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, 2010

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)**

Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

The aggregate market value of common stock held by non-affiliates of the registrant was $905,899,755 as of June 30, 2010 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 18, 2011, 45,594,907 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 4, 2011, is incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2010

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Forward-Looking Statements

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

- the volatility of commodity prices for natural gas, natural gas liquids (“NGLs”) and oil;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of natural gas, NGLs and oil;
- reductions in the borrowing base under our revolving credit facility (“Revolver”);
- our ability to contract for drilling rigs, supplies and services at reasonable costs;
- our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell the production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and gas reserves;
- drilling and operating risks;
- our ability to compete effectively against other independent and major oil and natural gas companies;
- uncertainties related to expected benefits from acquisitions of oil and natural gas properties;
- environmental liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key technical employees;
- counterparty risk related to their ability to meet their future obligations;
- changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters;
- uncertainties relating to general domestic and international economic and political conditions; and
- other risks set forth in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2010.

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

Part I

Item 1 *Business*

General

Penn Virginia Corporation (NYSE: PVA), a Virginia corporation formed in 1882, is an independent oil and gas company engaged primarily in the exploration, development and production of natural gas and oil in various domestic onshore regions of the United States including Texas, Appalachia, the Mid-Continent and Mississippi.

Prior to June 2010, we indirectly owned partner interests in Penn Virginia Resource Partners, L.P., or PVR, a publicly traded limited partnership formed by us in 2001 that is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR were held principally through our general and limited partner interests in Penn Virginia GP Holdings, L.P., or PVG, a publicly traded limited partnership formed by us in 2006. On June 7, 2010, we disposed of our remaining ownership interests in PVG and, indirectly, our interests in PVR. This divestiture completed the process of our transformation into a "pure play" exploration and production (E&P) company.

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

Description of Business

Business Overview

The year 2010 was transformational for us. We transitioned to a "pure play" E&P company, and we began, and are continuing, to refocus our operations to drill in economically attractive natural gas, oil and NGL-rich areas. To this end, we disposed of our Gulf Coast assets and exited this area, invested over $150 million to increase our leaseholds in potentially higher return prospects in the Mid-Continent and the Marcellus Shale and to establish a position in the oil rich Eagle Ford Shale. We have also suspended drilling on our acreage located in east Texas and Mississippi, which is primarily lower return, dry gas and held by production, with the option to resume drilling there when natural gas prices justify renewed investment.

As of December 31, 2010, we had proved natural gas and oil reserves of approximately 942 Bcfe, of which 79% were natural gas and 53% were proved developed. Our operations include both conventional and unconventional developmental drilling opportunities, as well as some exploratory prospects. We believe our emerging presence in several key plays, as discussed below, positions us for meaningful growth over the next several years.

As of December 31, 2010, our proved reserves and primary development plays were located in somewhat longer-lived, lower-risk core basins in Texas, Appalachia, the Mid-Continent and Mississippi, which comprised 48%, 13%, 20% and 19%, respectively, of our total proved reserves. In 2010, we produced 47.2 Bcfe, compared to 51.0 Bcfe in 2009 primarily reflecting the sale of our Gulf Coast properties in the first quarter of the year. Texas, Appalachia, the Mid-Continent, Mississippi and the Gulf Coast comprised 29%, 22%, 32%, 16% and 1% of total production volumes during 2010. In the three years ended December 31, 2010, we drilled 386 gross (244.7 net) wells, of which 92% were successful in producing natural gas, oil and NGLs in commercial quantities. For a more detailed discussion of our reserves and production, see Item 2, "Properties."

We have grown our reserves and production primarily through development and exploratory drilling, complemented to a lesser extent by making strategic acquisitions. During 2010, we replaced approximately 260% of our 2010 production by adding net proved reserves of approximately 122 Bcfe from extensions, discoveries, additions and purchases of reserves, net of other revisions. In 2010, our capital expenditures were $451.2 million, of which $243.4 million, or 54%, was related to development drilling and $140.5 million, or 31%, was related to leasehold acquisitions. The remaining $67.3 million, or 15%, was related to exploration drilling, pipelines, gathering and facilities.

As of December 31, 2010, we owned 1.2 million net acres of leasehold interests, approximately 26% of which were undeveloped. Many of our proved undeveloped locations and additional potential drilling locations are direct offsets or extensions from existing production. We believe our existing undeveloped acreage position represents over 10 years of drilling opportunities based on our historical drilling rate.

Business Strategy

We intend to pursue the following business strategies:

- *Focus on higher margin natural gas, oil and NGLs development projects given current prices for natural gas and oil.* We plan to continue to increase drilling in the higher margin prospects in the Mid-Continent and Marcellus and Eagle Ford Shales. This strategy reflects the ongoing weakness in natural gas prices and relative strength in oil and NGL prices. In 2010, approximately 18% of our total production consisted of oil and NGLs. In 2011, we anticipate 25 to 30% of our total production will be oil and NGLs.

- *Grow primarily through horizontal development drilling which we believe maximizes reserve additions, production rates and rates of return.* We anticipate spending approximately $320 million on oil and gas capital expenditures in 2011. We plan to allocate up to $225 million, or approximately 70%, of this amount to development drilling and related projects in our three focus areas of the Eagle Ford and Marcellus Shales and the Mid-Continent. We are applying horizontal drilling technology in each of these core areas.

- *Use exploratory drilling to provide operational balance and future development growth opportunities*. We anticipate allocating up to $65 million, or approximately 20%, of our 2011 oil and gas capital expenditures to our exploratory drilling activities. We plan to concentrate our exploration efforts around our three focus areas mentioned above.

- *Pursue selective leasehold and producing property acquisition opportunities in our core areas.* Our experienced team of management and technical professionals looks for opportunities to extend our leasehold acreage, especially in our focus areas. Adding acreage to our leasehold position increases the number of drilling prospects necessary to continue to grow our reserves and production. We anticipate allocating up to $30 million, or approximately 10%, of our 2011 oil and gas capital expenditures to leasehold acquisitions.

- *Redeploy cash raised from the sale of non-core assets into our focus areas.* In 2010, we realized net proceeds of $365 million through the sale of certain non-core assets, including our remaining interests in PVG. We reinvested a significant portion of these net proceeds in 2010 to expand our focus areas, and expect to use our remaining proceeds in a similar fashion.

- *Manage risk exposure through an active hedging program*. We actively manage our exposure to commodity price fluctuations by hedging the commodity price risk for our expected production through the use of derivatives, typically costless collar and swap contracts. The level of our hedging activity and duration of the instruments employed depend upon our cash flow at risk, available hedge prices and our operating strategy. For 2011, we have hedged approximately 50% of our estimated natural gas production, at average floor and ceiling prices of $5.28 and $6.65 per MMBtu, respectively.

- *Manage cash liquidity and balance sheet debt levels.* We expect to continue to use our substantial cash flow to fund the majority of our capital requirements, including working capital, supplemented as needed by debt financing, equity issuances and the sale of non-core assets, while maintaining a conservative capital structure.

Contracts

Transportation

We have entered into contracts which provide firm transportation capacity rights for specified volumes per day on various pipeline systems 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 short-term fixed price physical and spot market contracts. For the year ended December 31, 2010, approximately 59% of our consolidated product revenues resulted from four of our customers, Connect Energy Services, LLC, a subsidiary of PVR, Chesapeake Operating, Inc., Enogex, LLC and Dominion Field Services, Inc.

Commodity Derivative Contracts

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

The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. The counterparty to a swap contract is required to make a payment to us if the settlement price for any settlement period is greater than the swap price for such contracts, and we are required to make a payment to the counterparty if the settlement price is less than the swap price for such contract.

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

Competition

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 and our ability to select, acquire and develop properties. 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, geophysicists, engineers and other specialists. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. We also compete with substantially larger 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.

Government Regulation and Environmental Matters

Our operations are subject to stringent and extensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. Compliance with these laws and regulations increases our cost of doing business. Also, environmental laws and regulations have been subject to frequent changes over the years and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the “Superfund” law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a “hazardous substance” into the environment. Such “responsible persons” may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of oil and natural gas for a number of years. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been released on them may be subject to CERCLA, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and clean up of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of the RCRA. While there is currently an exclusion from the RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or natural gas, it is possible that some of these wastes could be classified as hazardous waste in the future, and therefore be subject to the RCRA.

Oil Pollution Act. The Oil Pollution Act of 1990, as amended, or OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term “waters of the United States” has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA subjects owners of facilities to strict, joint and several liability for all containment and clean up costs and certain other damages arising from a spill.

Clean Water Act. The Federal Water Pollution Control Act, or Clean Water Act, governs the discharge of certain pollutants into waters of the United States. The discharge of pollutants into regulated waters without a permit issued by the EPA or the state is prohibited. The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Safe Drinking Water Act. The Safe Drinking Water Act, or SDWA, and the Underground Injection Control Program promulgated under the SDWA, establishes the requirements for salt water disposal well activities and prohibits the migration of fluid containing contaminants into underground sources of drinking water. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Granite Wash, Eagle Ford Shale, Haynesville Shale and the Marcellus Shale formations. The U.S. Congress is currently considering legislation to amend the SDWA to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing, delaying the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse environmental impacts of hydraulic fracturing, including on water quality and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. The initial EPA study results are expected to be available in late 2012. Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as recent incidents involving the release of natural gas and fluids as a result of drilling activities in the Marcellus Shale, there have been a variety of regulatory initiatives at both the federal and state levels to restrict oil and gas drilling operations in certain locations. For example, the Governor of Pennsylvania has instituted a moratorium on leasing forest land for gas drilling. Additionally, the New York State Department of Environmental Conservation has ceased issuing exploration and production drilling permits, pending completion of an environmental impact statement regarding hydraulic fracturing. We use hydraulic fracturing extensively and any increased federal, state or local regulation of hydraulic fracturing, including legislation and regulation in Pennsylvania, could reduce the volumes of oil and natural gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. For example, the Texas Commission on Environmental Quality ("TCEQ") and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. These initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state and federal levels. Additionally, EPA has committed, pursuant to the terms of a federal Consent Decree, to evaluate the need for new or revised New Source Performance Standards for Crude Oil and Natural Gas Production facilities, along with National Emission Standards for Hazardous Air Pollutants and Residual Risk Standards for Oil and Natural Gas Production and Natural Gas Transmission and Storage facilities. If the EPA chooses to issue new standards it must finalize them by November 30, 2011.

Greenhouse Gas Emissions. There is increasing attention in the United States and worldwide being paid to the issue of climate change and the contributing effect of greenhouse gas, or GHG, emissions. On September 22, 2009, the EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule, or Reporting Rule, which was subsequently amended on July 20, 2010. The Reporting Rule establishes a new comprehensive scheme, beginning in 2011, requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. On November 9, 2010, the EPA issued final rules applying these regulations to the oil and gas source category including oil and natural gas production facilities, natural gas processing, transmission, distribution and storage facilities. In addition, on December 15, 2009, the EPA published a Final Rule, also known as the EPA's Endangerment Finding, finding that current and projected concentrations of six key GHGs in the atmosphere threaten the environment and public health and the welfare of current and future generations. Following issuance of the Endangerment Finding, the EPA promulgated final motor vehicle GHG emission standards under the Clean Air Act on April 1, 2010 that will require reduction in emissions of GHGs from motor vehicles beginning in 2011, the effect of which could reduce demand for motor fuels refined from crude oil. Also, on May 13, 2010, the EPA issued a prepublication version of a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions, to be phased in through a multistep process, with the largest sources being subject to permitting first. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. In November 2010, the EPA issued guidance on GHG best available control technology that will assist the various agencies in making these determinations.

The U.S. Congress is currently considering a number of legislative proposals to restrict GHG emissions and more than 20 states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on 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 maintenance of information about hazardous materials used or produced in operations and provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species.

Employees and Labor Relations

We and our subsidiaries had a total of 202 employees as of December 31, 2010. We consider our current employee relations to be favorable.

Common Abbreviations and Definitions

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

Bbl	a standard barrel of 42 U.S. gallons liquid volume
Bcf	One billion cubic feet
Bcfe	one billion cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
Developed acreage	lease acreage that is allocated or assignable to producing wells or wells capable of production
Development well	a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive
Dry hole	a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well
Exploratory or exploration well	a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir
GAAP	accounting principles generally accepted in the Unites States of America
Gross acre or well	an acre or well in which a working interest is owned
MBbl	one thousand barrels
Mcf	one thousand cubic feet
Mcfe	one thousand cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
MMBbl	one million barrels
MMBtu	one million British thermal units, a measure of energy content
MMcf	one million cubic feet
MMcfe	one million cubic feet equivalent with one barrel of oil or condensate converted to six thousand cubic feet of natural gas based on the estimated relative energy content
Net acre or well	gross acres or wells multiplied by the owned working interest in those gross acres or wells
NGL	natural gas liquid
NYMEX	New York Mercantile Exchange
Present value of proved reserves	the present value (discounted at 10%) of estimated future cash flows from proved oil and natural gas reserves, as estimated by our independent engineers, reduced by additional estimated future operating expenses, development expenditures and abandonment costs (net of salvage value) associated therewith (before income taxes)
Productive wells	wells that are producing oil or gas or that are capable of commercial production
Proved reserves	those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate
Proved developed reserves	proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well

Proved undeveloped reserves	proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.
Standardized measure	present value of proved reserves further reduced by the present value (discounted at 10%) of estimated future income taxes on cash flows using the average prices during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated future costs as of that fiscal year end. Prices are held constant throughout the life of the properties except where SEC guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.
Undeveloped acreage	lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated net proved reserves
Working interest	a cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease

Available Information

Our internet address is http://www.pennvirginia.com. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. All references in this Annual Report on Form 10-K to the “NYSE” refer to the New York Stock Exchange, and all references to the “SEC” refer to the Securities and Exchange Commission.

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.

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

- domestic and foreign supplies of oil, natural gas and NGLs;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of and demand for, 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 flows and borrowing capacity and possible asset impairment), the quantities of natural gas and crude oil reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

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

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

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

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

We make, and will continue to make, substantial capital expenditures to find, acquire, develop, exploit and produce oil and natural gas reserves. In 2011, we anticipate making capital expenditures, excluding acquisitions, of approximately $320 million.

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 have borrowing capacity under the Revolver, or we can raise additional funds through debt or equity financing.

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

If our revenues were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through the Revolver, or otherwise on acceptable terms, 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;
- costs of, or shortages or delays in the availability of, drilling rigs, equipment and materials;
- shortages in experienced labor;
- failure to secure necessary regulatory approvals and permits;
- title problems;
- 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.

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

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

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

We are subject to risk from loss resulting from our customers' and joint interest partners' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues. In 2010, 59% of our total consolidated product revenues resulted from four of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

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

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

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

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

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

Our business depends on transportation facilities owned by others.

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

Estimates of oil and natural gas reserves are not precise.

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

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, 2010, approximately 47% of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

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

We may record impairment losses on our oil and gas properties.

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

GAAP requires that the carrying value of oil and gas properties be reviewed on a periodic basis for possible impairment. An impairment charge is recognized when the carrying value of oil and gas properties is greater than the undiscounted future net cash flows attributable to the property. In addition to revisions to reserves and the impact of lower commodity prices, impairments may occur due to increases in estimated operating and development costs. During the past several years, we have been required to impair certain of our oil and gas properties and related assets. If natural gas, crude oil and NGL prices decline or we drill uneconomic wells, it is reasonably possible that we will have to record a significant impairment in the future. While an impairment charge reflects our ability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

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

In 2010, other companies operated approximately 27% of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator’s expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

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

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

Our producing property acquisitions carry significant risks.

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

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

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

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

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

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

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

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

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

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

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, was signed into law on July 21, 2010 and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

Legislation has been proposed in the U.S. Congress that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, the repeal of the percentage depletion allowance for oil and natural gas properties, the elimination of current deductions for intangible drilling and development costs, the elimination of the deduction for certain domestic production activities and an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on us.

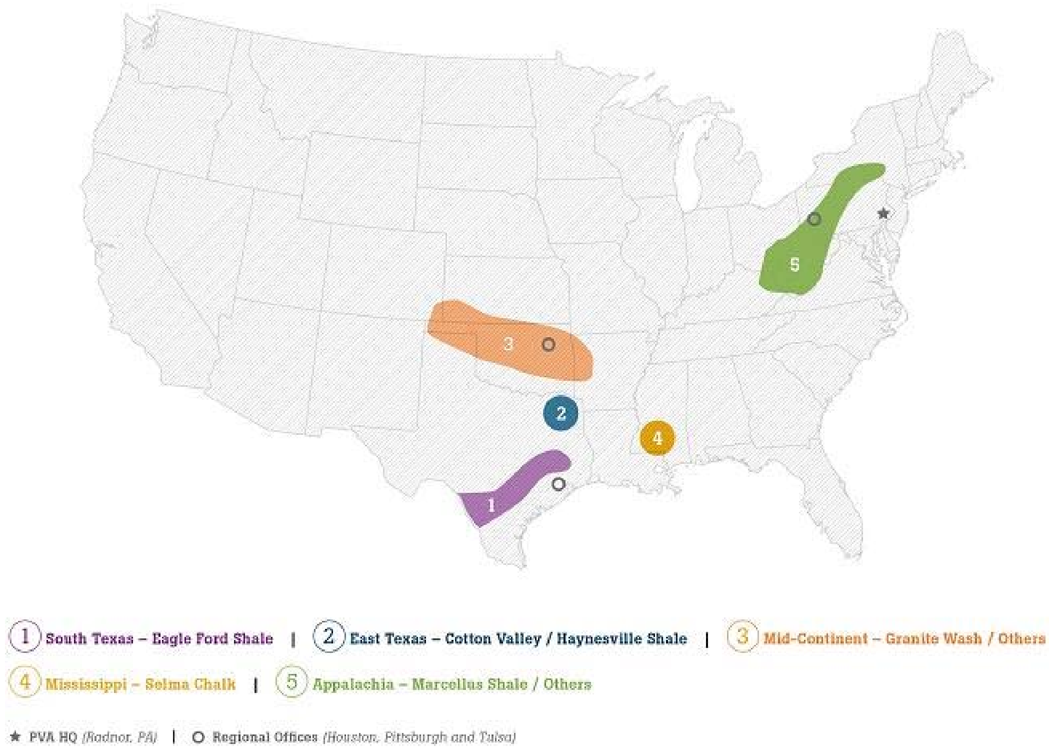
Item 1B ***Unresolved Staff Comments***

We have received no written SEC staff comments regarding our periodic or current reports under the Exchange Act which were issued 180 days or more preceding the end of our 2010 fiscal year that remain unresolved.

Item 2 ***Properties***

Title to Properties

The following map shows the general locations of our oil and gas production and exploration and related infrastructure investments as of December 31, 2010:



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

Facilities

We are headquartered in Radnor, Pennsylvania, with regional offices in Tulsa, Oklahoma; Pittsburgh, Pennsylvania; and Houston, Texas. We also have regional operations facilities at various locations in Mississippi, Oklahoma, Pennsylvania, Texas and West Virginia. All of our office facilities are leased with the exception of our operations facility in West Virginia. We believe that our facilities are adequate for our current needs.

Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we obtain or review title opinions on all material leases. However, as is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and to acquire undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are 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. Our oil and gas properties are subject to customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties.

Proved Reserves

The following table presents certain information regarding our proved reserves as of December 31, 2010, 2009 and 2008. The proved reserve estimates presented below were prepared by Wright & Company, Inc., independent petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited) in the Notes to the Consolidated Financial Statements and the report of Wright & Company, Inc., which is included as an Exhibit to this Annual Report on Form 10-K. We did not file any reports during the year ended December 31, 2010 with any federal authority or agency with respect to our estimate of oil and gas reserves.

	Natural Gas	Oil and Condensate	Natural Gas Equivalents	Standardized Measure [1]	Price Measurement Used [2]	
	(Bcf)	(MMBbl)	(Bcfe)	$ in millions	$/MMBtu	$/Bbl
2010						
Developed	413	14.8	502	$ 574		
Undeveloped [3]	332	18.0	440	67		
	745	32.8	942	$ 641	$ 4.38	$ 79.43
2009						
Developed	388	8.4	439	$ 425		
Undeveloped	389	18.0	496	100		
	777	26.4	935	$ 525	$ 3.87	$ 61.18
2008						
Developed	411	9.9	470	$ 692		
Undeveloped	343	17.1	446	37		
	754	27.0	916	$ 729	$ 5.71	$ 44.60

[1] The standardized measure considers average prices for the years ended December 31, 2010 and 2009, respectively, and prices in effect at year-end for the year ended December 31, 2008.

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

[3] The proved undeveloped reserves included in our current estimates relate to wells that are forecasted to be drilled within the next five years.

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 commodity prices.

