WPX ENERGY, INC.
Form 10-K
February 28, 2012


# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# Form 10-K

**(Mark One)**

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2011**

**OR**

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from to**

**Commission file number 1-4174**

# WPX Energy, Inc.

**(Exact Name of Registrant as Specified in Its Charter)**

| | |
|---|---|
| **Delaware** | **45-1836028** |
| **(State or Other Jurisdiction of Incorporation or Organization)** | **(IRS Employer Identification No.)** |
| **One Williams Center, Tulsa, Oklahoma** | **74172-0172** |
| **(Address of Principal Executive Offices)** | **(Zip Code)** |

**918-573-2000**

**(Registrant s Telephone Number, Including Area Code)**

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

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| **Common Stock, $0.01 par value** | **New York Stock Exchange** |

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

**None**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ

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

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

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

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 þ (Do not check if a smaller reporting company) | Smaller reporting company ¨ |

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

As of June 30, 2011, the registrant s common stock was not publicly traded.

The number of shares outstanding of the registrant s common stock outstanding at February 24, 2012 was 198,628,120

**DOCUMENTS INCORPORATED BY REFERENCE**

Information required by Part III will be included in an amendment to this Form 10-K to be filed with the Securities and Exchange Commission within 120 days of December 31, 2011.

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**FORM 10-K**

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## CERTAIN DEFINITIONS

The following oil and gas measurements and industry and other terms are used in this Form 10-K. As used herein, production volumes represent sales volumes, unless otherwise indicated.

*Bakken Shale* means the Bakken Shale oil play in the Williston Basin and can include the Upper Three Forks formation.

*Barrel* means one barrel of petroleum products that equals 42 U.S. gallons.

*BBtu* means one billion BTUs.

*BBtu/d* means one billion BTUs per day.

*Bcfe* means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

*Bcf/d* means one billion cubic feet per day.

*Boe* means barrels of oil equivalent.

*Boe/d* means barrels of oil equivalent per day.

*British Thermal Unit or BTU* means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

*FERC* means the Federal Energy Regulatory Commission.

*Fractionation* means the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane.

*LOE* means lease and other operating expense excluding production taxes, ad valorem taxes and gathering, processing and transportation fees.

*Mbbls* means one thousand barrels.

*Mbbls/d* means one thousand barrels per day.

*Mboe/d* means one thousand barrels of oil equivalent per day.

*Mcf* means one thousand cubic feet.

*Mcfe* means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

*MMbbls* means one million barrels.

*MMboe* means one million barrels of oil equivalent.

*MMBtu* means one million BTUs.

*MMBtu/d* means one million BTUs per day.

*MMcf* means one million cubic feet.

*MMcf/d* means one million cubic feet per day.

*MMcfe* means one million cubic feet of gas equivalent using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

*MMcfe/d* means one million cubic feet of gas equivalent per day using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

*NGLs* means natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

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## PART I

*In this report, WPX (which includes WPX Energy, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as we, us or our. We also sometimes refer to WPX as the Company or WPX Energy.*

*Throughout this report we incorporate by reference certain information in parts of other documents filed with the Securities and Exchange Commission (the SEC ). The SEC allows us to disclose important information by referring to it in that manner. Please refer to such documents for information.*

*We are making forward-looking statements in this report. In Item 1A: Risk Factors we discuss some of the risk factors that could cause actual results to differ materially from those stated in the forward-looking statements.*

### Item 1. *Business*

### SEPARATION FROM THE WILLIAMS COMPANIES, INC.

On December 31, 2011 (the Distribution Date ), WPX Energy, Inc. became an independent, publicly traded company as a result of a distribution by The Williams Companies, Inc. ( Williams ) of its shares of WPX to Williams stockholders. On the Distribution Date, Williams stockholders of record as of the close of business on December 14, 2011 (the Record Date ) received one share of WPX common stock for every three shares of Williams common stock held as of the Record Date (the Distribution ). WPX is comprised of Williams former natural gas and oil exploration and production business. Williams Board of Directors approved the distribution of its shares of WPX on November 30, 2011. WPX was incorporated on April 19, 2011 to effect the Distribution. Our registration statement on Form 10 was declared effective by the U.S. Securities and Exchange Commission on December 5, 2011. Our common stock began trading regular-way under the ticker symbol WPX on the New York Stock Exchange on January 3, 2012.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

### WPX ENERGY, INC.

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting our significant natural gas reserves base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our positions in the Bakken Shale oil play in North Dakota and the Marcellus Shale natural gas play in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ( Apco ), which holds oil and gas concessions in Argentina and Colombia and trades on the NASDAQ Capital Market under the symbol APAGF. Our international interests make up approximately four percent of our total proved reserves. In consideration of this percentage, unless specifically referenced herein, the information included in this section relates only to our domestic activity.

We have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. Our proved reserves at December 31, 2011 were 5,265 Bcfe, comprised of 5,070 Bcfe in domestic reserves and 195 Bcfe in net international reserves. Our domestic reserves reflect a mix of 77.4 percent natural gas, 15.4 percent NGLs and 7.2 percent crude oil. During 2011, we replaced our domestic production for all commodities at a rate of 188 percent. For liquids alone, we replaced 488 percent of our crude and NGL production. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

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We report financial results for two segments, our Domestic segment and our International segment. Our International segment primarily consists of Apco. Except as otherwise specifically noted, either by a reference to Apco or to other international operations, the following description of our business is focused on our Domestic segment, which is our dominant segment and which is central to an understanding of our business taken as a whole.

## BUSINESS OVERVIEW

### Our Business Strategy

Our business strategy is to increase shareholder value by finding and developing reserves and producing natural gas, oil and NGLs at costs that generate an attractive rate of return on our investment.

