cash flows before income tax	1,751,147	3,071,701	1,725,506
Future income tax expense	(435,299)	(834,774)	(455,328)
Future net cash flows	1,315,848	2,236,927	1,270,178
10% annual discount for estimated timing of cash flows	(711,248)	(1,200,481)	(680,525)
Standardized measure of discounted future net cash flows	$ 604,600	$ 1,036,446	$ 589,653

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year ended December 31,		
	2006	2005	2004
Sales of oil and gas, net of productions costs	$ (196,284)	$ (236,809)	$(128,058)
Net changes in prices and production costs	(720,914)	516,662	46,269
Extensions, discoveries and other additions	142,007	327,287	177,914
Development costs incurred during the period	50,629	25,725	14,705
Revisions of previous quantity estimates	(24,460)	(54,479)	(38,771)
Purchase of minerals-in-place	51,810	—	—
Sale of minerals-in-place	—	(59,864)	(3,722)
Accretion of discount	141,165	79,459	69,585
Net change in income taxes	192,370	(170,261)	(20,779)
Other changes	(68,169)	19,073	(39,182)
Net increase (decrease)	(431,846)	446,793	77,961
Beginning of year	1,036,446	589,653	511,692
End of year	$ 604,600	$1,036,446	$ 589,653

As required by SFAS No. 69, 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 prices in effect at the end of the period. 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 the disclosure of "Costs Incurred in Certain Oil and Gas Activities" earlier in this Note and the statements of cash flows in the consolidated financial statements.

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, 2006. 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, 2006, 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, 2006. 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, 2006, our internal control over financial reporting was effective. KPMG LLP, an independent registered public accounting firm, has issued an attestation report on our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, which is included in Item 8 of this Annual Report on Form 10-K.

(c) 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 2006 which we did not disclose.

PART III

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

Except for information concerning our executive officers included Item 1 hereof, 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 Financial Statements on page 70 of this Annual Report on Form 10-K.

(2) All schedules are omitted because they are not required, inapplicable or the information is included in the consolidated financial statements or the notes thereto.

(3) Exhibits

(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).

(3.2) 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).

(3.3) 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).

(3.4) Amended and Restated Bylaws of Registrant (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on February 26, 2007).

(4.1) Rights Agreement dated as of February 11, 1998 between Penn Virginia Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 1.1 to Registrant's Registration Statement on Form 8-A filed on February 20, 1998).

(4.2) Amendment No. 1 to Rights Agreement dated as of March 27, 2002 by and between Penn Virginia Corporation and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on March 28, 2002).

(10.1) Amended and Restated Credit Agreement dated as of December 4, 2003 among Penn Virginia Corporation, the lenders party thereto, Bank One, NA, as Administrative Agent, Wachovia Bank, National Association, as Syndication Agent, Royal Bank of Canada, BNP Paribas and Fleet National Bank, as Documentation Agents, and Banc One Capital Markets, Inc. and Wachovia Capital Markets, LLC, as Co-Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2003).

(10.2) First Amendment to Amended and Restated Credit Agreement dated as of December 29, 2004 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).

(10.3) Second Amendment to Amended and Restated Credit Agreement dated as of December 15, 2005 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).

(10.4) Third Amendment to Amended and Restated Credit Agreement dated as of April 14, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006).

(10.5) Fourth Amendment to Amended and Restated Credit Agreement dated as of August 25, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.6) Fifth Amendment to Amended and Restated Credit Agreement dated as of November 1, 2006 among Penn Virginia Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2006).

(10.7) 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).

(10.8) 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).

(10.9) Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan, as amended (incorporated by reference to Exhibit 10.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2001).*

(10.10) Penn Virginia Corporation Supplemental Employees Retirement Plan, as amended (incorporated by reference to Exhibit 10.7 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).*

(10.11) Penn Virginia Corporation Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.8 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2005).*

(10.12) Penn Virginia Corporation 1994 Stock Option Plan, as amended (incorporated by reference to Exhibit 10.5 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).*

(10.13) Penn Virginia Corporation 1995 Fourth Amended and Restated Directors' Stock Compensation Plan (incorporated by reference to Exhibit 10.3 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.14) Penn Virginia Corporation Second 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 27, 2006).*

(10.15) Form of restricted stock award agreement (incorporated by reference to Exhibit 10.13 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.16) Form of deferred common stock award agreement (incorporated by reference to Exhibit 10.14 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2004).*

(10.17) Executive Change of Control Severance Agreement dated February 28, 2006 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 March 2, 2006).*

(10.18) Executive Change of Control Severance Agreement dated February 28, 2006 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 March 2, 2006).*

(10.19) Executive Change of Control Severance Agreement dated February 28, 2006 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 March 2, 2006).*

(10.20) Executive Change of Control Severance Agreement dated February 28, 2006 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 10-Q filed on March 2, 2006).*

(10.21) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Keith D. Horton (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

(10.22) Executive Change of Control Severance Agreement dated March 9, 2006 between Penn Virginia Resource GP, LLC and Ronald K. Page (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on March 14, 2006).*

(12.1) Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.