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Our Manager of Engineering is primarily responsible for overseeing the preparation of the Company's reserve estimate by our independent third party engineers, Wright & Company, Inc. The Manager of Engineering has over 24 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

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

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Item 1A, "Risk Factors."

Production and Reserves by Region

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

	As of December 31, 2010			As of December 31, 2009		
Region	**Proved Reserves**	**% of Total Proved Reserves**	**% Proved Developed**	**Proved Reserves**	**% of Total Proved Reserves**	**% Proved Developed**
	(Bcfe)			(Bcfe)		
Texas	448	48%	38%	403	43%	31%
Appalachia	120	13%	95%	134	14%	79%
Mid-Continent	192	20%	60%	199	21%	37%
Mississippi	182	19%	57%	175	19%	57%
Gulf Coast [1]	-	-	-	24	3%	92%
	942	100%		935	100%	

	Average Daily Production for the Year Ended December 31,			Total Production for the Year Ended December 31,		
Region	**2010**	**2009**	**2008**	**2010**	**2009**	**2008**
		(MMcfe)			(MMcfe)	
Texas	37.1	35.9	36.6	13,526	13,116	13,409
Appalachia	28.5	31.4	31.4	10,397	11,465	11,497
Mid-Continent	42.0	35.1	20.9	15,340	12,826	7,646
Mississippi	20.9	21.5	20.1	7,643	7,822	7,340
Gulf Coast [1]	0.8	15.8	19.1	295	5,771	6,989
	129.3	139.7	128.1	47,201	51,000	46,881

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

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2010. The acreage is located primarily in Texas, Appalachia, the Mid-Continent and Mississippi regions of the United States.

	Gross Acreage	**Net Acreage**
	(in thousands)	
Developed	1,071	886
Undeveloped	558	314
	1,629	1,200

Wells Drilled

The following table sets forth the gross and net numbers of exploratory and development wells that we drilled during the years ended December 31, 2010, 2009 and 2008. The number of wells drilled refers to the number of wells reaching total depth at any time during the respective year. Net wells equal the number of gross wells multiplied by our working interest in each of the gross wells. Productive wells represent either wells that were producing oil or gas or were capable of commercial production.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	59	40.0	25	16.9	259	160.5
Non-productive	-	-	1	1.0	4	3.0
Under evaluation	-	-	4	1.8	11	8.8
Total development	59	40.0	30	19.7	274	172.3
Exploratory						
Productive	5	2.7	2	1.0	6	3.5
Non-productive	3	1.2	-	-	5	2.8
Under evaluation	1	0.5	-	-	1	1.0
Total exploratory	9	4.4	2	1.0	12	7.3
Total	68	44.4	32	20.7	286	179.6

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we had a working interest as of December 31, 2010.

Operated Wells		Non-Operated Wells		Total Wells	
Gross	Net	Gross	Net	Gross	Net
1,642	1,474.2	487	107.5	2,129	1,581.7

In addition to the above working interest wells, we own royalty interests in 2,911 gross wells.

Item 3 ***Legal Proceedings***

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

Item 4 ***Reserved***

Part II

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

Market Information

Our common stock is traded on the NYSE under the symbol "PVA." The high and low sales prices (composite transactions) and dividends declared related to each fiscal quarter in 2010 and 2009 were as follows:

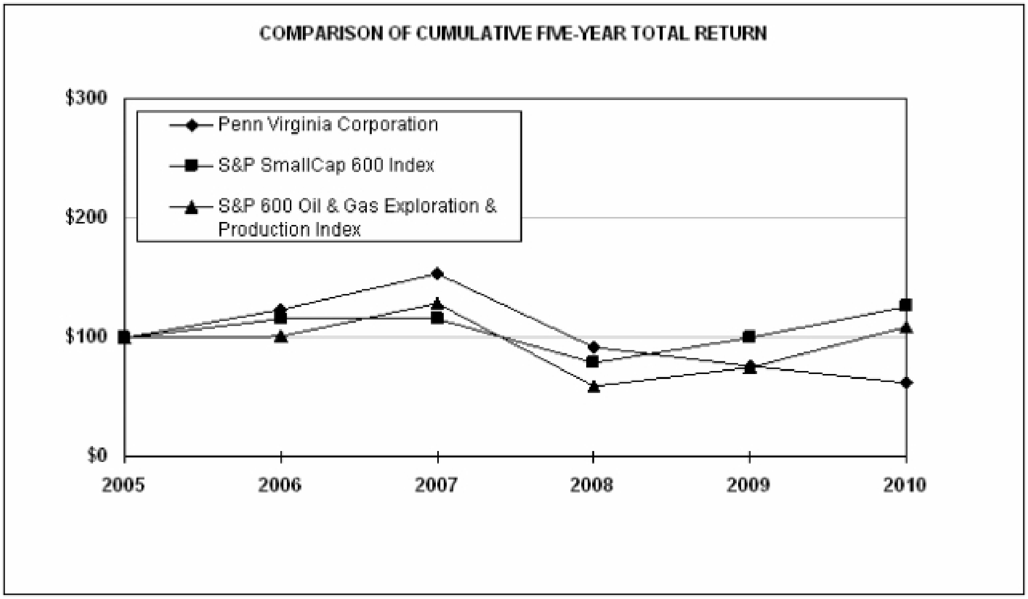
Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2010	$ 18.80	$ 14.29	$ 0.05625
September 30, 2010	$ 20.50	$ 13.38	$ 0.05625
June 30, 2010	$ 29.25	$ 19.63	$ 0.05625
March 31, 2010	$ 27.80	$ 21.64	$ 0.05625
December 31, 2009	$ 26.32	$ 17.25	$ 0.05625
September 30, 2009	$ 23.92	$ 13.16	$ 0.05625
June 30, 2009	$ 23.24	$ 10.46	$ 0.05625
March 31, 2009	$ 31.53	$ 7.22	$ 0.05625

Equity Holders

As of February 11, 2011, there were 464 record holders and approximately 6,200 beneficial owners (held in street name) of our common stock.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration & Production Index and the Standard & Poor's Small Cap 600 Index. There are seven companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Contango Oil & Gas Company, Gulfport Energy Corporation, Penn Virginia Corporation, Petroleum Development Corporation, Petroquest Energy Inc., Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2006 in us and each index at December 31, 2005 closing prices.



	December 31,				
	2006	2007	2008	2009	2010
Penn Virginia Corporation	$ 122.79	$ 153.86	$ 92.07	$ 76.44	$ 61.14
S&P Small Cap 600 Index	$ 115.12	$ 114.78	$ 79.11	$ 99.34	$ 125.47
S&P 600 Oil & Gas Exploration & Production Index	$ 100.91	$ 127.79	$ 58.95	$ 75.09	$ 109.18

Item 6 ***Selected Financial Data***

The following selected historical financial information was derived from our Consolidated Financial Statements as of and for the years ended December 31, 2010, 2009, 2008, 2007 and 2006. The selected financial data should be read in conjunction with our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and Item 8, “Financial Statements and Supplementary Data.”

	2010	2009	2008	2007	2006
	(in thousands, except per share amounts)				
Statements of Income Data [1]:					
Revenues	$ 254,438	$ 235,206	$ 469,490	$ 303,505	$ 236,038
Depreciation, depletion and amortization	$ 134,700	$ 154,351	$ 135,687	$ 88,237	$ 56,724
Operating income (loss) [2]	$ (98,808)	$ (205,346)	$ 142,034	$ 77,155	$ 68,109
Income (loss) from continuing operations	$ (65,327)	$ (130,856)	$ 93,619	$ 35,196	$ 56,806
Net income (loss) [3]	$ 19,667	$ (77,368)	$ 181,520	$ 80,810	$ 118,927
Income (loss) attributable to Penn Virginia Corporation	$ (8,423)	$ (114,643)	$ 121,084	$ 50,491	$ 75,909
Common Stock Data [1, 4]:					
Earnings (loss) per common share, basic					
Continuing operations	$ (1.44)	$ (2.99)	$ 2.23	$ 0.92	$ 1.52
Discontinued operations	$ 0.12	$ 0.37	$ 0.66	$ 0.40	$ 0.51
Gain on sale of discontinued operations	$ 1.13	$ -	$ -	$ -	$ -
Net income (loss)	$ (0.19)	$ (2.62)	$ 2.89	$ 1.32	$ 2.03
Earnings (loss) per common share, diluted					
Continuing operations	$ (1.44)	$ (2.99)	$ 2.22	$ 0.91	$ 1.50
Discontinued operations	$ 0.12	$ 0.37	$ 0.65	$ 0.40	$ 0.51
Gain on sale of discontinued operations	$ 1.13	$ -	$ -	$ -	$ -
Net income (loss)	$ (0.19)	$ (2.62)	$ 2.87	$ 1.31	$ 2.01
Weighted-average shares outstanding:					
Basic	45,553	43,811	41,760	38,061	37,362
Diluted	45,553	43,811	42,031	38,358	37,732
Actual shares outstanding at year-end	45,557	45,272	41,786	41,331	37,490
Dividends declared per share	$ 0.225	$ 0.225	$ 0.225	$ 0.225	$ 0.225
Market value at year-end	$ 16.82	$ 21.29	$ 25.66	$ 42.89	$ 34.23
Number of shareholders	6,708	3,486	8,761	8,196	7,970
Balance Sheet and Other Financial Data [1]:					
Property and equipment, net	$ 1,705,584	$ 1,479,452	$ 1,646,215	$ 1,198,506	$ 801,870
Total assets	$ 1,944,600	$ 2,888,507	$ 2,996,565	$ 2,253,461	$ 1,633,149
Total debt	$ 506,536	$ 498,427	$ 539,438	$ 315,655	$ 221,000
Shareholders' equity	$ 980,276	$ 1,237,999	$ 1,222,442	$ 911,700	$ 815,848
Cash provided by operating activities	$ 77,861	$ 117,733	$ 246,587	$ 186,550	$ 175,136
Capital expenditures	$ 405,994	$ 205,676	$ 547,058	$ 488,470	$ 335,227
Other Statistical Data:					
Total production (MMcfe)	47,201	51,000	46,881	40,569	31,260
Proved reserves (Bcfe)	942	935	916	680	487

[1] PVG's results of operations, financial position and cash flows have been reported as discontinued operations for all periods presented. Accordingly, all items presented above not classified as discontinued operations exclude amounts attributable to PVG unless indicated otherwise.

[2] Operating income (loss) for 2010, 2009, 2008, 2007 and 2006 included impairment charges of $46.0 million, $106.4 million, $20.0 million, $2.6 million and $8.5 million related to our oil and gas properties and other assets.

[3] Net income (loss) for 2010 includes a gain of $51.5 million on the sale of discontinued operations representing the final disposition of our interests in PVG.

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

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

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

Overview of Business

We are an independent oil and gas company engaged primarily in the exploration, development and production of natural gas and oil in various domestic onshore regions. We have a geographically diverse asset base with core areas of operations in Texas, Appalachia, the Mid-Continent and Mississippi regions of the United States. As of December 31, 2010, we had proved natural gas and oil reserves of approximately 942 Bcfe. Our operations include both conventional and unconventional development drilling opportunities, as well as some exploratory prospects.

The primary development play type that we focused on in 2010 was the horizontal Granite Wash play in Mid-Continent. We have expanded development drilling with our recent acquisition of properties in the Eagle Ford Shale play in Texas, and we intend to focus on drilling exploratory wells in the Marcellus Shale play in Appalachia to determine whether our leasehold acreage position will support a development program.

The following table sets forth certain summary operating and financial statistics for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Total production (MMcfe)	47,201	51,000	46,881
Daily production (MMcfe per day)	129.3	139.7	128.4
Realized prices per Mcfe, as reported	$ 5.32	$ 4.48	$ 9.31
Realized prices per Mcfe, adjusted for derivatives	$ 6.03	$ 5.66	$ 9.15
Product revenues, as reported	$ 251,336	$ 228,659	$ 436,622
Product revenues, as adjusted for derivatives	$ 284,816	$ 288,565	$ 429,002
Operating income (loss)	$ (98,808)	$ (205,346)	$ 142,034
Interest expense	$ 53,679	$ 44,231	$ 24,627
Cash provided by operating activities	$ 77,861	$ 117,733	$ 246,587
Cash paid for capital expenditures	$ 405,994	$ 205,676	$ 547,058
Cash and cash equivalents at end of period	$ 120,911	$ 79,017	$ -
Debt outstanding, net of discounts, at end of period	$ 506,536	$ 498,427	$ 531,896
Credit available under Revolver at end of period	$ 299,268	$ 299,268	$ 366,268
Net development wells drilled	40.0	19.7	172.3
Net exploratory wells drilled	4.4	1.0	7.3

Key Developments

During 2010, the following general business developments and corporate actions had an impact upon the financial reporting of our results of operations and financial position as well as the overall presentation of financial information: (i) the complete divestiture of our interests in PVG, (ii) significant leasehold acquisitions of properties in the Eagle Ford and Marcellus Shale plays, (iii) execution of a fracturing services agreement for well completion activities, (iv) the completion of our organization restructuring that was announced in the fourth quarter of 2009 and (v) disposition of our Gulf Coast properties.

Divestiture and Deconsolidation of PVG

Prior to June 2010, we indirectly owned partner interests in Penn Virginia Resource Partners, L.P., or PVR, which is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR were held primarily through our general and limited partner interests in PVG. In June 2010, we completed the sale of our remaining limited partner interests in PVG in a secondary public offering for proceeds of approximately $139 million, net of offering costs. In a related transaction, we disposed of 100% of the membership interest in PVG's general partner, thereby relinquishing control of PVG. As a result of these transactions, we recognized a gain of $51.5 million, net of taxes, during the three months ended June 30, 2010 and have deconsolidated PVG from our Consolidated Financial Statements. The results of operations attributable to PVG through the date of these transactions and prior periods have been presented as discontinued operations in our Consolidated Financial Statements. Since September 2009, we sold an aggregate of approximately 30.1 million common units of PVG for approximately $450 million in net pre-tax proceeds. Additional information is provided in the Liquidity and Capital Resources discussion that follows.

Property Acquisitions

In August 2010, we acquired approximately 6,800 net acres in the Eagle Ford Shale play in Texas for approximately $31.1 million. The acreage includes over 40 potential horizontal well locations. We are the operator with a working interest of approximately 75% and a net revenue interest of approximately 57%. We recently announced a second Eagle Ford Shale acquisition of approximately 4,100 net acres with approximately 40 horizontal well locations for $14.5 million. We will operate the wells drilled on the acquired acreage and we expect our existing partner in the Eagle Ford Shale to purchase up to a one-sixth working interest. The acquisition brings our net Eagle Ford Shale acreage to approximately 10,200 net acres assuming our partner purchases a one-sixth working interest.

During 2010, we acquired a total of approximately 27,000 net acres in the Marcellus Shale play in Pennsylvania for approximately $69 million bringing our holdings in the area to approximately 56,000 net acres as of December 31, 2010.

Fracturing Services Agreement

In May 2010, we entered into a one-year agreement commencing in July 2010 with C&J Energy Services, Inc. to provide high pressure hydraulic fracturing services in our Texas and Mid-Continent regions. The supply of such services and related equipment was constrained in those regions, which led to delays in well completions during the first half of the year. As a result of the agreement, we have secured access to equipment and services necessary to complete the backlog of wells drilled, as well as wells to be drilled through the first half of 2011. The agreement was subsequently amended to provide for equipment and services into the South Texas region in support of our expansion into the Eagle Ford Shale play. The agreement will automatically renew in 2011 on similar terms unless the Company chooses to terminate after the initial term is complete.

Organization Restructuring

In November 2009, we implemented an organization restructuring that resulted in the transfer of certain corporate and oil and gas accounting and administrative functions from our Kingsport, Tennessee office location to our Houston, Texas and Radnor, Pennsylvania locations. In addition, the restructuring resulted in the relocation of our eastern region oil and gas divisional office from Kingsport to Pittsburgh, Pennsylvania. During 2010, we expanded the program to restructure key operational and management positions to complete our transformation to a pure play E&P company. Approximately 30 employees were terminated in connection with the restructuring, which was substantially completed during the second quarter of 2010. In 2010, we incurred $4.7 million in costs including termination benefits, relocation costs and other incremental costs associated with expanding our other office locations. In addition, we incurred a charge of $3.5 million in connection with the assignment of a lease for our former Kingsport, Tennessee office facility to PVR. We anticipate an additional $0.4 million in costs, primarily related to employee relocation, to be incurred during 2011 attributable to the restructuring program.

Disposition of Gulf Coast Properties

In January 2010, we completed the sale of our Gulf Coast properties in exchange for cash proceeds of $23.4 million, net of transaction costs and purchase and sale adjustments, plus the receipt of certain oil and gas properties in the Selma Chalk play in our Mississippi region.

Results of Operations

Year Ended December 31, 2010 Compared With Year Ended December 31, 2009

The following table sets forth a summary of certain operating and financial performance for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Total Production:				
Natural gas (MMcf)	38,919	43,338	(4,419)	(10%)
Crude oil (MBbl)	709	750	(41)	(6%)
NGL (MBbl)	672	527	145	27%
Total production (MMcfe)	47,201	51,000	(3,799)	(7%)
Realized prices, before derivatives:				
Natural gas ($/Mcf)	$ 4.40	$ 3.91	$ 0.49	13%
Crude oil ($/Bbl)	75.56	57.68	17.88	31%
NGL ($/Bbl)	39.69	29.86	9.83	33%
Total ($/Mcfe)	$ 5.32	$ 4.48	$ 0.84	19%
Revenues				
Natural gas	$ 171,141	$ 169,666	$ 1,475	1%
Crude oil	53,532	43,258	10,274	24%
NGL	26,663	15,735	10,928	69%
Total product revenues	251,336	228,659	22,677	10%
Gain on sale of property and equipment	648	2,372	(1,724)	(73%)
Other income	2,454	4,175	(1,721)	(41%)
Total revenues	254,438	235,206	19,232	8%
Operating Expenses				
Lease operating	35,757	44,392	8,635	19%
Gathering, processing and transportation	14,180	11,307	(2,873)	(25%)
Production and ad valorem taxes	13,917	15,044	1,127	7%
General and administrative	58,383	49,690	(8,693)	(17%)
Exploration	49,641	57,754	8,113	14%
Depreciation, depletion and amortization	134,700	154,351	19,651	13%
Impairments	45,959	106,415	60,456	57%
Other	709	1,599	890	56%
Total operating expenses	353,246	440,552	87,306	20%
Operating loss	(98,808)	(205,346)	106,538	52%
Other income (expense)				
Interest expense	(53,679)	(44,231)	(9,448)	(21%)
Derivatives	41,906	31,568	10,338	33%
Other	2,403	1,259	1,144	91%
Loss from continuing operations before income taxes	(108,178)	(216,750)	108,572	(50%)
Income tax benefit	42,851	85,894	(43,043)	(50%)
Loss from continuing operations	(65,327)	(130,856)	65,529	(50%)
Income from discontinued operations, net of tax	33,448	53,488	(20,040)	(37%)
Gain on sale of discontinued operations, net of tax	51,546	-	51,546	n/a
Net income (loss)	19,667	(77,368)	97,035	125%
Less net income attributable to noncontrolling interests	(28,090)	(37,275)	9,185	25%
Net loss attributable to Penn Virginia Corporation	$ (8,423)	$ (114,643)	$ 106,220	93%

Production

The following tables set forth a summary of our total and daily production volumes by geographical region for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	13,526	13,116	410	37.1	35.934	1.1	3%
Appalachia	10,397	11,465	(1,068)	28.5	31.411	(2.9)	(9%)
Mid-Continent	15,340	12,826	2,514	42.0	35.140	6.9	20%
Mississippi	7,643	7,822	(179)	20.9	21.500	(0.6)	(3%)
Gulf Coast	295	5,771	(5,476)	0.8	15.811	(15.0)	(95%)
Total production	47,201	51,000	(3,799)	129.3	139.726	(10.5)	(7%)

The decline in production during 2010 was attributable to the disposition of our Gulf Coast properties in January 2010, the significant reduction in drilling activity in 2009, as well as natural declines in production rates. These natural declines were expected to be replaced with new production associated with 2010 drilling; however, we experienced equipment and service-related delays in new well completions during the first half of 2010 primarily in the Lower Bossier (Haynesville) Shale play in the Texas region. In order to address this issue, we secured critical fracturing and completion services from a vendor for a one-year period which began in July 2010. This action allowed us to avoid further delays and make substantial progress in completing our backlog of wells in addition to executing our larger drilling program. The overall decline in production volume was partially offset by production from new wells in the Granite Wash play in the Mid-Continent region that were brought online during 2010 despite interference attributable to offset wells during stimulation causing temporary reductions in production.