*Efficiently Allocate Capital for Optimal Portfolio Returns*. We expect to allocate capital to the most profitable opportunities in our portfolio based on commodity price cycles and other market conditions, enabling us to continue to grow our reserves and production in a manner that maximizes our return on investment. In determining which drilling opportunities to pursue, we target a minimum after-tax internal rate of return on each operated well we drill of 15 percent. While we have a significant portfolio of drilling opportunities that we believe meet or exceed our return targets even in challenging commodity price environments, we are disciplined in our approach to capital spending and will adjust our drilling capital expenditures based on our level of expected cash flows, access to capital and overall liquidity position. For example, in 2012 we demonstrated our capital discipline by announcing our plans to reduce drilling expenditures in response to prevailing natural gas prices and direct our expenditures toward our oil and liquids-rich areas.

*Continue Our Cost-Efficient Development Approach.* We focus on developing properties where we can apply development practices that result in cost-efficiencies. We manage costs by focusing on establishing large scale, contiguous acreage blocks where we can operate a majority of the properties. We believe this strategy allows us to better achieve economies of scale and apply continuous technological improvements in our operations. We intend to replicate these cost-efficient approaches in our recently acquired growth positions in the Bakken Shale and the Marcellus Shale.

*Pursue Strategic Acquisitions with Significant Resource Potential*. We have a history of acquiring undeveloped properties that meet our disciplined return requirements and other acquisition criteria to expand upon our existing positions as well as acquiring undeveloped acreage in new geographic areas that offer significant resource potential. This is illustrated by our recent acquisitions in the Bakken Shale and the Marcellus Shale. We expect to opportunistically acquire acreage positions in new areas where we feel we can establish significant scale and replicate our cost-efficient development approach.

*Target a More Balanced Commodity Mix in Our Production Profile*. With our Bakken Shale acquisition in December 2010 and our liquids-rich Piceance Basin assets, we have a significant drilling inventory of oil- and liquids-rich opportunities that we intend to develop rapidly in order to achieve a more balanced commodity mix in our production. We refer to the Piceance Basin as liquids-rich because our proved reserves in that basin consist of wet, as opposed to dry, gas and have a significant liquids component. We will continue to pursue other oil- and liquids-rich organic development and acquisition opportunities that meet our investment returns and strategic criteria.

*Maintain Substantial Financial Liquidity and Manage Commodity Price Sensitivity*. We plan to maintain substantial liquidity through a mix of cash on hand and availability under our Credit Facility. In addition, we have engaged and will continue to engage in commodity derivative hedging activities to maintain a degree of cash flow stability. Typically, we target hedging approximately 50 percent of expected revenue from domestic production during a current calendar year in order to strike an

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appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. At December 31, 2011, our estimated domestic natural gas production revenues were 53 percent hedged for 2012. Estimated domestic oil production revenues were 66 percent hedged for 2012 and 10 percent hedged for 2013 as of the same date.

## SIGNIFICANT PROPERTIES

Our principal areas of operation are the Piceance Basin, Bakken Shale, Marcellus Shale, Powder River Basin, San Juan Basin and, through our ownership of Apco, Colombia and Argentina.

*Piceance Basin*

We entered the Piceance Basin in May 2001 with the acquisition of Barrett Resources and since that time have grown to become the largest natural gas producer in Colorado. Our Piceance Basin properties currently comprise our largest area of concentrated development drilling.

During 2011, we operated an average of 11 drilling rigs in the basin, including nine in the Piceance Valley and two in the Piceance Highlands. In the current commodity price environment, we expect a reduced number of rigs in 2012. We had an average of 679 MMcf/d of net gas production from our Piceance Basin properties along with an average of 27.1 Mbbls/d of NGLs and 2.3 Mbbls/d of condensate recovered from our Piceance Basin properties. Capital expenditures were approximately $739 million which included the completion of 385 gross (361 net) wells in 2011. A large majority of our natural gas production in this basin currently is gathered through a system owned by Williams Partners L.P. ( Williams Partners ) and delivered to markets through a number of interstate pipelines.

The Piceance Basin is located in northwestern Colorado. Our operations in the basin are divided into two areas: the Piceance Valley and the Piceance Highlands. Our Piceance Valley area includes operations along the Colorado River valley and is the more developed area where we have produced consistent, repeatable results. The Piceance Highlands, which are those areas at higher elevations above the river valley, contain vast development opportunities that position us well for growth in the future as infrastructure expands and efficiency improvements continue. Our development activities in the basin are primarily focused on the Williams Fork section within the Mesaverde formation. The Williams Fork can be over 2,000 feet in thickness and is comprised of several tight, interbedded, lenticular sandstone lenses encountered at depths ranging from 7,000 to 13,000 feet. In order to maximize producing rates and recovery of natural gas reserves we must hydraulically fracture the well using a fluid system comprised of 99 percent water and sand. Advancements in completion technology, including the use of microseismic data have enabled us to more effectively stimulate the reservoir and recover a greater percentage of the natural gas in place. We are currently evaluating deeper horizons such as the Mancos and Niobrara shale formations, which have the potential to provide additional development opportunities.

*Bakken Shale*

In December 2010 we acquired leasehold positions of approximately 85,800 net acres in the Williston Basin. All of our properties in the Williston Basin are on the Fort Berthold Indian Reservation in North Dakota, where we are the primary operator. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results as well as the publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation, the primary target for all of the well locations in our current drilling inventory.

During 2011, we operated an average of 3.4 rigs on our Bakken properties and we had an average of 5.2 Mboe/d of net production from our Bakken Shale wells. Capital expenditures were approximately $288 million which included the completion of 25 gross (20 net) wells in 2011.

We are developing oil reserves through horizontal drilling in the Middle Bakken and plan to develop the Upper Three Forks shale oil formations utilizing drilling and completion expertise gained in part through experience in our other basins. Based on our subsurface geological analysis, we believe that our position lies in the area of the basin s greatest potential recovery for Bakken formation oil. Currently our Bakken Shale development has the highest incremental returns of any of our drilling programs.

Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada, covering approximately 202,000 square miles, of which 143,000 square miles are in the United States. The basin produces oil and natural gas from numerous producing horizons including the Bakken, Three Forks, Madison and Red River formations. A report issued by the U.S. Geological Survey in April 2008 classified the Bakken formation as the largest continuous oil accumulation ever assessed by it in the contiguous United States.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members referred to as the Upper, Middle and Lower Bakken shales. The formation ranges up to 150 feet thick and is a continuous and structurally simple reservoir. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The Middle Bakken, which varies in composition from a silty dolomite to shaly limestone or sand, serves as the productive formation and is a critical reservoir for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock that may add incremental reserves to our existing leasehold positions. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation has recently been exploited utilizing the same horizontal drilling and advanced completion techniques as the Bakken development. Drilling in the Three Forks formation began in mid-2008 and a number of operators are currently drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation and the evolution of completion techniques, we believe that most of our Williston Basin acreage is prospective in the Three Forks formation. We are in the process of completing a well drilled in the Three Forks formation.

Our acreage in the Bakken Shale, as well as a portion of our acreage in the Piceance Basin and Powder River Basin, is leased to us by or with the approval of the federal government or its agencies, and is subject to federal authority, National Environmental Policy Act ( NEPA ), the Bureau of Indian Affairs or other regulatory regimes that require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands. These regulatory regimes impose obligations on the federal government and governmental agencies that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals and could result in certain instances in the cancellation of existing leases.

*Marcellus Shale*

Our Marcellus Shale acreage is located in four principal areas of the play within Pennsylvania: the northeast portion of the play in and near Susquehanna County; the southwest in and around Westmoreland County; centrally in Clearfield and Centre Counties and the east in Columbia County. (See Management s Discussion and Analysis of Financial Condition and Results of Operations Overview of the years ended December 31, 2011 and 2010 for discussion of a $50 million write-off of leasehold costs associated with approximately 65 percent of our total Columbia County acreage. Our total Columbia County acreage represents 21 percent of our total undeveloped acreage in the Marcellus Shale). We have expanded our position since our entry into the Marcellus Shale in 2009, both organically and through third-party acquisitions. We are the primary operator on our acreage for all four areas and plan to develop our acreage using horizontal drilling and completion expertise in part gained through operations in our other basins. Our most established area is in Westmoreland County but in the future we expect our most significant drilling area to be in Susquehanna County. A third party gathering system providing the main trunkline out of the area was completed in December 2011.

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During 2011, we operated an average of four rigs on our Marcellus Shale properties and we had an average of 15 MMcfe/d of net production from our Marcellus Shale wells. Production levels were hampered for much of 2011 awaiting the completion of a third party gathering system. Capital expenditures were approximately $274 million which included the completion of 38 gross (19 net) wells in 2011. At year end, another 27 gross wells were awaiting completion.

The Marcellus Shale formation is the most expansive shale gas play in the United States, spanning six states in the northeastern United States. The Marcellus Shale is a black, organic rich shale formation located at depths between 4,000 and 8,500 feet, covering approximately 95,000 square miles at an average net thickness of 50 feet to 300 feet.

*Powder River Basin*

We own a large position in coal bed methane reserves in the Powder River Basin and together with our co-developer, Lance Oil & Gas Company Inc., control 912,056 acres, of which our ownership represents 411,440 net acres. We share operations with our co-developer and both companies have extensive experience producing from coal formations in the Powder River Basin dating from its earliest commercial growth in the late 1990s. The natural gas produced is gathered by a system owned by our co-developer.

During 2011, we had an average of 227 MMcfe/d of net production from our Powder River Basin properties. Capital expenditures were approximately $57 million which included the completion of 524 gross (226 net) wells in 2011. The majority of these wells were drilled in prior years and completed the dewatering process in 2011. In 2012, we expect our expenditures to be significantly less than our 2011 expenditures.

Our Powder River Basin properties are located in northeastern Wyoming. Our development operations in this basin are focused on coal bed methane plays in the Big George and Wyodak project areas. Initially, coal bed methane wells typically produce water in a process called dewatering. This process lowers pressure, allowing the natural gas to flow to the wellbore. As the coal seam pressure declines, the wells begin producing methane gas at an increasing rate. As the wells mature, the production peaks, stabilizes and then begins declining. The average life of a coal bed methane well in the Powder River Basin ranges from five to 15 years. While these wells generally produce at much lower rates with fewer reserves attributed to them when compared to conventional natural gas wells in the Rocky Mountains, they also typically have higher drilling success rates and lower capital costs.

The coal seams that we target in the Powder River Basin have been extensively mapped as a result of a variety of natural resource development projects that have occurred in the region. Industry data from over 25,000 wellbores drilled through the Ft. Union coal formation allows us to determine critical data such as the aerial extent, thickness, gas saturation, formation pressure and relative permeability of the coal seams we target for development, which we believe significantly reduces our dry hole risk.

*San Juan Basin*

We acquired our San Juan Basin properties as part of Williams acquisition of Northwest Energy in 1983. These properties represented the first major area of natural gas exploration and development activities for Williams. Our San Juan Basin properties include holdings across the basin producing primarily from the Mesa Verde, Fruitland Coal and Mancos shale gas formations. We operate two units in New Mexico (Rosa and Cox Canyon) as well as several non-unit properties, and we operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We also own properties operated by other operators in New Mexico and Colorado. Approximately 60 percent of our net San Juan Basin production comes from our operated properties.

During 2011, we had an average of 136 MMcfe/d of net production from our San Juan Basin properties. Capital expenditures were approximately $58 million which included the completion of 56 gross (33 net) wells.

According to a September 2010 Wood Mackenzie report, the San Juan Basin is one of the oldest and most prolific coal bed methane plays in the world. The Fruitland coal bed extends to depths of approximately 4,200 ft

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with net thickness ranging from zero to 100 feet. The Mesa Verde play is the top producing tight gas play in the basin with total thickness ranging from 500 to 2,500 feet. The Mesa Verde is underlain by the upper Mancos Shale and overlain by the Lewis Shale.

*International*

We hold an approximate 69 percent controlling equity interest in Apco. Apco in turn owns interests in several blocks in Argentina, including concessions in the Neuquén, Austral, Northwest and San Jorge Basins, and in three exploration permits in Colombia, with its primary properties consisting of the Neuquén and Austral Basin concessions. Apco s oil and gas reserves are approximately 57 percent oil, 39 percent natural gas and four percent liquefied petroleum gas.