(21.1) Subsidiaries of Registrant.

(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.

---

* 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

	By: /s/ FRANK A. PICI
March 1, 2007	**Frank A. Pici** **Executive Vice President and Chief Financial Officer**
	By: /s/ FORREST W. MCNAIR
March 1, 2007	**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, 2007
/s/ JOE N. AVERETT, JR. **(Joe N. Averett, Jr.)**	Director	March 1, 2007
/s/ EDWARD B. CLOUES, II **(Edward B. Cloues, II)**	Director	March 1, 2007
/s/ A. JAMES DEARLOVE **(A. James Dearlove)**	Director and President and Chief Executive Officer	March 1, 2007
/s/ KEITH D. HORTON **(Keith D. Horton)**	Director and Executive Vice President	March 1, 2007
/s/ STEVEN W. KRABLIN **(Steven W. Krablin)**	Director	March 1, 2007
/s/ MARSHA R. PERELMAN **(Marsha R. Perelman)**	Director	March 1, 2007
/s/ PHILIPPE VAN MARCKE DE LUMMEN **(Philippe van Marcke de Lummen)**	Director	March 1, 2007
/s/ GARY K. WRIGHT **(Gary K. Wright)**	Director	March 1, 2007

[THIS PAGE INTENTIONALLY LEFT BLANK]

▷ Corporate Information

PHOTO LEFT TO RIGHT BACK ROW:
Joe N. Averett, Jr., Edward B. Cloues, II, Gary K. Wright, Keith D. Horton, Steven W. Krablin

SEATED:
A. James Dearlove, Robert Garrett, Marsha R. Perelman

NOT PICTURED:
Philippe van Marcke de Lummen

Directors

Robert Garrett [1,2]
Chairman of the Board; Director of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P. and Founder and Managing Director of AdMedia Partners, Inc.

Joe N. Averett, Jr.
Former President, CEO and Director, Crystal Gas Storage, Inc.

Edward B. Cloues, II [2,3]
Chairman and Chief Executive Officer of K-Tron International, Inc. and 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 and Chief Executive Officer and President of PVG GP, LLC, general partner of Penn Virginia GP Holdings, L.P. and Chairman and Chief Executive Officer of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Keith D. Horton
Executive Vice President and Co-President and Chief Operating Officer—Coal of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Steven W. Krablin [1,3]
Former Senior Vice President and Chief Financial Officer, National Oilwell, Inc.

Marsha Reines Perelman [1,3]
Founder and Chief Executive Officer of Woodforde Management, Inc. and Director of Penn Virginia Resource GP, LLC, general partner of Penn Virginia Resource Partners, L.P.

Philippe van Marcke de Lummen [1]
Advisor to Cheniere Energy, Inc., and former President and Chief Executive Officer of Tractebel LNG Ltd.

Gary K. Wright [2,3]
Former President, LNB Energy Advisors, former Southwest Managing Director for Chase Manhattan Bank Global Oil and Gas Group and 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

Keith D. Horton
Executive Vice President

Nancy M. Snyder
Executive Vice President, General Counsel and Corporate Secretary

Ronald K. Page
Vice President

Forrest W. McNair
Vice President and Controller

Dana G Wright
Vice President, Business Planning

Steven A. Hartman
Vice President and Treasurer

Annual Meeting

Penn Virginia Corporation's Annual Meeting will be held
10 a.m. May 8, 2007
Marriott Philadelphia West
111 Crawford Avenue
West Conshohocken, PA 19428
(610) 941-5600 phone
(610) 941-1060 fax

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

Certifications

In 2006, we submitted our Section 303A. 12(a) chief executive officer certification to the New York Stock Exchange. We have also filed with the Securities and Exchange Commission, as an exhibit to our most recently filed Annual Report on Form 10-K, the Sarbanes-Oxley Act Section 302 certifications.

(1) Member of the Nominating and Governance Committee
(2) Member of the Compensation and Benefits Committee
(3) Member of the Audit Committee

Penn Virginia Corporation

Three Radnor Corporate Center
Suite 300
100 Matsonford Road
Radnor, PA 19087
(610) 687-8900 phone
(610) 687-3688 fax
www.pennvirginia.com