NGL production increased 20% to 18% of the total production in 2010 compared to 15% in 2009. This change reflects our current focus on liquids-rich regions in the Mid-Continent and Texas. In addition, a processing agreement was signed for a major portion of our Granite Wash production which contributed to the increase in 2010 NGL production.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per Mcfe by geographical region for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)
				($ per Mcfe)		
Texas	$ 67,241	$ 55,159	$ 12,082	$ 4.97	$ 4.21	$ 0.76
Appalachia	45,796	46,863	(1,067)	4.40	4.09	0.31
Mid-Continent	101,022	63,720	37,302	6.59	4.97	1.62
Mississippi	35,101	32,792	2,309	4.59	4.19	0.40
Gulf Coast	2,176	30,125	(27,949)	7.38	5.22	2.16
Total revenues	$ 251,336	$ 228,659	$ 22,677	$ 5.32	$ 4.48	$ 0.84

As illustrated below, revenues were higher compared to the prior year period as the decline in production volume discussed above was more than offset by improved pricing for all three commodity product types. The following table provides an analysis of the change in our revenues for the year ended December 31, 2010 as compared to the year ended December 31, 2009:

	Revenue Variance Due to Volume	Revenue Variance Due to Price	Total
Natural gas	$ (17,301)	$ 18,776	$ 1,475
Crude oil	(2,393)	12,667	10,274
NGL	4,323	6,605	10,928
	$ (15,371)	$ 38,048	$ 22,677

Effects of Derivatives

Our natural gas and crude oil revenues may change significantly from period to period as a result of changes in commodity prices. As part of our risk management strategy, we use derivative financial instruments to hedge natural gas and, to a lesser extent, oil prices. We received $33.5 million and $59.9 million in cash settlements of oil and gas derivatives in 2010 and 2009, respectively.

The following table reconciles natural gas and crude oil revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Natural gas revenues as reported	$ 171,141	$ 169,666	$ 1,475	1%
Cash settlements on natural gas derivatives	33,914	55,545	(21,631)	(39%)
Natural gas revenues adjusted for derivatives	$ 205,055	$ 225,211	$ (20,156)	(9%)
Natural gas prices per Mcf, as reported	$ 4.40	$ 3.91	$ 0.49	12%
Cash settlements on natural gas derivatives per Mcf	0.87	1.28	(0.41)	(32%)
Natural gas prices per Mcf adjusted for derivatives	$ 5.27	$ 5.19	$ 0.08	2%
Crude oil revenues as reported	$ 53,532	$ 43,258	$ 10,274	24%
Cash settlements on crude oil derivatives	(434)	4,361	(4,795)	(110%)
Crude oil revenues adjusted for derivatives	$ 53,098	$ 47,619	$ 5,479	12%
Crude oil prices per Bbl, as reported	$ 75.56	$ 57.68	$ 17.88	31%
Cash settlements on crude oil derivatives per Bbl	(0.61)	5.81	(6.43)	(111%)
Crude oil prices per Bbl adjusted for derivatives	$ 74.94	$ 63.49	$ 11.45	18%

Gain on Sale of Property and Equipment

In 2010, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well materials. In 2009, we recognized gains on the sale of certain properties and equipment in our Texas region.

Other Income

Other income decreased primarily as a result of lower gathering revenues during 2010 and the effect of a favorable audit settlement during 2009 partially offset by higher compression services revenues.

Operating Expenses

The following table summarizes our operating expenses per Mcfe for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Lease operating	$ 0.76	$ 0.87	$ 0.11	13%
Gathering, processing and transportation	0.30	0.22	(0.08)	(36%)
Production and ad valorem taxes	0.29	0.29	0.00	0%
General and administrative	1.24	0.97	(0.27)	(27%)
General and administrative excluding share-based compensation and restructuring charges	0.90	0.78	(0.12)	(15%)
Depreciation, depletion and amortization	2.85	3.03	0.18	6%

Lease Operating

The most significant decline in lease operating expenses resulted from decreases in charges that are generally correlated with production volume including water disposal, compressor and other equipment rentals, contract labor, chemical and treating and repairs and maintenance costs.

Gathering, Processing and Transportation

Gathering, processing and transportation charges increased during 2010 primarily as a result of a settlement with a gathering services provider attributable to disputed charges in several prior periods, as well as a change in the geographic distribution of production from the Gulf Coast to the Mid-Continent region where we typically experience higher processing costs associated with NGLs. These items were offset partially by the effects of lower volume in the current period.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased by $1.1 million reflecting ad valorem tax settlements of approximately $1.4 million with certain jurisdictions attributable to prior periods while production and ad valorem taxes increased commensurately with higher revenues. As a percentage of revenue, production and ad valorem taxes, excluding the settlements, decreased to 6.1% in 2010 from 6.6% during 2009.

General and Administrative

Higher general and administrative expenses in 2010 include restructuring charges of $4.7 million attributable to termination benefits, office and employee relocation and other costs associated with the organization restructuring announced during November 2009, as well as a $3.5 million charge related to the assignment of our lease of our former Kingsport, Tennessee office facility to PVR. Exclusive of these charges, our 2010 general and administrative charges were generally comparable to amounts incurred in 2009 although we incurred higher consulting and professional fees offset partially by lower share-based compensation expense.

Exploration

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

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
Dry hole costs	$ 11,282	$ 1,397	$ (9,885)	(708%)
Geological and geophysical	10,168	912	(9,256)	(1015%)
Unproved leasehold	24,993	31,618	6,625	21%
Rig standby charges	-	20,084	20,084	n/a
Other, primarily delay rentals	3,198	3,743	545	15%
	$ 49,641	$ 57,754	$ 8,113	14%

The decrease in exploration expense is attributable primarily to rig standby charges incurred during 2009. These charges were a direct result of our 2009 drilling program reduction due to unfavorable economic conditions. In addition, the 2009 period reflects the initial impact of a change in accounting estimate to amortize collectively insignificant unproved properties over the average estimated life of the leases rather than amortizing some leases and assessing other leases individually. The decrease was offset partially by dry hole costs in the Mid-Continent region incurred during 2010 and higher geological and geophysical costs attributable to our larger 2010 exploration program.

Depreciation, Depletion and Amortization (DD&A)

The following tables set forth the components of DD&A and the nature of the variances for the periods presented:

	Year Ended December 31, 2010	2009	Favorable (Unfavorable)	% Change
Depreciation - Oil and gas operations	$ 2,536	$ 2,756	$ 220	8%
Depreciation - Corporate	3,884	3,922	38	1%
Depletion	127,836	147,174	19,338	13%
Amortization	444	499	55	11%
	$ 134,700	$ 154,351	$ 19,651	13%

	DD&A Variance Due to Production	Rates	Total
Year ended December 31, 2010 compared to 2009	$ 11,499	$ 8,152	$ 19,651

Our average depletion rate decreased by $0.18 per Mcfe, or 6%, to $2.71 per Mcfe in 2010 from $2.89 per Mcfe in 2009. The reduction was a result of discoveries and the impact of impairments in 2010.

Impairments

The following table summarizes impairment charges recorded for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Oil and gas properties - held for sale	$ 1,124	$ 97,400	$ 96,276	n/a
Oil and gas properties	43,067	4,932	(38,135)	(773%)
Other - tubular inventory and well materials	1,768	4,083	2,315	57%
	$ 45,959	$ 106,415	$ 60,456	57%

During 2010, we incurred impairment charges related to our coal bed methane properties as a result of market declines in gas prices and to an area in the Anadarko basin of the Mid-Continent region where we drilled an uneconomic well. In addition, we recorded impairment charges attributable to certain oil and gas inventory assets triggered primarily by declines in asset quality. We also incurred impairment charges on properties in North Dakota that were held for sale at the end of 2009. These properties were ultimately sold during 2010. During 2009, we incurred impairment charges in connection with the initial classification of the Gulf Coast properties as assets held for sale at their fair value less costs to sell, as well as impairments attributable to tubular inventory and other oil and gas properties.

Other

During 2010, we recorded a loss of $0.7 million on the disposition of our Gulf Coast properties. The loss reflects final purchase price adjustments associated with the period from the effective date in October 2009 to the closing date in January 2010. The 2009 period reflects a loss on the sales of tubular inventory and well materials.

Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Interest on borrowings and related fees	$ 43,060	$ 33,374	$ (9,686)	(29%)
Accretion of original issue discount	8,109	7,523	(586)	(8%)
Amortization of debt issuance costs	3,875	2,679	(1,196)	(45%)
Interest rate swaps	-	3,969	3,969	n/a
Capitalized interest	(1,384)	(2,318)	(934)	(40%)
Other, net	19	(996)	(1,015)	n/a
	$ 53,679	$ 44,231	$ (9,448)	(21%)

Interest expense increased due to higher interest rates on outstanding borrowings, primarily the 10.375% Senior Unsecured Notes, or Senior Notes, issued in June 2009. We realized higher amortization of the original issue discount and issuance costs on the Senior Notes and 4.5% Convertible Notes, or Convertible Notes, as well as higher amortization of issuance costs associated with the revolving credit facility, or Revolver. In addition, 2009 included a reclassification of expense from accumulated other comprehensive income, or AOCI, attributable to the discontinuation of hedge accounting related to our interest rate swaps, as well as a reversal of interest cost attributable to the settlement of various state income tax positions.

Derivatives

The components of our derivatives income are presented below for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Oil and gas derivative unrealized derivative gain (loss)	$ 3,213	$ (26,690)	$ 29,903	112%
Oil and gas derivative realized gain	33,480	59,908	(26,428)	(44%)
Interest rate swap unrealized gain	5,875	111	5,764	5193%
Interest rate swap realized loss	(662)	(1,761)	1,099	62%
	$ 41,906	$ 31,568	$ 10,338	33%

Cash received for settlements during 2010 was $32.8 million as compared to $58.1 million during 2009.

Other

Other income increased during 2010 due primarily to the gains on the sale of non-operating investments as well as higher interest income on the significantly larger cash balances held following of the disposition of our interests in PVG.

Income Taxes

The effective tax benefit rate for continuing operations during 2010 was 39.6% for 2010 and 2009. Due to the operating losses incurred, we recognized an income tax benefit during both periods.

Discontinued Operations

The following table presents a summary of results of operations from discontinued operations for the periods presented:

	Year Ended December 31, 2010	Year Ended December 31, 2009	Favorable (Unfavorable)	% Change
Revenues	$ 303,206	$ 579,931	$ (276,725)	48%
Income from discontinued operations before taxes	$ 36,832	$ 64,130	$ (27,298)	43%
Income tax expense [1]	(3,384)	(10,642)	7,258	68%
Income from discontinued operations, net of taxes	$ 33,448	$ 53,488	$ (20,040)	37%

[1] Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests that are fully attributable to PVG's operations.

The disclosures for 2010 provided in the table above reflect the results of operations of PVG through the date of disposition of our entire remaining interest in PVG on June 7, 2010.

Gain on Sale of Discontinued Operations

The following table summarizes the determination of the gain recognized on the disposition of PVG:

Cash proceeds, net of offering costs (8,827,429 units x $15.76 per unit)	$ 139,120
Carrying value of noncontrolling interests in PVG at date of disposition	382,324
	521,444
Less: Carrying value of PVG's assets and liabilities at date of disposition	(434,782)
	86,662
Less: Income tax expense	(35,116)
Gain on sale of discontinued operations, net of tax	$ 51,546

Noncontrolling Interests

The decrease in net income attributable to noncontrolling interests during 2010 is directly attributable to the sale of our interests in PVG during June 2010. In September 2009, our ownership interest in PVG declined from 77.0% to 51.4% and in 2010 our ownership interest in PVG declined to zero.

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

The following table sets forth a summary of certain operating and financial performance for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Total Production:				
Natural gas (MMcf)	43,338	41,493	1,845	4%
Crude oil (MBbl)	750	506	244	48%
NGL (MBbl)	527	392	135	34%
Total production (MMcfe)	51,000	46,881	4,119	9%
Realized prices, before derivatives:				
Natural gas ($/Mcf)	$ 3.91	$ 8.89	$ (4.98)	(56%)
Crude oil ($/Bbl)	57.68	91.95	(34.27)	(37%)
NGL ($/Bbl)	29.86	54.32	(24.46)	(45%)
Total ($/Mcfe)	$ 4.48	$ 9.31	$ (4.83)	(52%)
Revenues				
Natural gas	$ 169,666	$ 368,801	$ (199,135)	(54%)
Crude oil	43,258	46,529	(3,271)	(7%)
NGL	15,735	21,292	(5,557)	(26%)
Total product revenues	228,659	436,622	(207,963)	(48%)
Gain on sale of property and equipment	2,372	31,426	(29,054)	(92%)
Other income	4,175	1,442	2,733	190%
Total revenues	235,206	469,490	(234,284)	(50%)
Operating Expenses				
Lease operating	44,392	51,419	7,027	14%
Gathering, processing and transportation	11,307	8,105	(3,202)	(40%)
Production and ad valorem taxes	15,044	22,369	7,325	33%
General and administrative	49,690	47,477	(2,213)	(5%)
Exploration	57,754	42,436	(15,318)	(36%)
Depreciation, depletion and amortization	154,351	135,687	(18,664)	(14%)
Impairments	106,415	19,963	(86,452)	(433%)
Other	1,599	-	(1,599)	n/a
Total operating expenses	440,552	327,456	(113,096)	(35%)
Operating loss	(205,346)	142,034	(347,380)	245%
Other income (expense)				
Interest expense	(44,231)	(24,627)	(19,604)	(80%)
Derivatives	31,568	29,745	1,823	6%
Other	1,259	2,073	(814)	(39%)
Income (loss) from continuing operations before income taxes	(216,750)	149,225	(365,975)	(245%)
Income tax (expense) benefit	85,894	(55,606)	141,500	(254%)
Income (loss) from continuing operations	(130,856)	93,619	(224,475)	(240%)
Income from discontinued operations, net of tax	53,488	87,901	(34,413)	(39%)
Net income (loss)	(77,368)	181,520	(258,888)	143%
Less net income attributable to noncontrolling interests	(37,275)	(60,436)	23,161	38%
Net income (loss) attributable to Penn Virginia Corporation	$ (114,643)	$ 121,084	$ (235,727)	195%

Production

The following tables set forth a summary of our total and daily production volumes by geographical region for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
	(MMcfe)			(MMcfe per day)			
Texas	13,116	13,409	(293)	35.9	36.7	(0.8)	(2%)
Appalachia	11,465	11,497	(32)	31.4	31.5	(0.1)	(0%)
Mid-Continent	12,826	7,646	5,180	35.1	20.9	14.2	68%
Mississippi	7,822	7,340	482	21.5	20.1	1.4	7%
Gulf Coast	5,771	6,989	(1,218)	15.8	19.1	(3.3)	(17%)
Total production	51,000	46,881	4,119	139.7	128.4	11.4	9%

Approximately 85% and 89% of total production in the years ended December 31, 2009 and 2008 was natural gas. Total production increased primarily due to continued development of the Granite Wash play in the Mid-Continent region and the horizontal Selma Chalk play in Mississippi. During the second half of 2009, we deferred drilling in the Texas region until early 2010 and we began the process of exiting all of our activities in the Gulf Coast region during the fourth quarter of 2009 in connection with the sale of these properties which was consummated in January 2010.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per Mcfe by geographical region for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)
				($ per Mcfe)		
Texas	$ 55,159	$ 129,105	$ (73,946)	$ 4.21	$ 9.63	$ (5.42)
Appalachia	46,863	107,282	(60,419)	4.09	9.33	(5.24)
Mid-Continent	63,720	59,969	3,751	4.97	7.84	(2.87)
Mississippi	32,792	69,916	(37,124)	4.19	9.53	(5.34)
Gulf Coast	30,125	70,350	(40,225)	5.22	10.07	(4.85)
Total revenues	$ 228,659	$ 436,622	$ (207,963)	$ 4.48	$ 9.31	$ (4.83)

As illustrated below, revenues declined in 2009 due primarily to a decline in pricing for all three commodity product types, despite an increase in overall production volume. The following table provides an analysis of the change in our revenues for the year ended December 31, 2009 as compared to the year ended December 31, 2008:

	Revenue Variance Due to Volume	Revenue Variance Due to Price	Total
Natural gas	$ 16,399	$ (215,534)	$ (199,135)
Crude oil	22,437	(25,708)	(3,271)
NGL	7,333	(12,890)	(5,557)
	$ 46,169	$ (254,132)	$ (207,963)

Effects of Derivatives

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

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Natural gas revenues as reported	$ 169,666	$ 368,801	$ (199,135)	(54%)
Cash settlements on natural gas derivatives	55,545	(7,339)	62,884	(857%)
Natural gas revenues adjusted for derivatives	$ 225,211	$ 361,462	$ (136,251)	(38%)
Natural gas prices per Mcf, as reported	$ 3.91	$ 8.89	$ (4.97)	(56%)
Cash settlements on natural gas derivatives per Mcf	1.28	(0.18)	1.46	(811%)
Natural gas prices per Mcf adjusted for derivatives	$ 5.20	$ 8.71	$ (3.51)	(40%)
Crude oil revenues as reported	$ 43,258	$ 46,529	$ (3,271)	(7%)
Cash settlements on crude oil derivatives	4,361	(281)	4,642	(1652%)
Crude oil revenues adjusted for derivatives	$ 47,619	$ 46,248	$ 1,371	3%
Crude oil prices per Bbl, as reported	$ 57.68	$ 91.95	$ (34.28)	(37%)
Cash settlements on crude oil derivatives per Bbl	5.81	(0.56)	6.37	(1138%)
Crude oil prices per Bbl adjusted for derivatives	$ 63.49	$ 91.40	$ (27.91)	(31%)

Gain on Sale of Property and Equipment

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

Other Income

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

Operating Expenses

The following table summarizes our operating expenses per Mcfe for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Lease operating	$ 0.87	$ 1.10	$ 0.23	21%
Gathering, processing and transportation	0.22	0.17	(0.05)	(29%)
Production and ad valorem taxes	0.29	0.48	0.19	40%
General and administrative	0.97	1.01	0.04	4%
General and administrative excluding share-based compensation and restructuring charges	0.79	0.89	0.10	11%
Depreciation, depletion and amortization	3.03	2.89	(0.14)	(5%)

Lease Operating

The most significant declines in lease operating expenses was attributable to lower repair and maintenance costs and lower water disposal fees.

Gathering, Processing and Transportation

Gathering, processing and transportation charges increased in certain regions due to a change in the geographical distribution of production from the Gulf Coast to the Mid-Continent region reflecting higher processing costs for NGLs. In addition, the increase reflects overall higher volume during 2009.

Production and Ad Valorem Taxes

Production and ad valorem taxes decreased commensurately with the decrease in product revenues, partially offset by the impact of higher production volume. As a percentage of revenue, production and ad valorem taxes increased to 6.6% during 2009 from 5.1% during 2008.

General and Administrative

Higher general and administrative expenses in 2009 include restructuring charges of $0.5 million attributable to accrued termination benefits associated with the organization restructuring announced in November 2009. In addition, we incurred $3.2 million of higher stock-based compensation expense during 2009. These charges were partially offset by lower consulting and professional fees, including information technology-related fees, and lower bad debt expense during 2009.

Exploration

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

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

In 2009, dry hole costs and geological and geophysical expenses were significantly decreased due to our reduced drilling program. In 2008, the dry hole costs were primarily due to the write-off of six wells in the Appalachian region. The 2009 unproved leasehold reflects the initial impact of a change in accounting estimate to amortize collectively insignificant unproved properties over the average estimated life of the leases rather than amortizing some leases and assessing other leases individually. In conjunction with the drilling program reduction, we amended certain drilling rig contracts to delay commencement of drilling until January 2010. As a result, in 2009 we recognized significant standby rig charges for cancellation fees, minimum daily standby fees and demobilization fees. Other expenses increased due to higher delay rentals in the Gulf Coast region.

Depreciation, Depletion and Amortization (DD&A)

The following tables set forth the components of DD&A and the nature of the variances for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Depreciation - Oil and gas operations	$ 2,756	$ 2,434	$ (322)	(13%)
Depreciation - Corporate	3,922	3,411	(511)	(15%)
Depletion	147,174	129,408	(17,766)	(14%)
Amortization	499	434	(65)	(15%)
	$ 154,351	$ 135,687	$ (18,664)	(14%)

	DD&A Variance Due to Production	DD&A Variance Due to Rates	DD&A Variance Due to Total
Year ended December 31, 2009 compared to 2008	$ 32,098	$ (50,762)	$ (18,664)

Our average depletion rate increased by $0.13 per Mcfe, or 5%, from $2.76 per Mcfe in 2008 to $2.89 per Mcfe in 2009 due primarily to higher cost wells being drilled in the Mid-Continent region.