During 2011, Apco had an average of 12.9 Mboe/d of net production.

Apco participated in the drilling of 33 wells operated by its partners in 2011 of which Apco spent, for its direct ownership interest, approximately $39 million in capital expenditures.

The government of Argentina has implemented price control mechanisms over the sale of natural gas and over gasoline prices in the country. As a result of these controls and other actions by the Argentine government, sales price realizations for natural gas and oil sold in Argentina are generally below international market levels and are significantly influenced by Argentine governmental actions.

We also hold additional international assets in northwest Argentina that are not part of Apco s holdings.

*Other Properties*

Our other holdings are comprised of assets in the Barnett Shale located in north central Texas, gas reserves in the Green River Basin of southwest Wyoming, and interests in the Arkoma Basin in southeastern Oklahoma.

During 2011, we operated one rig on our other properties and we had an average of 78 MMcfe/d of net production from continuing operations from our other properties. Capital expenditures were approximately $118 million, which included the completion of 212 gross (34 net) wells on our other properties in 2011. In 2012, we expect our capital expenditures to be significantly less than 2011 for these basins.

Our Barnett Shale properties produce predominately natural gas from horizontal wells, where we are the primary operator and have drilled more than 200 wells. We are seeking offers to sell our Arkoma Basin properties, which include 79,110 net acres, including 22,728 undeveloped net acres. Such properties were reported as discontinued operations in our consolidated financial statements and comprised less than one percent of our assets and are not included in our average daily net production amount for 2011.

**Acquisitions and Divestitures**

Our acquisitions during 2011 consisted of miscellaneous leasehold purchases with minimal associated production. We may from time to time dispose of producing properties and undeveloped acreage positions if we believe they no longer fit into our strategic plan.

**Title to Properties**

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. In addition, leases on Native American reservations are subject to Bureau of Indian Affairs and other approvals unique to those locations. As is customary in the industry in the case of undeveloped properties, a limited investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which can result in litigation and delay or loss of our ability to realize the benefits of our leases.

**Reserves and Production Information**

We have significant oil and gas producing activities primarily in the Rocky Mountain, northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. Proved reserves and revenues related to international activities are approximately four percent and three percent, respectively, of our total international and domestic proved reserves and revenues from producing activities. Accordingly, unless specifically stated otherwise, the information in the remainder of this Item 1 relates only to the oil and gas activities in the United States.

*Oil and Gas Reserves*

Our proved reserves were previously reported on a combined product basis, however, with the increase in the significance of our oil and natural gas liquids reserves estimates, we have separated our reserves estimates into natural gas, natural gas liquids and oil. As a result, previously reported periods have been recast to reflect current presentation. The following table sets forth our estimated domestic net proved developed and undeveloped reserves expressed by product and on a gas equivalent basis for the reporting periods December 31, 2011, 2010 and 2009.

| | As of December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Gas (MMcf) | NGL (Mbbls) | Oil (Mbbls) | Equivalent (MMcfe)(2) | % |
| Proved Developed | 2,497,291 | 72,139 | 13,555 | 3,011,457 | 59% |
| Proved Undeveloped | 1,485,644 | 61,938 | 33,568 | 2,058,676 | 41% |
| Total Proved-Domestic | 3,982,935 | 134,077 | 47,123 | 5,070,133 | |

| | As of December 31, 2010(1) | | | | |
|---|---|---|---|---|---|
| | Gas (MMcf) | NGL (Mbbls) | Oil (Mbbls) | Equivalent (MMcfe)(2) | % |
| Proved Developed | 2,368,465 | 48,688 | 3,973 | 2,684,431 | 58% |
| Proved Undeveloped | 1,545,739 | 47,169 | 20,302 | 1,950,567 | 42% |
| Total Proved-Domestic | 3,914,204 | 95,857 | 24,275 | 4,634,998 | |

| | As of December 31, 2009(1) | | | | |
|---|---|---|---|---|---|
| | Gas (MMcf) | NGL (Mbbls) | Oil (Mbbls) | Equivalent (MMcfe)(2) | % |
| Proved Developed | 2,298,420 | 31,570 | 1,914 | 2,499,329 | 56% |
| Proved Undeveloped | 1,771,279 | 32,463 | 2,728 | 1,982,422 | 44% |
| Total Proved-Domestic | 4,069,699 | 64,033 | 4,642 | 4,481,751 | |

(1) NGL amounts for 2010 and 2009 were previously reported as part of natural gas production volumes at the wellhead.
(2) Oil and NGLs converted to MMcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

The following table sets forth our estimated domestic net proved reserves for our largest areas of activity expressed by product and on a gas equivalent basis as of December 31, 2011.

| | As of December 31, 2011 | | | |
|---|---|---|---|---|
| | Gas (MMcf) | NGL (MBbls) | Oil (MBbls) | Equivalent (MMcfe) |
| Piceance Basin | 2,689,440 | 128,594 | 5,760 | 3,495,567 |
| Bakken Shale | 19,838 | 3,910 | 40,627 | 287,056 |
| Marcellus Shale | 141,865 | | | 141,865 |
| Powder River Basin | 343,795 | 20 | 50 | 344,214 |
| San Juan Basin | 531,080 | 581 | 66 | 534,963 |
| Other | 256,917 | 972 | 620 | 266,468 |
| Total Proved-Domestic | 3,982,935 | 134,077 | 47,123 | 5,070,133 |

We prepare our own reserves estimates and approximately 99 percent of our reserves are audited by Netherland, Sewell & Associates, Inc. ( NSAI ).

We have not filed on a recurring basis estimates of our total proved net oil, NGL, and gas reserves with any U.S. regulatory authority or agency other than with the U.S. Department of Energy and the SEC. The estimates furnished to the Department of Energy have been consistent with those furnished to the SEC.