Impairments

The following table summarizes impairment charges recorded for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Oil and gas properties - held for sale	$ 97,400	$ -	$ (97,400)	n/a
Oil and gas properties	4,932	19,963	15,031	75%
Other - tubular inventory and well materials	4,083	-	(4,083)	n/a
	$ 106,415	$ 19,963	$ (86,452)	(433%)

During 2009, we recorded impairment charges attributable to the classification of our Gulf Coast properties in Texas and Louisiana as held for sale. This impairment represents an adjustment from the properties' carrying values to the estimated fair value less costs to sell. The sale of these properties was completed in January 2010. Other impairments of oil and gas properties reflect declines in spot and future oil and gas prices which reduced reserves on certain properties primarily in the Mid-Continent region. Other impairment charges during 2009 were attributable to the re-evaluation of our tubular inventory and well materials due to declines in market value. Impairment charges in 2008 related to declines in spot and future oil and gas prices which reduced the estimated reserve bases of fields on certain properties in the Mid-Continent and Appalachian regions. These changes in reserve estimates in 2008 were due primarily to a decrease in fourth quarter oil and gas prices.

Other

Other operating expenses in 2009 represent losses on the sale of certain excess tubular inventory and well materials that were sold in connection with the drilling program reduction.

Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Interest on borrowings and related fees	$ 33,374	$ 19,068	$ (14,306)	(75%)
Accretion of original issue discount	7,523	6,241	(1,282)	(21%)
Amortization of debt issuance costs	2,679	1,715	(964)	(56%)
Interest rate swaps	3,969	1,015	(2,954)	(291%)
Capitalized interest	(2,318)	(2,987)	(669)	(22%)
Other, net	(996)	(425)	571	134%
	$ 44,231	$ 24,627	$ (19,604)	(80%)

Interest expense increased primarily as a result of higher interest rates on outstanding borrowings, including the Senior Notes, which were issued in June 2009. In addition, we recorded higher amortization of the original issue discount and issuance costs on the Senior Notes and Convertible Notes as well as higher amortization of issuance costs associated with the Revolver. As a result of the reduced capital expenditures program in 2009, we experienced a reduction in capitalized interest.

Derivatives

The components of our derivatives income are presented below for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Oil and gas derivative unrealized derivative gain (loss)	$ (26,690)	$ 37,365	$ (64,055)	171%
Oil and gas derivative realized gain (loss)	59,908	(7,620)	67,528	(886%)
Interest rate swap unrealized gain	111	-	111	n/a
Interest rate swap realized loss	(1,761)	-	(1,761)	n/a
	$ 31,568	$ 29,745	$ 1,823	6%

Cash received for settlements during 2009 was $58.1 million as compared to cash payments of $7.6 million during 2008.

Other

Other income decreased due to lower gains on the sale of non-operating investments as well as lower interest income on cash balances.

Income Taxes

The effective tax benefit rate for 2009 was 39.6% as compared to 37.2% for 2008. Favorable settlements of uncertain tax positions resulted in a 0.5% increase in the effective tax benefit rate in 2009 and a decrease of 1.5% in the effective tax rate during 2008.

Discontinued Operations

The following table presents a summary of results of operations from discontinued operations for the periods presented:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Favorable (Unfavorable)	% Change
Revenues	$ 579,931	$ 751,361	$ (171,430)	(23%)
Income from discontinued operations before taxes	$ 64,130	$ 104,215	$ (40,085)	(38%)
Income tax expense [1]	(10,642)	(16,314)	5,672	35%
Income from discontinued operations, net of taxes	$ 53,488	$ 87,901	$ (34,413)	(39%)

[1] Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests that are fully attributable to PVG's operations.

Noncontrolling Interests

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

Liquidity and Capital Resources

Cash Flows

Since the third quarter of 2009, our working capital and capital expenditures funding requirements have been met with a combination of operating cash flows and asset sales. Our overall cash requirements will continue to be met with a combination of these sources, Revolver borrowings and supplemental issues of debt and equity as necessary. We believe that cash on hand and cash generated from our operations and our borrowing capacity will be sufficient to meet our 2011 working capital requirements, anticipated capital expenditures (other than acquisitions), scheduled debt payments and dividend payments. Our ability to satisfy our obligations and planned expenditures will depend on our future operating performance, which will be affected by, among other things, prevailing economic conditions in the commodity markets of oil and natural gas, some of which are beyond our control.

The following table summarizes our statements of cash flows for the periods presented:

	For the Year Ended December 31, 2010	2009	Variance
Cash flows from operating activities	$ 79,839	$ 117,733	$ (37,894)
Cash flows from investing activities			
Capital expenditures - property and equipment	(405,994)	(205,676)	(200,318)
Proceeds from the sale of PVG units, net	139,120	-	139,120
Proceeds from the sale of property and equipment and other, net	26,759	15,094	11,665
Net cash used in investing activities	(240,115)	(190,582)	(49,533)
Cash flows from financing activities			
Dividends paid	(10,271)	(9,836)	(435)
Distributions received from discontinued operations	11,218	42,279	(31,061)
Repayments of borrowings, net	-	(339,542)	339,542
Proceeds from the issuance of Senior Notes, net	-	291,009	(291,009)
Proceeds from the issuance of common stock, net	-	64,835	(64,835)
Proceeds from sale of PVG units, net	199,125	118,080	81,045
Debt issuance costs paid	-	(14,959)	14,959
Other, net	2,098	-	2,098
Net cash provided by financing activities	202,170	151,866	50,304
Net increase in cash and cash equivalents	$ 41,894	$ 79,017	$ (37,123)

Cash Flows From Operating Activities

Cash settlements from our derivative portfolio were lower by $25.3 million during 2010 as compared to 2009 due to higher average commodity prices. Primarily as a result of taxable gains realized upon the sale of our remaining interests in PVG during 2010, total tax payments were higher by $18.7 million compared to 2009. As a result of our organization restructuring program announced in the fourth quarter of 2009, we paid related costs of approximately $9 million during 2010. In addition, interest payments on our debt instruments were $8.9 million higher during 2010 due primarily to the Senior Notes issued in the second quarter of 2009. These items were partially offset by the absence in 2010 of approximately $20 million in rig standby charges which were incurred and paid in 2009.

Cash Flows From Investing Activities

Cash used in investing activities consisted of $406.0 million of capital expenditures, offset partially by net proceeds of $139.1 million received from the sale in June 2010 of our remaining interests in PVG and $26.8 million from the sale of non-core assets, including our Gulf Coast properties. We have expanded our drilling program in 2010 as compared to 2009. Significant cash outlays for capital projects are anticipated to continue into 2011, including exploration activities in the Eagle Ford and Marcellus Shale plays.

The following table sets forth costs related to our capital programs for the periods presented:

	Year Ended December 31, 2010	2009
Oil and gas:		
Development drilling	$ 243,446	$ 140,243
Exploration drilling	54,340	2,524
Seismic	10,168	1,195
Lease acquisitions, field projects and other	140,473	18,456
Pipeline and gathering facilities	1,407	9,382
	449,834	171,800
Other - Corporate	1,337	1,958
Total capital program costs	$ 451,171	$ 173,758

The following table reconciles the total costs of our capital programs with the net cash paid for capital expenditures for property and equipment as reported in our Consolidated Statements of Cash Flows for the periods presented:

	Year Ended December 31,	
	2010	2009
Total capital program costs	$ 451,171	$ 173,758
Less:		
Exploration expenses		
Seismic	(10,168)	(1,195)
Other, primarily delay rentals	(2,379)	(3,743)
Changes in accrued capitalized costs	(20,197)	34,126
Property received as consideration in sale transaction [1]	(8,204)	-
Add:		
Capitalized interest	1,384	2,318
Other	(5,613)	412
Total cash paid for capital expenditures	$ 405,994	$ 205,676

[1] Represents property received in Mississippi in connection with the sale of our Gulf Coast properties.

Cash Flows From Financing Activities

During April 2010, we sold 11.25 million common units of PVG for proceeds of $199.1 million, net of offering costs, which reduced our limited partner interest in PVG to 22.6%. Because we maintained a controlling financial interest in PVG until the final sale, the proceeds from these transactions are reported as cash flows from financing activities. In addition, we received $11.2 million in distributions from PVG in 2010 as well as $2.1 million from the exercise of stock options by employees.

During 2009, we issued the Senior Notes for proceeds of $281.4 million, net of discount and issuance costs, and received proceeds of $64.8 million from the issuance of 3.5 million shares of our common stock. The proceeds from these transactions were used primarily to repay borrowings under the Revolver. In addition, we received $118.1 million from the sale of 10 million common units of PVG in September 2009.

Sources of Liquidity

Debt and Credit Facilities

	As of December 31,	
	2010	2009
Revolving credit facility	$ -	$ -
Senior Notes, net of discount (principal amount of $300,000)	292,487	291,749
Convertible Notes, net of discount (principal amount of $230,000)	214,049	206,678
	$ 506,536	$ 498,427

Revolving Credit Facility. The Revolver provides for a $300 million revolving credit facility and matures in November 2012. We have the option to increase the aggregate commitments under the Revolver by up to an additional $225 million upon the receipt of additional commitments from one or more lenders. The Revolver is limited by a borrowing base calculation, and the availability under the Revolver may not exceed the lesser of the aggregate commitments or the borrowing base. As of December 31, 2010, the borrowing base, which is redetermined semi-annually, was $420 million. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions and includes a $20 million sublimit for the issuance of letters of credit.

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

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

As of December 31, 2010, there were no amounts outstanding under the Revolver, and we had available borrowing capacity of $299.3 million, net of outstanding letters of credit of $0.7 million. In addition, there were no borrowings outstanding during 2010.

Senior Notes. The Senior Notes bear interest at an annual rate of 10.375% and mature in June 2016. Interest is payable semi-annually in arrears on June 15 and December 15 of each year. The Senior Notes were sold at 97% of par, equating to an effective yield to maturity of approximately 11%. Beginning in June 2013, we may redeem all or part of the Senior Notes at a redemption price beginning at 105.188% of the principal amount and reducing to 100.0% in June 2015 and thereafter. The Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

Convertible Notes. The Convertible Notes are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment. Interest on the Convertible Notes is payable semi-annually in arrears on May 15 and November 15 of each year. Unless they are converted or repurchased earlier, the Convertible Notes will mature in November 2012.

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

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

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

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

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

Interest Rate Swaps. In December 2009, we entered into an a new interest rate swap agreement to establish variable rates on a portion of the outstanding obligation under the Senior Notes. The following table describes the terms of our interest rate swap agreement as of December 31, 2010:

	Notional	Swap Interest Rates	
Term	**Amounts**	**Pay**	**Receive**
Through June 2013	$ 100,000	3-month LIBOR + 8.175%	10.375%

Asset Dispositions

During 2009 and 2010, we completed a number of asset dispositions in addition to other debt and capital raising activities in connection with a broader effort to support funding for our capital spending program for 2010 and 2011(see Future Capital Needs and Commitments discussion that follows). The following table summarizes the net cash realized from these dispositions during the years ended December 31, 2010 and 2009:

Asset Description	Year Ended December 31, 2010	Year Ended December 31, 2009
PVG common units[1]	$ 338,245	$ 118,080
Oil and gas properties, including the Gulf Coast oil and gas assets [2]	25,567	15,083
Other	1,192	11
	$ 365,004	$ 133,174

[1] Of the total received during 2010, $199,125 has been reported as cash received from financing activities and $139,120 has been reported as cash received from investing activities.
[2] 2009 includes $2,280 received as an initial deposit in connection the with sale of the Gulf Coast properties.

As referenced in the table above, we completed the sale of our remaining Gulf Coast properties in January 2010 which completed our efforts to exit activities in this region. This sale resulted in the realization of additional net proceeds of $23.4 million in January 2010 as well as the receipt of certain oil and gas properties in Mississippi. These Gulf Coast properties were classified as “Assets held for sale” and are reflected as such on the Consolidated Balance Sheets as of December 31, 2009 (see Note 3 to the Consolidated Financial Statements).

Financial Condition

Covenant Compliance

The terms of the Revolver require us to maintain certain financial covenants as follows:

- Total debt to EBITDAX, each as defined in the Revolver, for any four consecutive quarters may not exceed 4.0 to 1.0 reducing to 3.5 to 1.0 for periods ending on or after September 30, 2011. EBITDAX, which is a non-GAAP measure, generally means net income plus interest expense, taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments, other non-cash charges or losses and the amount of cash distributions received from PVG and PVR.

- The current ratio, as of the last day of any quarter, may not be less than 1.0 to 1.0. The current ratio is generally defined as current assets to current liabilities. Current assets and current liabilities attributable to derivative instruments are also excluded. In addition, current assets include the amount of any unused commitment under the Revolver.

As of December 31, 2010 and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with the applicable covenants of the Revolver.

The following table summarizes the actual results of our covenant compliance as of and for the period ended December 31, 2010:

Description of Covenant	Required Covenant	Actual Results
Total debt to EBITDAX	< 4.0 to 1	2.2 to 1
Current ratio	> 1.0 to 1	4.7 to 1

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

Future Capital Needs and Commitments

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

In 2011, we anticipate making capital expenditures, excluding acquisitions, of approximately $320 million. The capital expenditures are expected to be funded primarily from internally generated sources of cash supplemented by Revolver borrowings. As of December 31, 2010, we had $120.9 million of cash and $299.3 million of unused borrowing capacity under the Revolver. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on industry conditions, cash flows provided by operating activities and the availability of capital.

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

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2010, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, drilling commitments, hydraulic fracturing service commitments, firm transportation agreements and letters of credit, all of which are customary in our business. See Contractual Obligations summarized below for more details related to the value of off-balance sheet arrangements. 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.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2010:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Senior Notes [1]	$ 292,487	$ -	$ -	$ -	$ 292,487
Convertible Notes [2]	214,049	-	214,049	-	-
Interest expense [3]	191,888	41,475	72,600	62,250	15,563
Asset retirement obligations [4]	7,364	-	-	-	7,364
Derivatives [5]	388	388	-	-	-
Rental commitments [6]	12,813	2,666	4,143	2,882	3,122
Firm transportation and drilling	105,127	37,045	37,826	9,086	21,170
Total contractual obligations [7]	$ 824,116	$ 81,574	$ 328,618	$ 74,218	$ 339,706

[1] Upon its maturity in June 2016, the undiscounted principal amount of $300.0 million will be due.
[2] Upon its maturity in November 2012, the undiscounted principal amount of $230.0 million will be due.
[3] Represents estimated interest payments that will be due under the Senior Notes and Convertible Notes.
[4] The undiscounted balance was approximately $33.5 million as of December 31, 2010.
[5] Represents estimated payments that we will make resulting from commodity derivatives.
[6] Primarily relates to equipment and building leases.
[7] Total contractual obligations do not include anticipated 2011 capital expenditures.

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. As of December 31, 2010, we have recorded asset retirement obligations of $7.4 million attributable to these activities. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

Critical Accounting Estimates

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

Oil and Gas Reserves

The estimates of oil and gas reserves are the single most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties subject to potential impairments. There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and 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.

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.

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 has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. At December 31, 2010, the costs attributable to unproved properties were $171.3 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 as a component of exploration expense in the aggregate over the lesser of five years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Depreciation, Depletion and Amortization

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

Derivative Activities

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

Deferred Tax Valuation Allowance

The Company records a valuation allowance to reduce its deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that the Company were to determine that it would not be able to realize all or a part of its deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of the Company’s deferred tax assets is attributable to net operating losses in certain states. Estimates of future taxable income inherently reflect a significant degree of uncertainty. During the years ended December 31, 2010 and 2009, the Company increased the valuation allowance for its deferred tax assets due primarily to its inability to project sufficient future taxable income in certain states for the parent company and certain of its subsidiaries.

New Accounting Standards

See Note 2 to the Consolidated Financial Statements for a description of recent accounting standards.

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

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risk to which we are exposed is attributable to commodity price. As a result of our risk management activities as discussed below, we are also exposed to counterparty risk with financial institutions with whom we enter into these risk management positions. Sensitivity to these risks has heightened due to the state of the global economy, including financial and credit markets.

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

At December 31, 2010, we reported a commodity derivative asset of $18.1 million. The contracts underlying such commodity derivatives are with four counterparties, all of which are investment grade financial institutions, and over 89% of such commodity derivative asset is substantially concentrated with two of these counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be approximately equal to the fair value of the contracts as of December 31, 2010. No significant uncertainties related to the collectability of amounts owed to us exist with regard to these counterparties.

In 2010, we reported consolidated net derivative gains of $41.9 million. We recognize changes in fair value in earnings currently in the Derivatives caption on our Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our commodity derivative contracts. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in natural gas, crude oil and NGL prices. These fluctuations could be significant in a volatile pricing environment. See Note 6 to the Consolidated Financial Statements for a further description of our derivatives program.

The following table sets forth our commodity derivative positions as of December 31, 2010:

	Instrument	Average Volume Per Day	Weighted Average Price Floor/Swap	Weighted Average Price Ceiling	Fair Value Asset (Liability)
Natural Gas:		**(in MMBtu)**			
First quarter 2011	Costless collars	50,000	$ 5.65	$ 8.77	$ 5,941
Second quarter 2011	Costless collars	30,000	$ 4.83	$ 6.00	1,633
Third quarter 2011	Costless collars	30,000	$ 4.83	$ 6.00	1,407
Fourth quarter 2011	Costless collars	20,000	$ 6.00	$ 8.50	2,461
First quarter 2012	Costless collars	20,000	$ 6.00	$ 8.50	1,992
Second quarter 2011	Swaps	20,000	$ 5.50		1,930
Third quarter 2011	Swaps	20,000	$ 5.50		1,703
Second quarter 2012	Swaps	10,000	$ 5.52		563
Third quarter 2012	Swaps	10,000	$ 5.52		487
Crude Oil:		**(barrels)**			
First quarter 2011	Costless collars	425	$ 80.00	$ 101.50	(10)
Second quarter 2011	Costless collars	425	$ 80.00	$ 101.50	(49)
Third quarter 2011	Costless collars	360	$ 80.00	$ 103.30	(45)
Fourth quarter 2011	Costless collars	360	$ 80.00	$ 103.30	(59)
Settlements to be paid in subsequent period					(224)

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This assumes that natural gas prices, crude oil prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of $1.00 per MMBtu of Natural Gas or $10.00 per Barrel of Crude Oil	
	Increase	**Decrease**
Effect on the fair value of natural gas derivatives	$ (14.3)	$ 15.9
Effect on the fair value of crude oil derivatives	$ (0.8)	$ 0.6
Effect on 2011 operating income, excluding natural gas derivatives	$ 38.5	$ (38.5)
Effect on 2011 operating income, excluding crude oil derivatives	$ 16.6	$ (16.6)

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2010 and 2009, 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, 2010. We also have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Penn Virginia Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting (Item 9A(b) herein). Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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, 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, 2010 and 2009, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 25, 2011

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31,		
	2010	2009	2008
Revenues			
Natural gas	$ 171,141	$ 169,666	$ 368,801
Crude oil	53,532	43,258	46,529
Natural gas liquids (NGLs)	26,663	15,735	21,292
Gain on sale of property and equipment	648	2,372	31,426
Other	2,454	4,175	1,442
Total revenues	254,438	235,206	469,490
Operating expenses			
Lease operating	35,757	44,392	51,419
Gathering, processing and transportation	14,180	11,307	8,105
Production and ad valorem taxes	13,917	15,044	22,369
General and administrative	58,383	49,690	47,477
Exploration	49,641	57,754	42,436
Depreciation, depletion and amortization	134,700	154,351	135,687
Impairments	45,959	106,415	19,963
Other	709	1,599	-
Total operating expenses	353,246	440,552	327,456
Operating income (loss)	(98,808)	(205,346)	142,034
Other income (expense)			
Interest expense	(53,679)	(44,231)	(24,627)
Derivatives	41,906	31,568	29,745
Other	2,403	1,259	2,073
Income (loss) from continuing operations before income taxes	(108,178)	(216,750)	149,225
Income tax (expense) benefit	42,851	85,894	(55,606)
Net income (loss) from continuing operations	(65,327)	(130,856)	93,619
Income from discontinued operations, net of tax	33,448	53,488	87,901
Gain on sale of discontinued operations, net of tax	51,546	-	-
Net income (loss)	19,667	(77,368)	181,520
Less net income attributable to noncontrolling interests in discontinued operations	(28,090)	(37,275)	(60,436)
Income (loss) attributable to Penn Virginia Corporation	$ (8,423)	$ (114,643)	$ 121,084
Earnings (loss) per share attributable to Penn Virginia Corporation - Basic:			
Continuing operations	$ (1.44)	$ (2.99)	$ 2.23
Discontinued operations	0.12	0.37	0.66
Gain on sale of discontinued operations	1.13	-	-
Net income (loss)	$ (0.19)	$ (2.62)	$ 2.89
Earnings (loss) per share attributable to Penn Virginia Corporation - Diluted:			
Continuing operations	$ (1.44)	$ (2.99)	$ 2.22
Discontinued operations	0.12	0.37	0.65
Gain on sale of discontinued operations	1.13	-	-
Net income (loss)	$ (0.19)	$ (2.62)	$ 2.87
Weighted average shares outstanding, basic	45,553	43,811	41,760
Weighted average shares outstanding, diluted	45,553	43,811	42,031

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	As of December 31, 2010		As of December 31, 2009	
Assets				
Current assets				
Cash and cash equivalents	$	120,911	$	79,017
Accounts receivable, net of allowance for doubtful accounts		72,378		43,157
Derivative assets		16,818		16,241
Assets held for sale		-		38,282
Other current assets		4,233		15,437
Current assets of discontinued operations		-		107,108
Total current assets		214,340		299,242
Property and equipment, net (successful efforts method)		1,705,584		1,479,452
Derivative assets		3,889		2,346
Other assets		20,787		24,124
Noncurrent assets of discontinued operations		-		1,083,343
Total assets	$	1,944,600	$	2,888,507
Liabilities and Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	$	99,661	$	70,724
Derivative liabilities		388		4,896
Deferred income taxes		4,318		-
Income taxes payable		2,627		-
Current liabilities of discontinued operations		-		77,915
Total current liabilities		106,994		153,535
Other liabilities		19,958		20,711
Derivative liabilities		-		2,460
Deferred income taxes		330,836		328,238
Long-term debt		506,536		498,427
Noncurrent liabilities of discontinued operations		-		647,137
Commitments and contingencies (Note 13)				
Shareholders' equity:				
Preferred stock of $100 par value – 100,000 shares authorized; none issued		-		-
Common stock of $0.01 par value – 128,000,000 shares authorized; shares issued of 45,556,854 and 45,386,004 as of December 31, 2010 and December 31, 2009, respectively		267		265
Paid-in capital		680,981		590,846
Retained earnings		300,473		319,167
Deferred compensation obligation		2,743		2,423
Accumulated other comprehensive loss		(938)		(1,286)
Treasury stock – 125,357 and 113,858 shares of common stock, at cost, as of December 31, 2010 and December 31, 2009, respectively		(3,250)		(3,327)
Total Penn Virginia Corporation shareholders' equity		980,276		908,088
Noncontrolling interests in discontinued operations		-		329,911
Total shareholders' equity		980,276		1,237,999
Total liabilities and shareholders' equity	$	1,944,600	$	2,888,507

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2010	**2009**	**2008**
Cash flows from operating activities			
Net income (loss)	$ 19,667	$ (77,368)	$ 181,520
Adjustments to reconcile net income (loss) to net cash provided by operating activities from continuing operations:			
Income from discontinued operations	(36,832)	(64,130)	(104,215)
Gain on sale of discontinued operations	(86,662)	-	-
Depreciation, depletion and amortization	134,700	154,351	135,687
Impairments	45,959	106,415	19,963
Derivative contracts:			
Net gains	(41,906)	(28,033)	(29,745)
Cash settlements	32,818	58,147	(7,620)
Deferred income taxes (benefit)	42,528	(83,222)	58,551
Loss (gain) on the sale of property and equipment, net	61	(1,910)	(31,426)
Dry hole and unproved leasehold expense	36,275	33,278	35,847
Non-cash interest expense	11,984	10,202	7,006
Share-based compensation	7,811	9,127	5,959
Other, net	(209)	683	(1,864)
Changes in operating assets and liabilities:			
Accounts receivable, net	(19,964)	33,266	23,811
Other current assets	2,627	960	(19,879)
Accounts payable and accrued expenses	10,877	(20,066)	(24,441)
Other assets and liabilities	(79,895)	(13,967)	(2,567)
Net cash provided by operating activities from continuing operations	79,839	117,733	246,587
Cash flows from investing activities			
Capital expenditures - property and equipment	(405,994)	(205,676)	(547,058)
Proceeds from the sale of PVG units, net (Note 3)	139,120	-	-
Proceeds from the sale of property and equipment, net	25,567	15,083	32,521
Other, net	1,192	11	-
Net cash used in investing activities for continuing operations	(240,115)	(190,582)	(514,537)
Cash flows from financing activities			
Dividends paid	(10,271)	(9,836)	(9,398)
Distributions received from discontinued operations	11,218	42,279	44,018
Repayments of short-term borrowings	-	(7,542)	7,542
Proceeds from revolving credit facility borrowings	-	87,000	273,000
Repayment of revolving credit facility borrowings	-	(419,000)	(63,000)
Proceeds from issuance of Senior Notes, net	-	291,009	-
Proceeds from the issuance of common stock, net	-	64,835	-
Proceeds from the sale of PVG units, net (Note 3)	199,125	118,080	-
Debt issuance costs paid	-	(14,959)	-
Other, net	2,098	-	11,764
Net cash provided by financing activities from continuing operations	202,170	151,866	263,926
Cash flows from discontinued operations			
Net cash provided by operating activities	77,759	158,214	137,187
Net cash used in investing activities	(18,112)	(80,506)	(318,865)
Net cash (used in) provided by financing activities	(59,647)	(77,708)	181,678
Net cash provided by discontinued operations	-	-	-
Net increase (decrease) in cash and cash equivalents	41,894	79,017	(4,024)
Cash and cash equivalents - beginning of period	79,017	-	4,024
Cash and cash equivalents - end of period	$ 120,911	$ 79,017	$ -
Supplemental disclosures:			
Cash paid for:			
Interest (net of amounts capitalized)	$ 43,531	$ 34,640	$ 19,962
Income taxes (net of refunds received)	$ 28,184	$ 9,443	$ 15,228

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS’ EQUITY AND COMPREHENSIVE INCOME
(in thousands)

	Common Shares Outstanding	Common Stock	Paid-in Capital	Retained Earnings	Deferred Compensation Obligation	Accumulated Other Comprehensive Loss	Treasury Stock	Total Penn Virginia Shareholders' Equity	Noncontrolling Interests	Total Shareholders' Equity
Balance as of December 31, 2007	41,408	$ 225	$ 408,714	$ 331,960	$ 1,608	$ (3,194)	$ (2,020)	$ 737,293	$ 174,420	$ 911,713
Net income	-	-	-	121,084	-	-	-	121,084	60,436	181,520
Change in hedging derivative financial instruments	-	-	-	-	-	(1334)	-	(1,334)	2,298	964
Change in pension and postretirement obligations	-	-	-	-	-	346	-	346	-	346
Total comprehensive income								120,096	62,734	182,830
Dividends paid ($0.225 per share)	-	-	-	(9,398)	-	-	-	(9,398)	-	(9,398)
Common stock issued as compensation	40	-	49	-	-	-	(663)	(614)	-	(614)
Share-based compensation	-	-	5,909	-	-	-	-	5,909	-	5,909
Deferred compensation	-	-	-	-	629	-	-	629	-	629
Exercise of stock options	423	5	11,722	-	-	-	-	11,727	-	11,727
Issuance of subsidiary units	-	-	-	-	-	-	-	-	138,141	138,141
Sale of subsidiary units, net of tax	-	-	60,764	-	-	-	-	60,764	(39,723)	21,041
Subsidiary units transferred as consideration	-	-	-	-	-	-	-	-	23,469	23,469
Unit-based compensation of subsidiaries	-	-	509	-	-	-	-	509	2,431	2,940
Distributions to noncontrolling interest holders	-	-	-	-	-	-	-	-	(64,245)	(64,245)
Other	-	-	(1,700)	-	-	-	-	(1,700)	-	(1,700)
Balance as of December 31, 2008	$ 41,871	$ 230	$ 485,967	$ 443,646	$ 2,237	$ (4,182)	$ (2,683)	$ 925,215	$ 297,227	$ 1,222,442
Net income (loss)	-	-	-	(114,643)	-	-	-	(114,643)	37,275	(77,368)
Change in hedging derivative financial instruments	-	-	-	-	-	2,756	-	2,756	1,048	3,804
Change in pension and postretirement obligations	-	-	-	-	-	140	-	140	-	140
Total comprehensive income (loss)								(111,747)	38,323	(73,424)
Dividends paid ($0.225 per share)	-	-	-	(9,836)	-	-	-	(9,836)	-	(9,836)
Issuance of common stock	3,500	35	64,800	-	-	-	-	64,835	-	64,835
Common stock issued as compensation	3	-	60	-	-	-	-	60	-	60
Share-based compensation	-	-	9,062	-	-	-	-	9,062	-	9,062
Deferred compensation	12	-	11	-	186	-	(258)	(61)	-	(61)
Exercise of stock options	-	-	367	-	-	-	(386)	(19)	-	(19)
Sale of subsidiary units, net of tax (Notes 3 and 14)	-	-	32,739	-	-	-	-	32,739	67,713	100,452
Unit-based compensation of subsidiaries	-	-	(833)	-	-	-	-	(833)	4,819	3,986
Distributions to noncontrolling interest holders	-	-	-	-	-	-	-	-	(78,171)	(78,171)
Other	-	-	(1,327)	-	-	-	-	(1,327)	-	(1,327)
Balance as of December 31, 2009	45,386	$ 265	$ 590,846	$ 319,167	$ 2,423	$ (1,286)	$ (3,327)	$ 908,088	$ 329,911	$ 1,237,999
Net income (loss)	-	-	-	(8,423)	-	-	-	(8,423)	28,090	19,667
Change in hedging derivative financial instruments	-	-	-	-	-	-	-	-	582	582
Change in pension and postretirement obligations	-	-	-	-	-	348	-	348	-	348
Total comprehensive income								(8,075)	28,672	20,597
Dividends paid ($0.225 per share)	-	-	-	(10,271)	-	-	-	(10,271)	-	(10,271)
Common stock issued as compensation	5	-	92	-	-	-	-	92	-	92
Share-based compensation	(2)	-	7,157	-	-	-	-	7,157	-	7,157
Deferred compensation	8	-	562	-	320	-	(309)	573	-	573
Exercise of stock options	136	1	1,712	-	-	-	386	2,099	-	2,099
Phantom unit vesting	24	1	201	-	-	-	-	202	-	202
Sale of subsidiary units, net of tax (Notes 3 and 14)	-	-	82,915	-	-	-	-	82,915	70,188	153,103
Deconsolidation of subsidiaries (Notes 3, 4 and 14)	-	-	-	-	-	-	-	-	(382,325)	(382,325)
Unit-based compensation of subsidiaries	-	-	(1,267)	-	-	-	-	(1,267)	3,120	1,853
Distributions to noncontrolling interest holders	-	-	-	-	-	-	-	-	(49,566)	(49,566)
Other	-	-	(1,237)	-	-	-	-	(1,237)	-	(1,237)
Balance as of December 31, 2010	$ 45,557	$ 267	$ 680,981	$ 300,473	$ 2,743	$ (938)	$ (3,250)	$ 980,276	$ -	$ 980,276

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company primarily engaged in the exploration, development and production of natural gas and oil in various domestic onshore regions including Texas, Appalachia, the Mid-Continent and Mississippi.

Prior to June 2010, we indirectly owned partner interests in Penn Virginia Resource Partners, L.P. ("PVR"), a publicly traded limited partnership formed by us in 2001 that is engaged in the coal and natural resource management and natural gas midstream businesses. Our ownership interests in PVR were held principally through our general and limited partner interests in Penn Virginia GP Holdings, L.P. ("PVG"), a publicly traded limited partnership formed by us in 2006. In June 2010, we disposed of our remaining ownership interests in PVG and, indirectly, our interests in PVR. The disposition, as well as related transactions that took place earlier in 2010 and 2009, are more fully described in Note 3.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

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

Cash and Cash Equivalents

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

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 has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

Depreciation, depletion and amortization ("DD&A") of proved producing properties is computed using the units-of-production method. Oil and natural gas liquids ("NGLs") are converted to a gas equivalent on the basis that one barrel of liquids is equivalent to six thousand cubic feet of natural gas. Historically, we have adjusted our depletion rate throughout the year as new data becomes available and in the fourth quarter based on the year-end reserve report.

Impairment of Long-Lived and Other Assets

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

We review oil and gas properties for impairment periodically 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. Performing the impairment evaluations requires use of judgments and estimates since the results are dependent on future events. Such events include estimates of proved and possible reserves, future commodity prices and the timing of future production and capital expenditures, among others. We have recognized impairments of our properties in 2010, 2009 and 2008, as described in Note 17. We cannot predict whether impairment charges will be required in the future.

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. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results. 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 and the amortization is charged to exploration expense.

Other Property and Equipment

Other property and equipment consist primarily of gathering systems and related equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

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

	Useful Life
Gathering systems	15-20 years
Other property and equipment	3-20 years

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in the 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. 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 deferred tax assets is assessed periodically and is dependent upon the generation of future taxable income and our ability to utilize tax credits and operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent they arise, as a component of interest expense and penalties as a component of income tax expense.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation (“ARO”) in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and natural gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in DD&A expense on our Consolidated Statements of Income.

Derivative Instruments

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

We recognize changes in fair value in earnings currently as a component of the Derivatives caption on the Consolidated Statements of Income. We have experienced and could continue to experience significant changes in the amount of unrealized derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts, which fluctuate with changes in natural gas and crude oil prices.

Revenue Recognition

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

Share-Based Compensation

We have several stock compensation plans that allow incentive and nonqualified stock options, restricted stock and restricted stocks units to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. We measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Recent Accounting Standards

In January 2010, the Financial Accounting Standards Board issued guidance on increased fair-value measurement disclosures. The guidance requires us to make new disclosures about recurring or nonrecurring fair-value measurements, including significant transfers into and out of level 1 and level 2 fair-value measurements and information on purchases, sales, issuances and settlements on a gross basis in the reconciliation of level 3 fair-value measurements. The guidance also clarified existing fair-value measurement disclosure about the level of disaggregation, inputs and valuation techniques. Except for the detail level 3 roll forward disclosures this guidance is effective for annual and interim reporting beginning in the first quarter of 2010. The new disclosures about purchases, sales, issuances and settlements in the roll forward activity for level 3 fair-value measurements are effective for interim and annual reporting beginning in the first quarter of 2011. The Company adopted the provisions of the guidance during the first quarter of 2010 with no significant impact on its fair-value measurement disclosures. In addition, the Company does not anticipate any significant impact from the required level 3 roll-forward disclosures effective in 2011.

Reclassifications

As a result of the disposition of our interests in PVG, the presentation of our Consolidated Financial Statements and Notes is substantially different in format from previous annual filings due primarily to the reporting of PVG as discontinued operations. In addition, certain amounts for the 2009 and 2008 periods have been reclassified to conform to the current year presentation.

Subsequent Events

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

3. Acquisitions and Divestitures

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

Property Acquisitions

Eagle Ford and Marcellus Shale Property Acquisitions

In August 2010, we acquired approximately 6,800 net acres in the Eagle Ford Shale play in Texas for approximately $31.1 million. The acreage includes over 40 potential horizontal well locations. We are the operator with a working interest of approximately 75% and a net revenue interest of approximately 57%. During 2010, we acquired a total of approximately 27,000 net acres in the Marcellus Shale play in Pennsylvania for approximately $69 million bringing our holdings in the area to approximately 56,000 net acres as of December 31, 2010.

Divestitures

PVG Unit Offerings

In September 2009, we sold 10 million common units of PVG ("PVG Common Units") owned by us for proceeds of $118.1 million, net of offering costs, resulting in a reduction of our limited partner interest in PVG from 77.0% to 51.4%. In April 2010, we completed the sale of an additional 11.25 million PVG Common Units for proceeds of $199.1 million, net of offering costs, which further reduced our limited partner interest to 22.6%. On a combined basis, these transactions resulted in a $137.9 million increase to noncontrolling interests as well as a $115.7 million increase to additional paid-in capital, net of income tax effects. Because we maintained a controlling financial interest in PVG, the proceeds received from these transactions were reported as cash flows from financing activities on our Consolidated Statements of Cash Flows.

In June 2010, we completed the sale of our remaining PVG Common Units for $139.1 million, net of offering costs. Immediately prior to the closing of the June offering, we contributed 100% of the membership interests in PVG's general partner to PVG, thereby relinquishing control of PVG. As a result of this divestiture, we recognized a gain of $51.5 million, net of income tax effects of $35.1 million, which is reported in the "Gain on sale of discontinued operations, net of tax" caption on our Consolidated Statements of Income. Because we no longer held any interests in PVG, the proceeds received from this transaction were reported as cash flows from investing activities on our Consolidated Statements of Cash Flows and we deconsolidated PVG from our Consolidated Financial Statements. We have reported PVG's results of operations and financial position as discontinued operations for the 2010 periods and comparative 2009 and 2008 periods. Additional information with respect to discontinued operations is provided in Note 4.

Gulf Coast Properties

In December 2009, we entered into purchase and sale agreements with a private company (the "Counterparty") which resulted in the disposition of all of our oil and gas properties in the Gulf Coast region (southern Texas and Louisiana) in January 2010 for cash proceeds of $23.4 million, net of transaction costs and purchase and sale adjustments, and the exchange of certain oil and gas properties located in the Gwinville field in northern Mississippi valued at $8.2 million. The fair values of the Gulf Coast oil and gas properties, as well as liabilities attributable to the disposal group, were reported as assets and liabilities held for sale as of December 31, 2009. The fair value of the properties received from the Counterparty in the exchange was $8.2 million. An initial deposit of $2.3 million was received from the Counterparty in December 2009. This amount was included in accrued liabilities as of December 31, 2009.

Other Properties

During 2010, we received net proceeds of $2.0 million from the sale of various oil and gas properties located in North Dakota, West Virginia and Oklahoma. In July 2008, we sold certain unproved oil and gas acreage in Louisiana for cash proceeds of $32 million and recognized a $30.5 million gain on that sale. The $30.5 million gain on the sale is reported in the revenues section of our Consolidated Statements of Income.

The following table reflects the fair values of items held for sale for the periods presented:

	As of December 31,	
	2010	**2009**
Assets held for sale		
Fair value of oil and gas properties	$ -	$ 38,282
Liabilities held for sale		
Asset retirement obligation	$ -	$ 500

4. Discontinued Operations

Income from discontinued operations represents the results of operations of PVG, which include the results of operations of PVR. Previously, the results of operations of PVG and PVR were presented as our coal and natural resource management and natural gas midstream segments. The disclosures for the 2010 period provided in the table below reflect the results of operations of PVG through the date of the disposition of our entire remaining interest in PVG on June 7, 2010.

	Year Ended December 31,		
	2010	**2009**	**2008**
Revenues	$ 303,206	$ 579,931	$ 751,361
Income from discontinued operations before taxes	$ 36,832	$ 64,130	$ 104,215
Income tax expense [1]	(3,384)	(10,642)	(16,314)
Income from discontinued operations, net of taxes	$ 33,448	$ 53,488	$ 87,901

[1] Determined by applying the effective tax rate attributable to discontinued operations to the income from discontinued operations less noncontrolling interests that are fully attributable to PVG's operations.

The following tables provide the detail of the assets and liabilities of discontinued operations as of December 31, 2009:

Current assets:			Noncurrent assets:		
Cash and cash equivalents	$	19,314	Net property and equipment	$	872,906
Accounts receivable, net		81,647	Equity investments		87,601
Derivative assets		1,331	Intangibles, net		83,741
Inventory		1,832	Derivative assets		1,284
Other current assets		2,984	Other noncurrent assets		37,811
	$	107,108		$	1,083,343

Current liabilities:			Noncurrent liabilities:		
Accounts payable	$	52,901	Other liabilities	$	22,752
Accrued liabilities		13,763	Derivative liabilities		4,285
Derivative liabilities		11,251	Long-term debt of PVR		620,100
	$	77,915		$	647,137

The following table summarizes the determination of the gain recognized on the disposition of PVG:

Cash proceeds, net of offering costs (8,827,429 units x $15.76 per unit)	$	139,120
Carrying value of noncontrolling interests in PVG at date of disposition		382,324
		521,444
Less: Carrying value of PVG's assets and liabilities at date of disposition		(434,782)
		86,662
Income tax expense		(35,116)
Gain on sale of discontinued operations, net of tax	$	51,546

PVR will continue to provide marketing and gas gathering and processing services to the Company under a number of existing agreements with various remaining terms. We will continue to sell gas to PVR for resale at PVR's Crossroads plant in Texas. In addition, we and PVG entered into transition service agreements attributable primarily to corporate and information technology functions which extend through March 31, 2011. Through December 31, 2010, we have billed PVG for transition services in the amount of $0.7 million, net of amounts charged to us by PVG. These amounts are included in the General and administrative caption on our Consolidated Statements of Income as a reduction to expenses.

5. Accounts Receivable

The following table summarizes our accounts receivable by type for the periods presented:

	As of December 31,			
	2010		2009	
Customers	$	44,783	$	31,386
Joint interest partners		23,526		9,414
Other		4,442		3,485
		72,751		44,285
Less: Allowance for doubtful accounts		(373)		(1,128)
	$	72,378	$	43,157

As of December 31, 2010, no receivables were collateralized.