Our 2011 year-end estimated proved reserves were derived using an average price of $3.64 per Mcf, an average oil price of $86.87 per barrel and average NGL price of $49.30 per barrel. These prices were calculated from the 12-month average, first-of-the-month price for the applicable indices for each basin as adjusted for locational price differentials. During 2011, we added 1,065 Bcfe of additions to our proved reserves. During 2011, we participated in the drilling of 1,241 gross wells at a capital cost of approximately $1,461 million.

*Reserves estimation process*

Our reserves are estimated by deterministic methods using an appropriate combination of production performance analysis and volumetric techniques. The proved reserves for economic undrilled locations are estimated by analogy or volumetrically from offset developed locations. Reservoir continuity and lateral persistence of our tight-sands, shale and coal bed methane reservoirs is established by combinations of subsurface analysis and analysis of 2D and 3D seismic data and pressure data. Understanding reservoir quality may be augmented by core samples analysis.

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate by providing supporting information such as pricing, capital costs, expenses, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our reserves analysis department. The reserves analysis department s responsibilities also include performing an internal review of reserves data for reasonableness and accuracy, working with NSAI and the asset teams to successfully complete the reserves audit, finalizing the year-end reserves report and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. Early in the year, we begin with a review of the existing internal processes and controls to identify where improvements can be made from the prior year s reporting cycle. Later in the year, the reserves staffs from the asset teams submit their preliminary reserves data to the reserves analysis department. After review by the reserves analysis department, the data is submitted to NSAI to begin their audits. After this point, reserves data analysis and further review are conducted and iterated between the asset teams, reserves analysis department and NSAI. In early December, reserves are reviewed with senior management. The process concludes upon receipt of the audit letter from NSAI.

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The reserves estimates resulting from our process are subjected to both internal and external controls to promote transparency and accuracy of the year-end reserves estimates. Our internal reserves analysis team is independent and does not work within an asset team or report directly to anyone on an asset team. The reserves analysis department provides detailed independent review and extensive documentation of the year-end process. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated. The compensation of our reserves analysis team is not linked to reserves additions or revisions.

Approximately 99 percent of our total year-end 2011 domestic proved reserves estimates were audited by NSAI. When compared on a well-by-well basis, some of our estimates are greater and some are less than the NSAI estimates. NSAI is satisfied with our methods and procedures in preparing the December 31, 2011 reserves estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserves audit is the Director of Reserves and Production Services. The Director s qualifications include 29 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in Physical Sciences from the University of Houston and membership in the American Association of Petroleum Geologists and The Society of Petroleum Engineers.

*Proved undeveloped reserves*

The majority of our reserves is concentrated in unconventional tight-sands, shale and coal bed gas reservoirs. We use available geoscience and engineering data to establish drainage areas and reservoir continuity beyond one direct offset from a producing well, which provides additional proved undeveloped reserves. Inherent in the methodology is a requirement for significant well density of economically producing wells to establish reasonable certainty. In general, fields where producing wells are less concentrated, only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification. No new technologies were used to assign proved undeveloped reserves.

At December 31, 2011, our proved undeveloped reserves were 2,059 Bcfe, an increase of 108 Bcfe over our December 31, 2010 proved undeveloped reserves estimate of 1,951 Bcfe. During 2011, 321 Bcfe of our December 31, 2010 proved undeveloped reserves were converted to proved developed reserves at a cost of $587 million. An additional 306 Bcfe was added due to the development of unproved locations. As of 2011 year-end, we have reclassified a net 502 Bcfe from proved to probable reserves due to the SEC five year rules. These reclassified reserves are predominately in the Piceance Basin where we have a large inventory of drilling locations and have been offset by the combined additions and revisions of 671 Bcfe of proved undeveloped drilling locations.

All proved undeveloped locations are scheduled to be spud within the next five years.

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**Oil and Gas Properties and Production, Production Prices and Production Costs**

Our production sales data was previously reported on a combined product basis, however, with the increase in the significance of our oil and natural gas liquids production, we have separated our production sales data into natural gas, natural gas liquids and oil. As a result, previously reported periods have been recast to reflect current presentation. The following table summarizes our net production sales for the years indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| **Production Sales Data:** | **2011** | **2010** | **2009** |
| **Natural Gas (MMcf)** | | | |
| U.S. | | | |
| Piceance Basin | 247,700 | 230,279 | 245,946 |
| Other(1) | 165,820 | 162,497 | 171,591 |
| International(2) | 7,389 | 7,088 | 6,789 |
| Total | 420,909 | 399,864 | 424,326 |
| **NGLs (Mbbls)** | | | |
| U.S. | | | |
| Piceance Basin | 9,902 | 8,003 | 4,644 |
| Other(1) | 156 | 53 | 77 |
| International(2) | 183 | 162 | 154 |
| Total | 10,241 | 8,218 | 4,875 |
| **Oil (Mbbls)** | | | |
| U.S. | 2,676 | 857 | 803 |
| International(2) | 2,054 | 1,980 | 1,994 |
| Total | 4,730 | 2,837 | 2,797 |
| Combined Equivalent Volumes (MMcfe)(2) (3) | 510,735 | 466,194 | 470,354 |
| Combined Equivalent Volumes (Mboe) | 85,122 | 77,699 | 78,392 |
| Average Daily Combined Equivalent Volumes (MMcfe/d) (3) | | | |
| U.S. | | | |
| Piceance Basin | 855 | 775 | 761 |
| Other(1) | 487 | 448 | 474 |
| International(2) | 57 | 55 | 51 |
| Total | 1,399 | 1,278 | 1,286 |

(1) Excludes production from our Arkoma Basin operations which were classified as held for sale and reported as discontinued operations and comprised less than one percent of our total production.

(2) Includes approximately 69 percent of Apco s production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

(3) Amounts for 2010 and 2009 have been recalculated using a conversion ratio for our NGLs of 6 to 1 as these were previously reported in natural gas volumes.