For the years ended December 31, 2010 and 2009, four customers accounted for $148.5 million and $120.1 million, or approximately 59% and 53%, respectively, of our total consolidated product revenues. As of December 31, 2010 and 2009, $29.0 million and $19.0 million, or approximately 40% and 44%, respectively, of our consolidated accounts receivable, including joint interest billings, related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by these customers.

6. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to natural gas and crude oil price volatility as well as the volatility in interest rates attributable to our debt instruments. The derivative instruments, which are placed with financial institutions that we believe are acceptable credit risks, generally take the form of costless collars and swaps. Our derivative instruments are not designated as hedges.

Commodity Derivatives

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

The counterparty to a collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. The counterparty to a swap contract is required to make a payment to us if the settlement price for any settlement period is greater than the swap price for such contracts, and we are required to make a payment to the counterparty if the settlement price is less than the swap price for such contract.

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

The following table sets forth our commodity derivative positions as of December 31, 2010:

	Instrument	Average Volume Per Day	Weighted Average Price		Fair Value Asset (Liability)
			Floor/Swap	Ceiling	
Natural Gas:		**(in MMBtu)**			
First quarter 2011	Costless collars	50,000	$ 5.65	$ 8.77	$ 5,941
Second quarter 2011	Costless collars	30,000	$ 4.83	$ 6.00	1,633
Third quarter 2011	Costless collars	30,000	$ 4.83	$ 6.00	1,407
Fourth quarter 2011	Costless collars	20,000	$ 6.00	$ 8.50	2,461
First quarter 2012	Costless collars	20,000	$ 6.00	$ 8.50	1,992
Second quarter 2011	Swaps	20,000	$ 5.50		1,930
Third quarter 2011	Swaps	20,000	$ 5.50		1,703
Second quarter 2012	Swaps	10,000	$ 5.52		563
Third quarter 2012	Swaps	10,000	$ 5.52		487
Crude Oil:		**(barrels)**			
First quarter 2011	Costless collars	425	$ 80.00	$ 101.50	(10)
Second quarter 2011	Costless collars	425	$ 80.00	$ 101.50	(49)
Third quarter 2011	Costless collars	360	$ 80.00	$ 103.30	(45)
Fourth quarter 2011	Costless collars	360	$ 80.00	$ 103.30	(59)
Settlements to be paid in subsequent period					(224)

Interest Rate Swaps

In 2006, we entered into interest rate swaps (“Previous Interest Rate Swaps”) with notional amounts of $50 million to establish fixed interest rates on a portion of the then outstanding borrowings under our revolving credit facility (“Revolver”) through December 2010. During the first quarter of 2009, we discontinued hedge accounting for all of the Previous Interest Rate Swaps. Accordingly, subsequent fair value gains and losses for the Previous Interest Rate Swaps have been recognized in the Derivatives caption on our Consolidated Statements of Income.

As there are currently no amounts outstanding under the Revolver, we entered into an offsetting fixed-to-floating interest rate swap in December 2009 that effectively unwinds the Previous Interest Rate Swaps.

In December 2009, we entered into a new interest rate swap agreement to establish variable rates on approximately one-third of the face amount of the outstanding obligation under the 10.375% Senior Unsecured Notes ("Senior Notes").

The following table sets forth the terms and positions of our interest rate swaps for the periods presented:

Term	Notional Amount	Swap Interest Rates [1] Pay	Swap Interest Rates [1] Receive	Fair Value as of December 31, 2010	Fair Value as of December 31, 2009
Through December 2010	$ 50,000	5.349 %	LIBOR	$ -	$ (2,375)
Through December 2010	$ 50,000	LIBOR	0.53 %	-	(39)
Through June 2013	$ 100,000	LIBOR + 8.175%	10.375 %	2,590	(872)

[1] References to LIBOR represent the 3-month rate.

Financial Statement Impact of Derivatives

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

Derivatives not designated as hedging instruments:	**Location of gain (loss) recognized in income**	**Year Ended December 31, 2010**	**2009**	**2008**
Interest rate contracts [1]	Interest expense	$ -	$ (3,864)	$ (1,015)
Interest rate contracts	Derivatives	5,213	(1,650)	-
Commodity contracts	Derivatives	36,693	33,218	29,745
Total increase (decrease) in net income resulting from derivatives		$ 41,906	$ 27,704	$ 28,730
Realized and unrealized derivative impact:				
Cash received for commodity and interest rate contract settlements	Derivatives	$ 32,818	$ 58,147	$ (7,620)
Cash paid for interest rate contract settlements	Interest expense	-	(438)	(1,015)
Unrealized derivative gain (loss) [2]		9,088	(30,005)	37,365
Total increase (decrease) in net income resulting from derivatives		$ 41,906	$ 27,704	$ 28,730

[1] This represents interest rate swap amounts reclassified out of Accumulated other comprehensive income ("AOCI") and into earnings. During 2009 and 2008, the Company discontinued hedge accounting for the Previous Interest Rate Swaps. A total of $3.9 million and $1.0 million for remaining AOCI and actual hedge settlements for 2009 and 2008 were reclassified into earnings in the same periods relating to the Previous Interest Rate Swaps not designated for hedge accounting.

[2] Represents unrealized gains (losses) in the Interest expense and Derivatives caption on our Condensed Consolidated Statements of Income.

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

		Fair Values as of			
		December 31, 2010		December 31, 2009	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Interest rate contracts	Derivative assets/liabilities - current	$ 1,743	$ -	$ 1,463	$ 2,413
Commodity contracts	Derivative assets/liabilities - current	15,075	388	14,778	2,483
		16,818	388	16,241	4,896
Interest rate contracts	Derivative assets/liabilities - noncurrent	847	-	-	2,334
Commodity contracts	Derivative assets/liabilities - noncurrent	3,042	-	2,346	126
		3,889	-	2,346	2,460
		$ 20,707	$ 388	$ 18,587	$ 7,356

At December 31, 2010, we reported a commodity derivative asset of $18.1 million, over 89% of which was concentrated with two counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that this counterparty may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties exist related to the collectability of amounts owed to us by these counterparties.

The effects of derivative gains (losses) and cash settlements of our oil and gas commodity derivatives are reported as adjustments to reconcile net income to net cash provided by operating activities on our Consolidated Statements of Cash Flows. These items are recorded in the Derivative contracts — Cash settlements caption on the Consolidated Statements of Cash Flows.

As of December 31, 2010, we had not actively traded derivative instruments.

7. Property and Equipment

The following table summarizes our property and equipment for the periods presented:

	As of December 31,	
	2010	2009
Oil and gas properties:		
Proved	$ 2,139,894	$ 1,887,073
Unproved	171,303	73,067
Total oil and gas properties	2,311,197	1,960,140
Other property and equipment	15,589	15,903
Total property and equipment	2,326,786	1,976,043
Accumulated depreciation, depletion and amortization	(621,202)	(496,591)
	$ 1,705,584	$ 1,479,452

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

	2010		2009		2008	
	Number of Wells	Cost	Number of Wells	Cost	Number of Wells	Cost
Balance at beginning of year	-	$ -	1	$ 2,482	4	$ 4,336
Additions pending determination of proved reserves	1	6,180	-	-	1	2,482
Reclassification to wells, equipment and facilities based on the determination of proved reserves	-	-	(1)	(2,482)	-	-
Charged to exploration expense	-	-	-	-	(4)	(4,336)
Balance at end of year	1	$ 6,180	-	$ -	1	$ 2,482

8. Long-Term Debt

The following table summarizes our long-term debt for the periods presented:

	As of December 31, 2010	As of December 31, 2009
Revolving credit facility	$ -	$ -
Senior notes, net of discount (principal amount of $300,000)	292,487	291,749
Convertible notes, net of discount (principal amount of $230,000)	214,049	206,678
	$ 506,536	$ 498,427

Revolving Credit Facility

The Revolver provides for a $300 million revolving credit facility and matures in November 2012. We have the option to increase the aggregate commitments under the Revolver by up to an additional $225 million upon the receipt of additional commitments from one or more lenders. The Revolver is governed by a borrowing base calculation and the availability under the Revolver may not exceed the lesser of the aggregate commitments or the borrowing base. As of December 31, 2010, the borrowing base, which is redetermined semi-annually, was $420 million.

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

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries (“Guarantor Subsidiaries”). The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

As of December 31, 2010, there were no amounts outstanding under the Revolver, and we had available borrowing capacity of $299.3 million, net of outstanding letters of credit of $0.7 million. In addition, there were no borrowings outstanding during the year ended December 31, 2010.

Senior Notes

The Senior Notes, which mature in June 2016, were originally sold at 97% of par, equating to an effective yield to maturity of approximately 11%. The Senior Notes bear interest at an annual rate of 10.375% and interest is payable semi-annually in arrears on June 15 and December 15 of each year. Beginning in June 2013, we may redeem all or part of the Senior Notes at a redemption price beginning at 105.188% of the principal amount and reducing to 100.0% in June 2015 and thereafter. The Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

As of December 31, 2010, approximately 98% of our consolidated assets were held by the Guarantor Subsidiaries with the remainder being held by our parent company, which is the issuer of the Senior Notes. The parent company incurs operating expenses in connection with the administration of its investment in its operating subsidiaries and incurs interest expense and related borrowing costs attributable to the Senior Notes and the 4.5% Convertible Notes (“Convertible Notes”). Accordingly, the parent company has no independent operations. There are no significant restrictions on the ability of the parent company or any of the Guarantor Subsidiaries to obtain funds through dividends or other means, including advances and intercompany notes among others.

Convertible Notes

The Convertible Notes, which mature in November 2012, are convertible into cash up to the principal amount thereof and shares of our common stock, if any, in respect of the excess conversion value, based on an initial conversion rate of 17.3160 shares of common stock per $1,000 principal amount of the Convertible Notes (which is equal to an initial conversion price of approximately $57.75 per share of common stock), subject to adjustment.

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

	As of December 31,	
	2010	2009
Principal	$ 230,000	$ 230,000
Unamortized discount	(15,951)	(23,322)
Net carrying amount of liability component	$ 214,049	$ 206,678
Carrying amount of equity component	$ 36,850	$ 36,850

The unamortized discount will be amortized through the end of 2012. The effective interest rate on the liability component of the Convertible Notes for the years ended December 31, 2010 and 2009 was 8.5%. During each of the three years ended December 31, 2010, we recognized interest expense of $10.4 million, respectively, related to the contractual coupon rate on the Convertible Notes. In addition, we recognized $7.4 million, $6.8 million and $6.2 million of interest expense related to the amortization of the discount for the years ended December 31, 2010, 2009 and 2008, respectively.

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

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

We also entered into separate warrant transactions ("Warrants"), whereby we sold to the Option Counterparties warrants to acquire, subject to anti-dilution adjustments, approximately 3,982,680 shares of our common stock at a strike price of $74.25 per share. Upon exercise of the Warrants, we will deliver shares of our common stock equal in value to the excess of the then market price over the strike price of the Warrants.

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

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

Debt Maturities

The following table sets forth the aggregate maturities of the principal amounts of our long-term debt for the next five years and thereafter:

Year	Amounts
2011	$ -
2012	214,049
2013	-
2014	-
2015	-
Thereafter	292,487
Total	$ 506,536

9. Income Taxes

The following table summarizes our provision for income taxes from continuing operations for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Current income taxes (benefit)			
Federal	$ (109,240)	$ (2,158)	$ (951)
State	876	(514)	(1,994)
	(108,364)	(2,672)	(2,945)
Deferred income taxes (benefit)			
Federal	67,999	(68,488)	48,617
State	(2,486)	(14,734)	9,934
	65,513	(83,222)	58,551
	$ (42,851)	$ (85,894)	$ 55,606

The following table summarizes the intra-period allocation of income taxes for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Continuing operations	$ (42,851)	$ (85,894)	$ 55,606
Discontinued operations	3,384	10,642	16,314
Gain on sale of discontinued operations	35,116	-	-
	$ (4,351)	$ (75,252)	$ 71,920

The following table reconciles the difference between the taxes computed by applying the statutory tax rate to income from continuing operations before income taxes and our reported income tax expense for the periods presented:

	Year Ended December 31,					
	2010		2009		2008	
Computed at federal statutory rate	$ (37,862)	(35.0)%	$ (75,863)	(35.0)%	$ 52,229	35.0%
State income taxes, net of federal income tax benefit	(1,927)	(1.8)%	(8,020)	(3.7)%	5,671	3.8%
Other, net	(3,062)	(2.8)%	(2,011)	(0.9)%	(2,294)	(1.5)%
	$ (42,851)	(39.6)%	$ (85,894)	(39.6)%	$ 55,606	37.3%

The following table summarizes the principal components of our net deferred income tax liability for the periods presented:

	As of December 31, 2010	2009
Deferred tax liabilities:		
Property and equipment	$ 352,431	$ 347,627
Fair value of derivative instruments	2,215	-
Convertible notes	6,143	9,027
Other	-	11,683
Total deferred tax liabilities	360,789	368,337
Deferred tax assets:		
Fair value of derivative instruments	-	9,194
Deferred income	-	9,069
Pension and postretirement benefits	3,951	4,096
Stock-based compensation	7,602	5,349
Net operating loss carryforwards	27,915	1,806
Other	5,230	12,768
	44,698	42,282
Less: Valuation allowance	(19,063)	(885)
Total deferred tax assets	25,635	41,397
Net deferred tax liability	$ 335,154	$ 326,940

As of December 31, 2010 and 2009, valuation allowances of $19.1 million and $0.9 million, respectively, had been recorded for deferred tax assets associated with state net operating loss carryovers that were not more likely than not to be realized. The net operating losses, if unused, will begin to expire starting in 2011. Due to the geographical scope of our operations, we are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

The Company has no liability for unrecognized tax benefits as of December 31, 2010 and 2009. The liability for unrecognized tax benefits at December 31, 2008 included $3.3 million of tax positions which, when settled, changed the effective tax rate in 2009. For the year ended December 31, 2010, there were no interest and penalty charges recognized. For the years ended December 31, 2009 and 2008, we recognized $2.1 million and $3.7 million in interest and penalties. Tax years from 2007 forward remain open for examination by the Internal Revenue Service.

A reconciliation of our unrecognized tax benefits for the periods presented is provided as follows:

	Year Ended December 31, 2010	2009	2008
Balance at beginning of year	$ -	$ 4,600	$ 9,852
Additions as a result of tax positions taken in the current year	-	78	220
Additions as a result of tax positions taken in prior years	-	100	461
Settlements	-	(4,778)	(5,933)
Balance at end of year	-	-	4,600
Less: current portion	-	-	(1,800)
Long-term portion	$ -	$ -	$ 2,800

10. Asset Retirement Obligations

The following table reconciles our AROs for the periods presented, which are included in the Other liabilities caption on our Consolidated Balance Sheets:

	As of December 31, 2010	As of December 31, 2009
Balance at beginning of year	$ 6,835	$ 6,775
Liabilities incurred	126	203
Liabilities settled	(41)	(142)
Transfers	-	(500)
Accretion expense	444	499
Balance at end of year	$ 7,364	$ 6,835

11. Additional Balance Sheet Detail

The following tables summarize components of selected balance sheet accounts for the periods presented:

	As of December 31, 2010	As of December 31, 2009
Other current assets:		
Tubular inventory and well materials	$ 3,600	$ 10,372
Prepaid expenses	633	1,540
Deferred income taxes	-	1,298
Income tax receivable	-	2,227
	$ 4,233	$ 15,437
Other assets:		
Debt issuance costs	$ 14,300	$ 18,175
Long-term investments - SERP	6,440	5,904
Other	47	45
	$ 20,787	$ 24,124
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 33,831	$ 26,269
Drilling costs	31,770	11,203
Royalties	9,308	6,397
Production and franchise taxes	6,012	8,209
Compensation	9,631	8,311
Interest	2,977	2,771
Gas imbalance	1,199	1,094
Deposit received on properties sold	-	2,280
Other	4,933	4,190
	$ 99,661	$ 70,724
Other liabilities:		
Asset retirement obligation	$ 7,364	$ 6,835
Pension	1,766	1,762
Postretirement health care	2,976	3,452
Deferred compensation	6,952	8,662
Other	900	-
	$ 19,958	$ 20,711

12. Fair Value Measurements

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

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

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

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.

- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

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

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and long-term debt. As of December 31, 2010, the carrying values of all of these financial instruments, except the portion of long-term debt with fixed interest rates, approximated fair value. The fair value of our fixed-rate, long-term debt is estimated based on the published market prices for the same or similar issues and is provided for the periods presented as follows:

	As of December 31,	
	2010	2009
10.375% Senior Unsecured Notes	$ 335,712	$ 327,000
4.5% Convertible Notes	225,975	218,742
	$ 561,687	$ 545,742

Recurring Fair Value Measurements

Certain assets and liabilities are measured at fair value on a recurring basis in our Consolidated Balance Sheets. The following tables summarize the valuation of these assets and liabilities for the periods presented:

	As of December 31, 2010			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Publicly traded equity securities	$ 6,440	$ 6,440	$ -	$ -
Interest rate swap assets - current	1,743	-	1,743	-
Interest rate swap assets - noncurrent	847	-	847	-
Commodity derivative assets - current	15,075	-	15,075	-
Commodity derivative assets - noncurrent	3,042	-	3,042	-
Liabilities:				
Deferred compensation - noncurrent liability	(6,948)	(6,948)	-	-
Commodity derivative liabilities - current	(388)	-	(388)	-
Totals	$ 19,811	$ (508)	$ 20,319	$ -

	As of December 31, 2009			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Publicly traded equity securities	$ 5,904	$ 5,904	$ -	$ -
Interest rate swap assets - current	1,463	-	1,463	-
Commodity derivative assets - current	14,778	-	14,778	-
Commodity derivative assets - noncurrent	2,346	-	2,346	-
Liabilities:				
Deferred compensation - noncurrent liability	(6,564)	(6,564)	-	-
Interest rate swap liabilities - current	(2,413)	-	(2,413)	-
Interest rate swap liabilities - noncurrent	(2,334)	-	(2,334)	-
Commodity derivative liabilities - current	(2,483)	-	(2,483)	-
Commodity derivative liabilities - noncurrent	(126)	-	(126)	-
Totals	$ 10,571	$ (660)	$ 11,231	$ -

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

- Publicly traded equity securities: Our publicly traded equity securities consist of various publicly traded equities that are held as assets for funding certain deferred compensation obligations. The fair values are based on quoted market prices, which are level 1 inputs.

- Commodity derivatives: We determine the fair values of our oil and gas derivative agreements based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.

- Interest rate swaps: We use an income approach using valuation techniques that connect future cash flows to a single discounted value. We estimate the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these is a level 2 input.

- Deferred compensation: Certain of our deferred compensation obligations are ultimately to be settled in cash based on the underlying fair value of certain publicly traded equity securities. The fair values of these obligations are based on quoted market prices, which are level 1 inputs.

In addition to the items provided above, there are other assets and liabilities recorded at fair value on a non-recurring basis. The most significant of these include the fair value of proved properties and tubular inventory and well materials for purposes of impairment testing, the fair value of properties held for sale and the initial determination of AROs. The factors used to determine fair value for purposes of impairment testing include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. The fair value of properties held for sale is derived using a market approach based on agreements of sale, adjusted for working capital and closing costs. Because these significant fair value inputs are typically not observable, we have categorized the amounts as level 3 inputs.

The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial fair value estimates as a level 3 input.

13. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2010, by category, for the next five years and thereafter:

Year	Minimum Rental Commitments	Drilling Commitments	Firm Transportation Commitments
2011	$ 2,666	$ 29,359	$ 7,686
2012	2,163	18,326	10,787
2013	1,980	58	8,655
2014	1,444	-	5,044
2015	1,438	-	4,042
Thereafter	3,122	-	21,170
Total	$ 12,813	$ 47,743	$ 57,384

Rental Commitments

Operating lease rental expense in the years ended December 31, 2010, 2009 and 2008 was $14.8 million, $18.0 million and $18.5 million, respectively, related primarily to field equipment, office equipment and office leases. Our rental commitments relate primarily to vehicles, office equipment and office leases.

Drilling Commitments

We have agreements to purchase oil and gas well drilling services from third parties with terms that range up to three years. The agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their original terms. The amount of penalty is based on the number of days remaining in the contractual term and declines as time passes. As of December 31, 2010, the penalty amount would have been $30.6 million if we had terminated our agreements on that date. Our management intends to utilize drilling services under these agreements for the full terms and has no plans to terminate the agreements.

Firm Transportation Commitments

We have entered into contracts that provide firm transportation capacity rights for specified volumes per day on various pipeline systems with terms that range 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.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. During 2010, we established a $0.9 million reserve for a litigation matter and a $0.5 million reserve for a sales tax audit contingency.

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. As of December 31, 2010, we have recorded asset retirement obligations of $7.4 million attributable to these activities. The regulatory burden on the oil and natural gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws have the potential to adversely affect our operations.

14. Shareholders' Equity

Common Stock

In May 2010, the shareholders of the Company approved an increase in the authorized number of shares of common stock from 64 million to 128 million shares.

In May 2009, we issued 3,500,000 shares of our common stock in a registered public offering that provided $64.8 million of net proceeds. The net proceeds were used, in addition to the proceeds from the issuance of the Senior Notes, to repay borrowings under our previous revolving credit facility.

Comprehensive Income and Accumulated Other Comprehensive Income

Comprehensive income represents changes in shareholders' equity during the reporting period including net income (loss) and other comprehensive income. Other comprehensive income includes items of income (loss) recorded directly to shareholders' equity. The following sets forth the components of comprehensive income (loss) for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Net income (loss)	$ 19,667	$ (77,368)	$ 181,520
Other comprehensive income (loss):			
Unrealized gains (losses), net of tax [1]	-	115	(4,368)
Hedging reclassification adjustments, net of tax [2]	582	3,689	5,332
Total change in hedging derivative financial instruments	582	3,804	964
Change in pension and postretirement obligations, net of tax [3]	348	140	346
	930	3,944	1,310
Comprehensive income (loss)	20,597	(73,424)	182,830
Less amounts attributable to noncontrolling interests:			
Net income (loss)	(28,090)	(37,275)	(60,436)
Other comprehensive income	(582)	(1,048)	(2,298)
Comprehensive income (loss) attributable to Penn Virginia	$ (8,075)	$ (111,747)	$ 120,096

[1] Net of tax of ($62) and ($2,352) for the years ended December 31, 2009 and 2008, respectively.
[2] Net of tax of $1,986 and $2,871 for the years ended December 31, 2009 and 2008, respectively.
[3] Net of tax of $188, $75 and $186 for the years ended December 31, 2010, 2009 and 2008, respectively.

The following table sets forth the components comprising Accumulated other comprehensive income, net of tax, for the periods presented:

	As of December 31,		
	2010	2009	2008
Pension and postretirement obligations	$ (938)	$ (1,286)	$ (1,426)
Hedging derivative financial instruments	-	-	(2,756)
	$ (938)	$ (1,286)	$ (4,182)

Treasury Stock

We maintain nonqualified deferred compensation supplemental retirement savings plans for certain employees and directors. Participants in the plans may defer and contribute a portion of their compensation to a Rabbi Trust. We include the assets and liabilities of the supplemental retirement savings plan on our Consolidated Balance Sheet. Shares of the Company's common stock purchased under the non-qualified deferred compensation plans are held in the Rabbi Trust and are presented as treasury stock carried at cost. A total of 125,357 and 113,858 shares have been recorded as treasury stock as of December 31, 2010 and 2009, respectively.

Noncontrolling Interests

In connection with the sale of our remaining PVG Common Units (Note 3), we deconsolidated PVG from our Consolidated Financial Statements resulting in the elimination of PVG's assets and liabilities as well as the related noncontrolling interests from our Consolidated Balance Sheets and Consolidated Statements of Shareholders' Equity and Comprehensive Income.

Prior to the final sale of our PVG Common Units, we reduced our limited partner interest in PVG during 2010 and 2009 while still maintaining control. In April 2010, we completed the sale of 11.25 million units of PVG owned by us for proceeds of $199.1 million, net of offering costs reducing our limited partner interest in PVG from 51.4% to 22.6%. The transaction resulted in a $70.2 million increase in noncontrolling interests and an $82.9 million increase to additional paid-in capital, net of income tax effects. In September 2009, we sold 10 million units of PVG for proceeds of $118.1 million, net of offering costs reducing our limited partner interest in PVG from 77.0% to 51.4%. The transaction resulted in a $67.7 million increase in noncontrolling interests and a $32.7 million increase to additional paid-in capital, net of income tax effects.

15. Share-Based Compensation

We have several stock compensation plans (collectively, the "Stock Compensation Plans") that allow incentive and nonqualified stock options, restricted stock and restricted stock units to be granted to key employees and officers and nonqualified stock options and deferred common stock units to be granted to directors. As of December 31, 2010, there were approximately 1,568,351 and 311,710 shares available for issuance to employees and directors, respectively, pursuant to the Stock Compensation Plans. The following table summarizes the share-based compensation expense recognized for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Stock option plans	$ 5,828	$ 6,602	$ 4,072
Common, deferred, restricted and restricted unit plans	1,983	2,525	1,887
	$ 7,811	$ 9,127	$ 5,959

Stock Options

The exercise price of all options granted under the Stock Compensation Plans is equal to the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors (the "Committee"). Generally, options vest over a three-year period, with one-third vesting in each year. In addition, all options will vest upon a change of control of the Company, as defined in the Stock Compensation Plans. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be automatically forfeited, (ii) by reason of death, disability or retirement (age 62 and providing ten consecutive years of service) the grantee's options will automatically vest and (iii) for any other reason, the grantee's unvested options will be automatically forfeited. In the case of directors, if a grantee's membership on our board of directors terminates for any reason, the grantee's unvested options will be automatically forfeited. We have consistently issued new shares to satisfy share option exercises.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	2010	2009	2008
Expected volatility	59.5% to 67.6%	51.7% to 64.9%	38.5% to 56.1%
Dividend yield	0.90% to 1.20%	1.25% to 1.49%	0.37% to 0.67%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.68% to 2.30%	1.23% to 1.84%	1.86% to 2.87%

The following table summarizes activity for our most recent fiscal year with respect to awarded options:

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	2,276,917	$ 24.86		
Granted	609,177	23.89		
Exercised	(136,113)	11.95		
Forfeited	(605,624)	27.35		
Outstanding at end of year	2,144,357	$ 24.70	7.5	$ 5,178
Exercisable at end of year	1,177,462	$ 27.29	6.6	$ 2,687

The weighted-average grant-date fair value of options granted during the years ended December 31, 2010, 2009 and 2008 was $10.13, $5.60 and $13.20 per option. The total intrinsic value of options exercised during the years ended December 31, 2010 and 2008 was $1.2 million and $13.1 million. There were no options exercised during 2009.

As of December 31, 2010, we had $6.1 million of unrecognized compensation cost related to unvested stock options. We expect that cost to be recognized over a weighted-average period of 0.8 years. The total grant-date fair values of stock options that vested in 2010, 2009 and 2008 were $4.6 million, $5.7 million and $2.7 million, respectively.

Restricted Stock

Restricted stock vests upon terms established by the Committee and as specified in the award agreement. In addition, all restricted stock will vest upon a change of control of the Company. If a grantee's employment terminates for any reason other than death or disability, the grantee's restricted stock will be automatically forfeited unless otherwise determined by the Committee and specified in the award agreement. If a grantee's employment terminates by reason of death or disability, or if a grantee becomes retirement eligible (age 62 and providing 10 consecutive years of service), the grantee's restricted stock will automatically vest. Except as specified by the Committee, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock vests generally over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

The following table summarizes the status of our nonvested restricted stock as of December 31, 2010 and changes during the year then ended:

	Nonvested Restricted Stock	Weighted-Average Grant Date Fair Value
Balance at beginning of year	20,660	$ 40.82
Vested	(12,432)	39.88
Forfeited	(2,271)	42.27
Balance at end of year	5,957	$ 42.27

As of December 31, 2010, there was less than $0.1 million of unrecognized compensation cost attributable to nonvested restricted stock. We expect that cost to be recognized during 2011. The total grant-date fair values of restricted stock that vested in 2010, 2009 and 2008 were $0.5 million, $1.3 million and $1.0 million, respectively.

Deferred Common Stock Units

A portion of the compensation paid to non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, 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 our common stock.

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

	Deferred Common Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	83,186	$ 29.13
Granted	28,452	19.76
Converted	(8,382)	28.86
Balance at end of year	103,256	$ 26.76

As of December 31, 2010, 2009 and 2008, shareholders' equity included deferred compensation obligations of $2.7 million, $2.4 million and $2.2 million, respectively, and corresponding amounts for treasury stock.

Restricted Stock Units

A restricted stock unit entitles the grantee to receive a share of common stock upon the vesting of the restricted stock unit or, at the discretion of the Committee, the cash equivalent of the value of a share of common stock. The Committee determines the time period over which restricted stock units granted to employees and directors will vest. In addition, all restricted stock units will vest upon a change of control of the Company. If a director's membership on the board of directors terminates for any reason, or an employee's employment with us and our affiliates terminates for any reason other than retirement after reaching age 62 and completing 10 years of consecutive service, the grantee's restricted stock units will be automatically forfeited unless, and to the extent, the Committee provides otherwise. Restricted stock units generally vest over a three-year period, with one-third vesting in each year. The Committee, in its discretion, may grant tandem dividend equivalent rights with respect to restricted stock units. A dividend equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash dividends made with respect to a share of common stock during the period such restricted stock unit is outstanding. Payments of dividend equivalent rights associated with restricted stock units that are expected to vest are recorded as dividends; payments associated with restricted stock units that are not expected to vest are recorded as compensation expense.

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

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year [1]	71,914	$ 15.62
Granted	64,171	23.86
Vested [2]	(45,476)	19.76
Forfeited	(18,394)	20.25
Balance at end of year [1]	72,215	$ 18.77

[1] Excludes 39,841 and 61,344 units at the beginning and end of year, respectively, that have vested due to retirement eligibility, but have not yet been settled or converted to common shares.
[2] Includes 21,503 units that vested upon the grant date in 2010 due to retirement eligibility.

As of December 31, 2010, we had $1.0 million of unrecognized compensation cost attributable to nonvested restricted stock units. We expect that cost to be recognized over a weighted-average period of 1.0 years. The total grant-date fair values of restricted stock units that vested in 2010 and 2009 were $0.9 million and $0.6 million, respectively.

16. Restructuring Activities

In November 2009, we implemented an organization restructuring that resulted in the transfer of certain corporate administrative and oil and gas accounting functions from our Kingsport, Tennessee office location to our Houston, Texas and Radnor, Pennsylvania locations. In addition, the restructuring resulted in the relocation of our eastern region oil and gas divisional office from Kingsport to Pittsburgh, Pennsylvania. During 2010, we expanded the program to restructure key operational and management positions to complete our transformation to a pure play exploration and production company. Approximately 30 employees were terminated in connection with the restructuring. We incurred special termination benefit costs of approximately $2.6 million, including $0.5 million in 2009 and $2.1 million in 2010, that were paid to eligible employees upon the completion of various transition activities. These costs were charged to operations ratably over the transition period which concluded during the second quarter of 2010. We also incurred relocation costs and other incremental costs associated with staffing and expanding our other office locations, including the new office in Pittsburgh.

In connection with these restructuring activities, we also ceased operations at our Kingsport, Tennessee office location during the second quarter of 2010 and assigned the underlying lease of the facility to PVR. In connection with this assignment, we incurred a one-time lease assignment charge, which was paid in July 2010.

These restructuring charges, including those described above, are included in the General and administrative expenses caption on our Consolidated Statements of Income and are comprised of the following for the periods presented:

	For the Year Ended December 31,	
	2010	2009
Termination benefits	$ 2,081	$ 529
Employee and office relocation costs	1,597	-
Other incremental costs	1,022	-
Lease assignment charge	3,500	-
	$ 8,200	$ 529

The following table summarizes the termination benefit obligations as of and for the years ended December 31:

	2010	2009
Balance at beginning of period	$ 529	$ -
Termination benefits accrued	2,081	529
Cash payments	(2,546)	-
Balance at end of period	$ 64	$ 529

17. Impairments

During 2010, we incurred impairment charges related to our coal bed methane properties as a result of market declines in gas prices and to an area in the Anadarko basin of the Mid-Continent region where we drilled an uneconomic well. In addition, we recorded impairment charges attributable to certain oil and gas inventory assets triggered primarily by declines in asset quality. We also incurred impairment charges on properties in North Dakota that were held for sale at the end of 2009. These properties were ultimately sold during 2010. During 2009, we incurred impairment charges in connection with the initial classification of the Gulf Coast properties as assets held for sale at their fair value less costs to sell, as well as impairments attributable to tubular inventory and other oil and gas properties. The impairment charges in 2008 relate to declines in spot and future oil and gas prices and declines in well performance which reduced reserves on certain properties in the Mid-Continent and Appalachian regions.

The following table summarizes impairment charges recorded during the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Oil and gas properties - held for sale	$ 1,124	$ 97,400	$ -
Oil and gas properties	43,067	4,932	19,963
Other - tubular inventory and well materials	1,768	4,083	-
	$ 45,959	$ 106,415	$ 19,963

18. Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Interest on borrowings and related fees	$ 43,060	$ 33,374	$ 19,068
Accretion on original issue discount	8,109	7,523	6,241
Amortization of debt issuance costs	3,875	2,679	1,715
Interest rate swaps	-	3,969	1,015
Capitalized interest	(1,384)	(2,318)	(2,987)
Other, net	19	(996)	(425)
	$ 53,679	$ 44,231	$ 24,627

19. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2010	2009	2008
Net income (loss) from continuing operations	$ (65,327)	$ (130,856)	$ 93,619
Income from discontinued operations, net of tax [1]	33,448	53,488	87,901
Gain on sale of discontinued operations, net of tax	51,546	-	-
Less net income attributable to noncontrolling interests	(28,090)	(37,275)	(60,436)
Net income (loss) attributable to common shareholders	$ (8,423)	$ (114,643)	$ 121,084
Less: Portion of subsidiary net income allocated to undistributed share-based compensation awards, net of tax	(28)	(116)	(295)
	$ (8,451)	$ (114,759)	$ 120,789
Weighted-average shares, basic	45,553	43,811	41,760
Effect of dilutive securities [2]	-	-	271
Weighted-average shares, diluted	45,553	43,811	42,031

[1] For purposes of determining earnings per share, net income attributable to noncontrolling interests is applied against income from discontinued operations as they are completely attributable to PVG's operations.

[2] For 2010 and 2009, approximately 0.2 and 0.1 million potentially dilutive securities, including the Convertible Notes, stock options, restricted stock and phantom stock had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

Supplemental Quarterly Financial Information (Unaudited)

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
2010								
Revenues	$	67,878	$	53,288	$	68,953	$	64,319
Operating income (loss) [1]	$	92	$	(20,878)	$	(53,053)	$	(24,969)
Net loss from continuing operations	$	10,766	$	(21,097)	$	(30,159)	$	(24,837)
Income (loss) from discontinued operations, net of tax	$	12,174	$	21,308	$	-	$	(34)
Gain on sale of discontinued operations, net of tax	$	-	$	49,612	$	-	$	1,934
Income (loss) attributable to Penn Virginia Corp.	$	13,594	$	31,079	$	(30,159)	$	(22,937)
Earnings (loss) per share - Basic [2]:								
Continuing operations	$	0.24	$	(0.46)	$	(0.66)	$	(0.54)
Discontinued operations	$	0.06	$	0.06	$	-	$	-
Gain on sale of discontinued operations	$	-	$	1.08	$	-	$	0.04
Net income (loss)	$	0.30	$	0.68	$	(0.66)	$	(0.50)
Earnings (loss) per share - Diluted [2]:								
Continuing operations	$	0.24	$	(0.46)	$	(0.66)	$	(0.54)
Discontinued operations	$	0.06	$	0.06	$	-	$	-
Gain on sale of discontinued operations	$	-	$	1.08	$	-	$	0.04
Net income (loss)	$	0.30	$	0.68	$	(0.66)	$	(0.54)
Weighted-average shares outstanding:								
Basic		45,465		45,539		45,591		45,615
Diluted		45,761		45,790		45,591		45,615
2009								
Revenues	$	64,574	$	55,903	$	55,719	$	59,010
Operating loss [3]	$	(29,134)	$	(37,648)	$	(122,069)	$	(16,495)
Net loss from continuing operations	$	(10,632)	$	(26,217)	$	(84,712)	$	(9,295)
Income from discontinued operations, net of tax	$	7,081	$	10,379	$	15,321	$	20,707
Loss attributable to Penn Virginia Corp.	$	(7,209)	$	(22,183)	$	(79,900)	$	(5,351)
Earnings (loss) per share - Basic [2]:								
Continuing operations	$	(0.25)	$	(0.61)	$	(1.87)	$	(0.21)
Discontinued operations	$	0.08	$	0.09	$	0.11	$	0.09
Net income (loss)	$	(0.17)	$	(0.52)	$	(1.76)	$	(0.12)
Earnings (loss) per share - Diluted [2]:								
Continuing operations	$	(0.25)	$	(0.61)	$	(1.87)	$	(0.21)
Discontinued operations	$	0.08	$	0.09	$	0.11	$	0.09
Net income (loss)	$	(0.17)	$	(0.52)	$	(1.76)	$	(0.12)
Weighted-average shares outstanding:								
Basic		41,922		42,798		45,427		45,434
Diluted		41,922		42,798		45,427		45,434

[1] Includes an impairment $1.1 million for oil and gas properties held for sale during the quarter ended June 30, 2010. Includes impairments of oil and gas assets of $35.1 million and $9.7 million for the quarters ended September 30, 2010 and December 31, 2010, respectively.

[2] The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.

[3] Includes impairments of oil and gas assets of $1.2 million, $3.3 million, $4.4 million and $0.1 million during the first through fourth quarters of 2009, respectively. Includes impairments of $87.9 million and $9.5 million for oil and gas properties held for sale during the third and fourth quarters of 2009, respectively.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following supplemental information regarding the oil and gas producing activities is presented in accordance with the requirements of the current oil and gas accounting standards.

Capitalized Costs Relating to Oil and Gas Producing Activities

	As of December 31,		
	2010	2009	2008
Proved properties	$ 293,486	$ 353,386	$ 322,030
Unproved properties	171,303	73,067	155,803
Wells, equipment and facilities	1,840,154	1,527,749	1,623,274
Support equipment	6,255	5,938	6,021
	2,311,198	1,960,140	2,107,128
Accumulated depreciation and depletion	(609,380)	(487,106)	(469,296)
Net capitalized costs	$ 1,701,818	$ 1,473,034	$ 1,637,832

During the years ended December 31, 2010, 2009 and 2008, an additional $0.1 million, $0.4 million and $0.5 million, respectively, related to ARO assets were added to the cost basis of oil and gas wells for wells drilled.

Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2010	2009	2008
Proved property acquisition costs	$ 5,671	$ -	$ -
Unproved property acquisition costs	133,185	14,996	93,110
Exploration costs	66,886	7,179	30,373
Development costs and other	244,092	149,625	518,213
Total costs incurred	$ 449,834	$ 171,800	$ 641,696

Results of Operations for Oil and Gas Producing Activities

The following table includes results solely from the production and sale of oil and gas and a non-cash charge for property impairments. It excludes corporate-related general and administrative expenses and gains or losses on property dispositions. The income tax expense is calculated by applying the statutory tax rates to the revenues after deducting costs, which include depletion allowances and giving effect to oil and gas related permanent differences and tax credits.

	Year Ended December 31,		
	2010	2009	2008
Revenues	$ 251,336	$ 228,659	$ 436,622
Production expenses	63,854	72,255	82,191
Exploration expenses	49,641	57,754	42,436
Depreciation and depletion expense	130,816	150,429	132,276
Impairment of oil and gas properties	45,959	106,415	19,963
	(38,934)	(158,194)	159,756
Income tax expense (benefit)	(15,184)	(61,221)	61,985
Results of operations	$ (23,750)	$ (96,973)	$ 97,771

The combined depletion and accretion expense related to asset retirements that were recognized during 2010, 2009 and 2008 in DD&A expense was approximately $0.7 million, $0.7 million and $0.4 million.

Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes our royalty and net working interest share of the reserves in oil and gas properties. All reserves are located in the United States. Net proved oil and gas reserves for the three years ended December 31, 2010 were estimated by Wright & Company, Inc., utilizing data compiled by us.

There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years.

Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves are proved reserves expected to be recovered through new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion. The proved undeveloped reserves included in our current estimates relate to wells that are forecasted to be drilled within the next five years.