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The following tables summarize our domestic sales price and cost information for the years indicated.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Realized average price per unit(1):** | | | |
| Natural gas, without hedges (per Mcf) | $ 3.51 | $ 3.73 | $ 3.12 |
| Impact of hedges (per Mcf) | 0.79 | 0.84 | 1.47 |
| Natural gas, with hedges (per Mcf) | $ 4.30 | $ 4.57 | $ 4.59 |
| NGL, without hedges (per Bbl) | $ 40.17 | $ 35.02 | $ 28.80 |
| Impact of hedges (per Bbl) | | | |
| NGL, with hedges (per Bbl) | $ 40.17 | $ 35.02 | $ 28.80 |
| Oil, without hedges (per Bbl) | $ 85.00 | $ 66.32 | $ 47.39 |
| Impact of hedges (per Bbl) | 0.38 | | |
| Oil, with hedges (per Bbl) | $ 85.38 | $ 66.32 | $ 47.39 |
| Price per Boe, without hedges(2) | $ 25.53 | $ 24.24 | $ 19.63 |
| Price per Boe, with hedges(2) | $ 29.53 | $ 28.71 | $ 27.82 |
| Price per Mcfe, without hedges(2) | $ 4.26 | $ 4.04 | $ 3.27 |
| Price per Mcfe, with hedges(2) | $ 4.92 | $ 4.79 | $ 4.64 |

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations and comprised less than one percent of our total revenues.
(2) Realized average prices reflect realized market prices, net of fuel and shrink.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Expenses per Mcfe(1):** | | | |
| Operating expenses: | | | |
| Lifting costs and workovers | $ 0.46 | $ 0.42 | $ 0.37 |
| Facilities operating expense | 0.04 | 0.13 | 0.14 |
| Other operating and maintenance | 0.05 | 0.05 | 0.04 |
| Total LOE | $ 0.55 | $ 0.60 | $ 0.55 |
| Gathering, processing and transportation charges | 1.02 | 0.73 | 0.60 |
| Taxes other than income | 0.24 | 0.24 | 0.18 |
| Production cost | $ 1.81 | $ 1.57 | $ 1.33 |
| General and administrative | $ 0.56 | $ 0.55 | $ 0.54 |
| Depreciation, depletion and amortization | $ 1.89 | $ 1.92 | $ 1.93 |

(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations.

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**Productive Oil and Gas Wells**

The table below summarizes 2011 productive wells by area.*

| | Gas Wells (Gross) | Gas Wells (Net) | Oil Wells (Gross) | Oil Wells (Net) |
|---|---|---|---|---|
| Piceance Basin | 4,278 | 3,908 | | |
| Bakken Shale | | | 59 | 35 |
| Marcellus Shale | 54 | 29 | | |
| Powder River Basin | 6,760 | 3,007 | | |
| San Juan Basin | 3,289 | 888 | | |
| Other(1) | 1,834 | 551 | | |
| Total | 16,215 | 8,383 | 59 | 35 |

* We use the term gross to refer to all wells or acreage in which we have at least a partial working interest and net to refer to our ownership represented by that working interest.

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties. Our Arkoma Basin operations are classified as held for sale and reported as discontinued operations and comprised less than one percent of our assets.

At December 31, 2011, there were 221 gross and 110 net producing wells with multiple completions.

**Developed and Undeveloped Acreage**

The following table summarizes our leased acreage as of December 31, 2011.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Gross Acres | Net Acres |
| Piceance Basin | 121,101 | 96,668 | 155,538 | 116,300 | 276,639 | 212,968 |
| Bakken Shale | 36,494 | 31,054 | 58,591 | 55,059 | 95,085 | 86,113 |
| Marcellus Shale(1) | 12,831 | 7,026 | 125,861 | 99,950 | 138,692 | 106,976 |
| Powder River Basin | 609,995 | 277,726 | 302,061 | 133,715 | 912,056 | 411,441 |
| San Juan Basin | 240,091 | 121,925 | 2,100 | 1,576 | 242,191 | 123,501 |
| Other(2) | 153,114 | 84,870 | 240,310 | 155,737 | 393,424 | 240,607 |
| Total | 1,173,626 | 619,269 | 884,461 | 562,337 | 2,058,087 | 1,181,606 |

(1) Approximately 21 percent of our undeveloped net acres in the Marcellus Shale are located in Columbia County. During 2011, we recorded a $50 million write-off of leasehold costs associated with approximately 65 percent of our Columbia County acreage that we no longer plan to develop.

(2) Other includes Barnett Shale, Arkoma and Green River Basins, other Williston Basin acreage and miscellaneous smaller properties. Our Arkoma Basin operations were classified as held for sale and reported as discontinued operations and comprised less than one percent of our assets.

**Drilling and Exploratory Activities**

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2011, 2010 and 2009.

The following table summarizes the number of domestic wells drilled for the periods indicated.

| | 2011 | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| | Gross Wells | Net Wells | Gross Wells | Net Wells | Gross Wells | Net Wells |
| Piceance Basin | 385 | 361 | 398 | 360 | 363 | 334 |
| Bakken Shale | 25 | 20 | | | n/a | n/a |
| Marcellus Shale | 36 | 17 | 8 | 3 | 2 | 1 |
| Powder River Basin | 523 | 225 | 531 | 244 | 540 | 244 |
| San Juan Basin | 56 | 33 | 43 | 15 | 87 | 50 |
| Other | 212 | 34 | 177 | 38 | 199 | 36 |
| Productive, development | 1,237 | 690 | 1,157 | 660 | 1,191 | 665 |
| Productive, exploration | 2 | 2 | | | 1 | |
| Total Productive | 1,239 | 692 | 1,157 | 660 | 1,192 | 665 |
| Dry, development | 2 | 1 | 5 | 4 | 2 | 1 |
| Dry, exploration | | | | | 2 | 1 |
| Total Drilled | 1,241 | 693 | 1,162 | 664 | 1,196 | 667 |

(1) Other includes Barnett Shale, Arkoma and Green River Basins and miscellaneous smaller properties.
In 2011, we drilled two gross nonproductive development wells (in Marcellus Shale and in Powder River Basin) and one net nonproductive development wells. Total gross operated wells drilled were 758 in 2011, 656 in 2010 and 472 in 2009.