Our Manager of Engineering is primarily responsible for overseeing the preparation of the Company's reserve estimate by our independent third party engineers, Wright & Company, Inc. The Manager of Engineering has over 24 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the state of Texas as a Professional Engineer. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

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

Proved Developed and Undeveloped Reserves	Natural Gas (MMcf)	Oil and Condensate (MBbl)	Total Equivalents (MMcfe)
December 31, 2007	588,263	15,220	679,582
Revisions of previous estimates	(59,828)	(131)	(60,614)
Extensions, discoveries and other additions [1]	267,190	12,783	343,888
Production	(41,493)	(898)	(46,881)
Purchase of reserves	-	-	-
Sale of reserves in place	-	-	-
December 31. 2008	754,132	26,974	915,975
Revisions of previous estimates [2]	(110,349)	(8,442)	(160,995)
Extensions, discoveries and other additions [3]	180,448	9,203	235,666
Production	(43,337)	(1,277)	(51,000)
Purchase of reserves	-	-	-
Sale of reserves in place	(4,229)	(71)	(4,659)
December 31, 2009	776,665	26,387	934,987
Revisions of previous estimates [4]	(71,421)	5,202	(40,210)
Extensions, discoveries and other additions [5]	90,439	4,069	114,851
Production	(38,919)	(1,380)	(47,201)
Purchase of reserves	3,288	9	3,342
Sale of reserves in place	(15,070)	(1,490)	(24,014)
December 31, 2010	744,982	32,797	941,755
Proved Developed Reserves:			
December 31, 2008	411,366	9,895	470,736
December 31, 2009	388,382	8,357	438,524
December 31, 2010	412,644	14,813	501,521

[1] Increased due to the drilling of 158 wells on locations which were not classified as proved undeveloped locations in our 2007 year-end reserve report and the addition of 1,031 new proved undeveloped locations as a result of our 2008 drilling activities.

[2] We had downward revisions of 161 Bcfe which were primarily the result of the following: 1) downward revisions of 63.1 Bcfe due to price, 2) a downward revision of 27.1 Bcfe in Appalachia for the removal of proved undeveloped reserves, which resulted from wells that no longer met the reasonable certainty threshold, 3) downward revisions of 20.1 Bcfe for NGLs that we received in East Texas as a result of lower plant yields and 4) various downward revisions amounting to 50.7 Bcfe across our assets which were the result of well performance and the application of the revised oil and gas reserve calculation methodology required by the SEC in 2009.

[3] We added 235.7 Bcfe due to the drilling of 13 wells on locations which were not classified as proved undeveloped locations in our 2008 year-end reserve report and the addition of 105 new proved undeveloped locations, primarily in the Gulf Coast and Mid-Continent regions, as a result of our 2009 drilling activities.

[4] We had downward revisions of 40.5 Bcfe which were primarily the result of the following: 1) downward revisions of 45 Bcfe due to the removal of 200 proved undeveloped locations which would not be developed within five years in accordance with SEC requirements, 2) upward revisions of 34 Bcfe as a result of processing the gas in the Mid-Continent Granite Wash for NGLs, 3) upward revisions of 12 Bcfe due to higher prices and 4) various downward revisions for 39 Bcfe across our assets which were the result of well performance, lease expirations and interest changes.

[5] Increased due to the drilling of 16 wells on locations which were not classified as proved undeveloped locations in our 2009 year-end reserve report and the addition of 51 new proved undeveloped locations, primarily in east Texas as a result of our 2010 drilling activities.

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves. For 2010 and 2009, future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end to the estimated future production of proved reserves. For 2008, future cash inflows were computed by applying year-end prices of oil and gas and estimated costs as of that fiscal year-end to the estimated future production of proved reserves. Natural gas prices were escalated only where existing contracts contained fixed and determinable escalation clauses. Contractually provided natural gas prices in excess of estimated market clearing prices were used in computing the future cash inflows only if we expect to continue to receive higher prices under legally enforceable contract terms. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year Ended December 31,		
	2010	2009	2008
Future cash inflows	$ 4,833,030	$ 4,178,449	$ 5,031,678
Future production costs	(1,388,857)	(1,300,235)	(1,588,959)
Future development costs	(879,193)	(888,493)	(924,219)
Future net cash flows before income tax	2,564,980	1,989,721	2,518,500
Future income tax expense	(687,928)	(491,832)	(567,779)
Future net cash flows	1,877,052	1,497,889	1,950,721
10% annual discount for estimated timing of cash flows	(1,235,633)	(973,118)	(1,221,320)
Standardized measure of discounted future net cash flows	$ 641,419	$ 524,771	$ 729,401

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2010	2009	2008
Sales of oil and gas, net of production costs	$ (180,568)	$ (157,891)	$ (355,552)
Net changes in prices and production costs	180,316	(314,209)	(318,730)
Extensions, discoveries and other additions	59,729	138,482	233,603
Development costs incurred during the period	153,563	65,043	112,925
Revisions of previous quantity estimates	(50,471)	(158,844)	(93,346)
Purchases of reserves-in-place	2,239	-	-
Sale of reserves-in-place	(47,740)	-	-
Accretion of discount	68,817	90,796	126,114
Net change in income taxes	(73,332)	15,168	110,670
Other changes	4,095	116,825	(58,193)
Net increase (decrease)	116,648	(204,630)	(242,509)
Beginning of year	524,771	729,401	971,910
End of year	$ 641,419	$ 524,771	$ 729,401

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected above do not necessarily represent the economic reality of such transactions. See “Costs Incurred in Certain Oil and Gas Activities” earlier in this Note and our Consolidated Statements of Cash Flows.

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

None.

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

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2010. 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, 2010, 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, 2010. 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, 2010, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has issued an attestation report on the internal control over financial reporting as of December 31, 2010, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B ***Other Information***

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2010 which we did not disclose.

Part III

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11 ***Executive Compensation***

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15 ***Exhibits, Financial Statement Schedules***

The following documents are filed as exhibits to this Annual Report on Form 10-K:

(1) Financial Statements—The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 44 of this Annual Report on Form 10-K.

(2.1) Purchase and Sale Agreement dated December 23, 2009 between Penn Virginia Oil & Gas, L.P. and Hilcorp Energy I, L.P., as amended by Amendment and Supplement to Purchase and Sale Agreement dated January 29, 2010 (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on February 3, 2010).

(2.2) Purchase and Sale Agreement dated December 23, 2009 between Penn Virginia Oil & Gas Corporation and Hilcorp Energy I, L.P. (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on February 3, 2010).

(3.1) Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.1.1) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant's Annual Report on Form 10-K for the year ended December 31, 1999).

(3.1.2) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3 to Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004).

(3.1.3) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on June 12, 2007).

(3.1.4) Articles of Amendment of Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on May 10, 2010).

(3.2) Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on October 29, 2010).

(4.1) Subordinated Indenture dated December 5, 2007 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.1.1) First Supplemental Indenture relating to the 4.50% Convertible Senior Subordinated Notes due 2012, dated December 5, 2007 between Penn Virginia Corporation, as Issuer, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.1.2) Form of Note for 4.50% Convertible Senior Subordinated Notes due 2012 (incorporated by reference to Exhibit A to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(4.2) Senior Indenture dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2009).

(4.2.1) First Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).

(4.2.2) Form of Note for 10.375% Senior Notes due 2016 (incorporated by reference to Annex A to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).

(10.1) Credit Agreement dated November 18, 2009 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 20, 2009).

(10.2) Call Option Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.3) Call Option Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.4) Call Option Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.5) Call Option Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.7 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.6) Warrant Confirmation dated November 29, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.7) Warrant Transaction Amendment dated December 3, 2007 between JPMorgan Chase Bank, National Association, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.9 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.8) Warrant Confirmation dated November 29, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.9) Warrant Transaction Amendment dated December 3, 2007 between Wachovia Bank, National Association and Penn Virginia Corporation (incorporated by reference to Exhibit 10.11 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.10) Warrant Confirmation dated November 29, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.11) Warrant Transaction Amendment dated December 3, 2007 between Lehman Brothers OTC Derivatives Inc. and Penn Virginia Corporation (incorporated by reference to Exhibit 10.10 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.12) Warrant Confirmation dated November 29, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.8 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.13) Warrant Transaction Amendment dated December 3, 2007 between UBS AG, London Branch and Penn Virginia Corporation (incorporated by reference to Exhibit 10.12 to Registrant's Current Report on Form 8-K filed on December 5, 2007).

(10.14) Contribution Agreement dated June 7, 2010 by and among Penn Virginia Resource GP Corp., Penn Virginia GP Holdings, L.P. and PVG GP, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 7, 2010).

(10.15) Penn Virginia Corporation and Affiliated Companies' Employees' 401(k) Plan (incorporated by reference to Exhibit 10.5 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*

(10.16) Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.17) Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*

(10.18) Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.29 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007). *

(10.19) Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.30 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*

(10.20) Penn Virginia Corporation Seventh 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 August 2, 2010).*

(10.20.1)	Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.20.2)	Form of Agreement for Restricted Stock Awards under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.33 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.20.3)	Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation Seventh Amended and Restated 1999 Employee Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on February 23, 2009).*
(10.21)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and A. James Dearlove (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.22)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.23)	Executive Change of Control Severance Agreement dated October 17, 2008 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 22, 2008).*
(10.24)	Executive Change of Control Severance Agreement dated December 8, 2010 between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 10, 2010).*
(10.25)	Amended and Restated Change of Location Severance Agreement dated March 30, 2010 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on March 31, 2010).*
(10.26)	Resignation Agreement and Release dated November 2, 2010 between Penn Virginia Corporation and Frank A. Pici (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on November 3, 2010).*
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges Calculation.
(14.1)	Penn Virginia Corporation Code of Business Conduct and Ethics (incorporated by reference to Exhibit 14.1 to Registrant's Current Report on Form 8-K filed on July 27, 2009).
(21.1)	Subsidiaries of Penn Virginia Corporation.
(23.1)	Consent of KPMG LLP.
(23.2)	Consent of Wright & Company, Inc.
(31.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1)	Report of Wright & Company, Inc. dated January 17, 2011 concerning evaluation of oil and gas reserves.
(101.INS)	XBRL Instance Document
(101.SCH)	XBRL Taxonomy Extension Schema Document
(101.CAL)	XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF)	XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB)	XBRL Taxonomy Extension Label Linkbase Document
(101.PRE)	XBRL Taxonomy Extension Presentation Linkbase Document

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* 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

February 25, 2011	By:	/s/ Steven A. Hartman **Steven A. Hartman** **Senior Vice President and Chief Financial Officer**
February 25, 2011	By:	/s/ JOAN C. SONNEN **Joan C. Sonnen** **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	February 25, 2011
/s/ JOHN U. CLARKE **John U. Clarke**	Director	February 25, 2011
/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Director	February 25, 2011
/s/ A. JAMES DEARLOVE **A. James Dearlove**	Director and Chief Executive Officer	February 25, 2011
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	February 25, 2011
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 25, 2011
/s/ PHILIPPE VAN MARCKE DE LUMMEN **Philippe van Marcke de Lummen**	Director	February 25, 2011
/s/ H. Baird Whitehead **H. Baird Whitehead**	Director and President	February 25, 2011
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	February 25, 2011

Exhibit 12.1

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges Calculation
(in thousands, except ratios)

	Year Ended December 31,				
	2006	**2007**	**2008**	**2009**	**2010**
Earnings					
Pre-tax income *	$ 91,397	$ 52,655	$ 146,238	$ (219,068)	$ (109,562)
Fixed charges	11,525	28,162	33,772	53,535	60,003
Total Earnings	$ 102,922	$ 80,817	$ 180,010	$ (165,533)	$ (49,559)
Fixed Charges					
Interest expense	$ 8,828	$ 23,717	$ 27,614	$ 47,545	$ 55,063
Rental Interest Factor	2,697	4,445	6,158	5,990	4,940
Total Fixed Charges	$ 11,525	$ 28,162	$ 33,772	$ 53,535	$ 60,003
Ratio of Earnings to Fixed Charges	**8.9x**	**2.9x**	**5.3x**	**	**

* Includes cash distributions from equity affiliates and excludes equity earnings from affiliates. Also excludes capitalized interest.

** During 2009 and 2010, earnings were deficient by $165,533 and $49,559, respectively, regarding the coverage of fixed charges

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C.	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware
Penn Virginia Resource GP Corp.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statement on Form S-8 (No. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, and 333-159304) of Penn Virginia Corporation (the "Company") of our reports dated March 1, 2010, with respect to the consolidated balance sheets of the Company as of December 31, 2010 and 2009, 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, 2010, and the effectiveness of internal control over financial reporting as of December 31, 2010, which reports appear in the December 31, 2010 annual report on Form 10-K of the Company.

/s/ KPMG LLP

Houston, Texas
February 25, 2011

Exhibit 23.2

CONSENT OF WRIGHT & COMPANY, INC.

As independent oil and gas consultants, Wright & Company, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-59647, 333-96463, 333-82274, 333-96465, 333-103455, 333-143514, 333-82304 and 333-159304) of Penn Virginia Corporation of information from our reserves report dated January 17, 2011 titled "Evaluation of Oil and Gas Reserves, To the Interests of Penn Virginia Oil & Gas Corporation, In Certain Properties Located in Various States, Pursuant to the Requirements of the Securities and Exchange Commission, Effective January 1, 2011, Jobs 10.1211, 10.1212 and 10.1213" and all references to our firm included in or made a part of the Penn Virginia Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about February 25, 2011.

WRIGHT & COMPANY, INC.
TX Firm Registration No. F-12302

By: /s/ D. RANDALL WRIGHT
D. Randall Wright
President

Brentwood, Tennessee
February 1, 2011

Exhibit 31.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, A. James Dearlove, Chief Executive Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: February 25, 2011

/s/ A. JAMES DEARLOVE

A. James Dearlove
Chief Executive Officer

Exhibit 31.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: February 25, 2011

/S/ Steven A. Hartman

Steven A. Hartman
Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the “Company”) on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, A. James Dearlove, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2011

/s/ A. JAMES DEARLOVE
A. James Dearlove
Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2011

/S/ Steven A. Hartman
Steven A. Hartman
Senior Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

January 17, 2011

Penn Virginia Oil & Gas CorporationThree Radnor Corporate Center
100 Matsonford Road, Suite 300
Radnor, PA 19087

Attention: Mr. Frank E. Falbo, Jr.

SUBJECT: Evaluation of Oil and Gas Reserves
To the Interests of Penn Virginia Oil & Gas Corporation
In Certain Properties Located in Various States
Pursuant to the Requirements of the
Securities and Exchange Commission
Effective January 1, 2011
Jobs 10.1211, 10.1212 and 10.1213

At the request of Penn Virginia Oil & Gas Corporation (PVOG), Wright & Company, Inc. (Wright) has performed an evaluation to estimate proved reserves and associated cash flow and economics from certain properties to the subject interests. This evaluation was authorized by Mr. Frank E. Falbo, Jr. of PVOG. Projections of the reserves and cash flow to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered applicable at the effective date. This reserves evaluation is pursuant to the financial reporting requirements of the Securities and Exchange Commission (SEC) as specified in Regulation S-X, Rule 4-10(a) and Regulation S-K, Rule 1202(a)(8). It is the understanding of Wright that the purpose of this evaluation is for inclusion in relevant registration statements or other filings to the SEC. The effective date of this report is January 1, 2011. The report was completed January 17, 2011. The following is a summary of the results of the evaluation.

Penn Virginia Oil & Gas Corporation SEC Parameters	**Proved Developed**		**Total Proved Developed (PDP & PDNP)**	**Proved Undeveloped (PUD)**	**Total Proved (PDP, PDNP & PUD)**
	Producing (PDP)	**Nonproducing (PDNP)**			
Net Reserves to the Evaluated Interests					
Oil, Mbbl:	3,625.496	409.780	4,035.277	4,048.318	8,083.593
Gas, MMcf:	384,067.531	28,576.191	412,643.781	332,338.500	744,982.250
NGL, Mbbl:	9,184.942	1,592.689	10,777.630	13,934.270	24,711.900
Gas Equivalent, MMcfe (1 bbl = 6 Mcfe)	460,930.159	40,591.005	501,521.223	440,234.028	941,755.208
Cash Flow (BTAX), M$ Undiscounted:	1,528,022.500	112,235.016	1,640,257.500	924,723.250	2,564,980.250
Discounted at 10% Per Annum:	750,169.688	35,999.875	786,169.438	91,977.953	878,147.250

It should be noted that some minor differences might exist between the total summaries and the table totals due to rounding techniques in the ARIES™ petroleum software program.

The properties evaluated in this report are contained in PVOG's wholly owned subsidiaries of Penn Virginia Oil & Gas Corporation (Eastern Region), Penn Virginia Oil & Gas, L.P. (Gulf Coast Region) and Penn Virginia MC Energy, LLC (Mid-Continent Region). The Eastern Region includes properties located in Kentucky, Mississippi, Pennsylvania, Virginia, and West Virginia. The Gulf Coast Region includes properties located in Louisiana and Texas. The Mid-Continent Region includes properties in Oklahoma and Texas. According to PVOG, the total proved reserves included in this evaluation represent 100 percent of the reported total proved reserves of PVOG.

Proved oil and gas reserves are those quantities of oil and gas which can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. As specified by the SEC regulations, when calculating economic producibility, the base product price must be the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the prior 12-month period. The benchmark base prices used for this evaluation were $4.376 per Million British thermal units (MMBtu) for natural gas at Henry Hub, LA and $79.43 per barrel for West Texas Intermediate oil at Cushing, OK. These benchmark prices were adjusted for energy content, quality and basis differential, as appropriate. The average adjusted product prices used to estimate proved reserves are $4.293 per Mcf of gas and $76.49 per bbl of oil. Prices for oil and gas were held constant for the life of the properties. The Natural Gas Liquids (NGL) product price was estimated to be approximately 54 percent of the base oil price, resulting in an average adjusted price of $41.14 per barrel.

Oil and other liquid hydrocarbons are expressed in thousands of United States (U.S.) barrels (Mbbl), one barrel equaling 42 U.S. gallons. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. No adjustment of the individual gas volumes to a common pressure base has been made.

Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, standard state and county taxes, operating expenses, and investments as applicable. The cash flow is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. The cash flow (BTAX) was discounted at an annual rate of 10.00 percent (PCT) in accordance with the reporting requirements of the SEC.

The estimates of reserves contained in this report were determined by accepted industry methods, and the procedures used in this evaluation are appropriate for the purpose served by the report. Where sufficient production history and other data were available, reserves for producing properties were determined by extrapolation of historical production or sales trends. Analogy to similar producing properties was used for development projects and for those properties that lacked sufficient production history to yield a definitive estimate of reserves. When appropriate, Wright may have also utilized volumetric calculations and log correlations in the determination of estimated ultimate recovery (EUR). These calculations are often based upon limited log and/or core analysis data and incomplete formation fluid and rock data. Since these limited data must frequently be extrapolated over an assumed drainage area, subsequent production performance trends or material balance calculations may cause the need for significant revisions to the estimates of reserves. Wright has used all methods and procedures as it considered necessary under the circumstances to prepare this report.

Oil and gas reserves were evaluated for the proved developed producing (PDP), proved developed nonproducing (PDNP) and proved undeveloped (PUD) reserves categories. The summary classification of total proved reserves combines the PDP, PDNP and PUD categories. In preparing this evaluation, no attempt has been made to quantify the element of uncertainty associated with any category. Reserves were assigned to each category as warranted. Wright is not aware of any local, state, or federal regulations that would preclude PVOG from continuing to produce from currently active wells or to fully develop those properties included in this report.

There are significant uncertainties inherent in estimating reserves, future rates of production and the timing and amount of future costs. Oil and gas reserves estimates must be recognized as a subjective process that cannot be measured in an exact way and estimates of others may differ materially from those of Wright. The accuracy of any reserves estimate is a function of quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates or changes in the analogous properties may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that ultimately are recovered.

All data utilized in the preparation of this report were provided by PVOG. No inspection of the properties was made as this was not considered to be within the scope of this evaluation. Wright has not independently verified the accuracy and completeness of information and data furnished by PVOG with respect to ownership interests, oil and gas production or sales, historical costs of operation and development, product prices, or agreements relating to current and future operations and sales of production. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by PVOG with regard to product pricing, appropriate adjustments, lease operating expenses, and capital investments for drilling the undeveloped locations. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, Wright did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. In accordance with the requirements of the SEC, all operating costs were held constant for the life of the properties.

No consideration was given in this report to potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this evaluation for potential liability for restoration and to clean up damages, if any, caused by past or future operating practices.

Wright is an independent petroleum consulting firm founded in 1988 and owns no interests in the oil and gas properties covered by this report. No employee, officer, or director of Wright is an employee, officer, or director of PVOG nor does Wright, or any of its employees have direct financial interest in PVOG. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report.

This report is prepared for the information of PVOG, its shareholders, and for the information and assistance of its independent public accountants in connection with their review of and report upon the financial statements of PVOG and for reporting disclosures as required by the SEC. This report is also intended for public disclosure as an exhibit in filings made to the SEC by PVOG.

Based on data and information provided by PVOG, and the specified economic parameters, operating conditions, and government regulations considered applicable at the effective date, it is Wright's conclusion that this report provides a fair and accurate representation of the oil and gas reserves to the interests of PVOG in those certain properties included in this report.

The professional qualifications of the petroleum consultants responsible for the evaluation of the reserves and economics information presented in this report meet the standards of Reserves Estimator as defined in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* as promulgated by the Society of Petroleum Engineers.

It has been a pleasure to serve you by preparing this evaluation. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.
TX Lic. # F-12302

By: /s/ D. Randall Wright
D. Randall Wright
President