**Present Activities**

At December 31, 2011, we had 25 gross (17 net) wells in the process of being drilled.

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**Scheduled Lease Expirations**

*Domestic.* The table below sets forth, as of December 31, 2011, the gross and net acres scheduled to expire over the next several years. The acreage will not expire if we are able to establish production by drilling wells on the lease prior to the expiration date. We expect to hold substantially all of the Bakken and Marcellus Shale acreage by drilling prior to its expiration. Approximately 59% of the acreage shown in the table below as Other in 2012 through 2013 consists of our Arkoma Basin operations which are currently held for sale.

| | 2012 | 2013 | 2014 | 2015 + | Total |
|---|---|---|---|---|---|
| Piceance Basin | 4,777 | 2,878 | 489 | 2,522 | 10,666 |
| Bakken Shale | 9,620 | 43,362 | 370 | 1,639 | 54,991 |
| Marcellus Shale | 890 | 35,839 | 6,579 | 43,674 | 86,982 |
| Powder River Basin | 8,106 | 15,382 | 1,081 | 66 | 24,635 |
| San Juan Basin | | | | | |
| Other | 11,692 | 13,523 | 28,760 | 81,037 | 135,012 |
| Total (Gross Acres) | 35,085 | 110,984 | 37,279 | 128,938 | 312,286 |

| | 2012 | 2013 | 2014 | 2015+ | Total |
|---|---|---|---|---|---|
| Piceance Basin | 2,104 | 2,182 | 649 | 2,104 | 7,039 |
| Bakken Shale | 9,224 | 42,835 | 370 | 1,535 | 53,964 |
| Marcellus Shale | 787 | 27,934 | 3,974 | 38,369 | 71,064 |
| Powder River Basin | 2,715 | 7,474 | 547 | 52 | 10,788 |
| San Juan Basin | | | | | |
| Other | 9,761 | 12,487 | 27,887 | 81,033 | 131,168 |
| Total (Net Acres) | 24,591 | 92,912 | 33,427 | 123,093 | 274,023 |

*International.* In general, all of our concessions have expiration dates of either 2025 or 2026, except for two concessions that expire beyond 2030 and four that expire in 2015 and 2016. With respect to these four we are negotiating ten year extensions for which we have contractual rights. These four concessions represent approximately 169,000 acres net to Apco or approximately 116,000 acres net to WPX based on our 69% ownership in Apco. Our remaining properties in Argentina and Colombia are all exploration permits or exploration contracts that have much shorter terms and on which we have made exploration investment commitments that must be completed. These areas will expire in 2012 and 2013 unless discoveries are made. There are opportunities to extend exploration terms for a year with good technical justification. We can either declare the portions of these blocks where we have made discoveries commercial and convert that acreage to a concession or exploitation acreage with a specified term for production of 25 to 35 years, or relinquish a portion or the balance of the acreage if we are not willing to make further exploration commitments.

**Gas Management**

Our sales and marketing activities include the sale of our natural gas, NGL and oil production, in addition to third party purchases and subsequent sales to Williams Partners for fuel and shrink gas. We do not expect to continue to provide fuel and shrink gas services to Williams Partners midstream business on a long-term basis. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related hedges. We also sell natural gas purchased from working interest owners in operated wells and other area third party producers. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in oil and gas revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

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**Delivery Commitments**

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. The Piceance, being our largest producing basin, generates ample production to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of natural gas is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure. This obligation expires in 2014.

**Purchase Commitments**

In December 2010, we agreed to buy up to 200,000 MMBtu/d of natural gas at Transco Station 515 (Marcellus Shale) priced at market prices from a third party. Purchases under the 12-year contract began in January 2012. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

**Seasonality**

Generally, the demand for natural gas decreases during the spring and fall months and increases during the winter months and in some areas during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Conversely, during extreme weather events such as blizzards, hurricanes, or heat waves, pipeline systems can become temporary constraints to supply meeting demand thus amplifying localized price spikes. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the warmer months. This can lessen seasonal demand fluctuations. World weather and resultant prices for liquefied natural gas can also affect deliveries of competing liquefied natural gas into this country from abroad, affecting the price of domestically produced natural gas. In addition, adverse weather conditions can also affect our production rates or otherwise disrupt our operations.

**Hedging Activity**

To manage the commodity price risk and volatility associated with owning producing natural gas, NGL and crude oil properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in Management s Discussion and Analysis of Financial Condition and Results of Operations.

**Customers**

Oil, NGLs and natural gas production is sold through our sales and marketing activities to a variety of purchasers under various length contracts ranging from one day to multi-year at market based prices. Our third party customers include other producers, utility companies, power generators, banks, marketing and trading companies and midstream service providers. In 2011, natural gas sales to BP Energy Company accounted for approximately 11 percent of our consolidated revenues. We believe that the loss of one or more of our current natural gas, oil or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

**REGULATORY MATTERS**

The oil and natural gas industry is extensively regulated by numerous federal, state, local and foreign authorities, including Native American tribes in the United States. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and NGLs are not currently regulated and are made at market prices.

*Drilling and Production*

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities including seasonal wildlife closures;
- the employment of tribal members or use of tribal owned service businesses;
- the rates of production or allowables;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, oil and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells, or to limit the number of locations we can drill.

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Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where we operate. Most states have an administrative agency that requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

*Natural Gas Sales and Transportation*

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing natural gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with them . The FERC s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under the FERC s current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting natural gas to point-of-sale locations.

*Oil Sales and Transportation*

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

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Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

*Operation on Native American Reservations*

A portion of our leases are, and some of our future leases may be, regulated by Native American tribes. In addition to regulation by various federal, state, and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and BLM, and the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are often subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements, or delays in obtaining necessary approvals or permits pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

## ENVIRONMENTAL MATTERS

Our operations are subject to numerous federal, state, local, Native American tribal and foreign laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act ( CERCLA ), the Clean Water Act ( CWA ) and the Clean Air Act ( CAA ). These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental

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obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, in March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes the addition of Energy Extraction Activities to its enforcement priorities list. According to the EPA s website, some energy extraction activities, such as new techniques for oil and gas extraction and coal mining, pose a risk of pollution of air, surface waters and ground waters if not properly controlled. To address these concerns, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements. This initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

*Hazardous Substances and Wastes.* CERCLA, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act ( RCRA ) generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. An environmental organization recently petitioned the EPA to reconsider certain RCRA exemptions for exploration and production wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the CWA, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

*Waste Discharges.* The CWA and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. In 2007, 2008 and 2010, we received three separate information requests from the EPA pursuant to Section 308 of the CWA. The information requests required us to provide the EPA with information about releases at three of our facilities and our compliance with spill prevention, control and countermeasure requirements. We have responded to these information requests and no proceeding or enforcement actions have been initiated. We believe that our operations are in substantial compliance with the CWA.

On February 16, 2012, the EPA issued the final 2012 construction general permit ( CGP ) for stormwater discharges from construction activities involving more than one acre, which will provide coverage for a five year period. The 2012 CGP modifies the prior CGP to implement the new Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The new rule includes new and more stringent restrictions on erosion and sediment control, pollution prevention and stabilization, although a numeric turbidity limit for certain larger construction sites has been stayed as of January 4, 2011.

*Air Emissions.* The CAA and associated state laws and regulations restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases ( GHGs ) have been developed by the EPA and may increase the costs of compliance for some facilities.

*Oil Pollution Act.* The Oil Pollution Act of 1990, as amended ( OPA ) and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

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*National Environmental Policy Act.* Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ( NEPA ). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

*Endangered Species Act.* The Endangered Species Act ( ESA ) restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

*Worker Safety.* The Occupational Safety and Health Act ( OSHA ) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

*Safe Drinking Water Act.* The Safe Drinking Water Act ( SDWA ) and comparable state statutes restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state s environmental authority. These regulations may increase the costs of compliance for some facilities.

*Hydraulic Fracturing.* We ordinarily use hydraulic fracturing as a means to maximize the productivity of our oil and gas wells in all of the domestic basins in which we operate. Our net acreage position in the basins in which hydraulic fracturing is utilized total approximately 770,000 acres and represents approximately 93% of our domestic proved undeveloped oil and gas reserves. Although average drilling and completion costs for each basin will vary, as will the cost of each well within a given basin, on average approximately 31% of the drilling and completion costs for each of our wells for which we use hydraulic fracturing is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget.

The protection of groundwater quality is extremely important to us. We follow applicable standard industry practices and legal requirements for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), which conduct many inspections during operations that include hydraulic fracturing. Industry standards and legal requirements for groundwater protection focus on five principal areas: (i) pressure testing of well construction and integrity, (ii) lining of pits used to hold water and other fluids used in the drilling process isolated from surface water and groundwater, (iii) casing and cementing practices for wells to ensure separation of the production zone from groundwater, (iv) disclosure of the chemical content of fracturing liquids, and (v) setback requirements as to the location of waste disposal areas. The legal requirements relating to the protection of surface water and groundwater vary from state to state and there are also federal regulations and guidance that apply to all domestic drilling. In addition, the American Petroleum Institute publishes industry standards and guidance for hydraulic fracturing and the protection of surface water and groundwater. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing.

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In addition to the required use of and specifications for casing and cement in well construction, we observe regulatory requirements and what we consider best practices to ensure wellbore integrity and full isolation of any underground aquifers and protection of surface waters. These include the following:

- Prior to perforating the production casing and hydraulic fracturing operations, the casing is pressure tested.

- Before the fracturing operation commences, all surface equipment is pressure tested, which includes the wellhead and all pressurized lines and connections leading from the pumping equipment to the wellhead. During the pumping phases of the hydraulic fracturing treatment, specialized equipment is utilized to monitor and record surface pressures, pumping rates, volumes and chemical concentrations to ensure the treatment is proceeding as designed and the wellbore integrity is sound. Should any problem be detected during the hydraulic fracturing treatment, the operation is shut down until the problem is evaluated, reported and remediated.

- As a means to protect against the negative impacts of any potential surface release of fluids associated with the hydraulic fracturing operation, special precautions are taken to ensure proper containment and storage of fluids. For example, any earthen pits containing non-fresh water must be lined with a synthetic impervious liner. These pits are tested regularly, and in certain sensitive areas have additional leak detection systems in place. At least two feet of freeboard, or available capacity, must be present in the pit at all times. In addition, earthen berms are constructed around any storage tanks, any fluid handling equipment, and in some cases around the perimeter of the location to contain any fluid releases. These berms are considered to be a "secondary" form of containment and serve as an added measure for the protection of groundwater.

- We conduct baseline water monitoring in many of the basins in which we use hydraulic fracturing:

- In Colorado, baseline water monitoring may be required by the Colorado Oil and Gas Conservation Commission ("COGCC") or BLM as a condition of approval for the drilling permit, but otherwise it is not a requirement. Industry worked with the Colorado Oil & Gas Association as well as the COGCC to adopt a voluntary baseline groundwater quality sampling program. We have committed to the program that went into effect in August 2011.

- In the Barnett Shale, and with landowner approval, we perform water monitoring of fresh water wells within an agreed upon distance on a voluntary basis, even though not required by state regulation.

- In Pennsylvania, we perform baseline water monitoring pursuant to Pennsylvania Department of Environmental Protection requirements.

- There are currently no regulatory requirements to conduct baseline water monitoring in the Bakken Shale or the San Juan Basin. We plan to begin voluntarily conducting water monitoring in the Bakken Shale. The majority of our assets in the San Juan Basin are on federal lands, and there are few cases where water wells are within one to two miles of our wells, which is outside the range that we would typically sample.

Once a pipe is set in place, cement is pumped into the well where it hardens and creates a permanent, isolating barrier between the steel casing pipe and surrounding geological formations. This aspect of the well design essentially eliminates a "pathway" for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. Furthermore, in the basins in which we conduct hydraulic fracturing, the hydrocarbon bearing formations are separated from any usable underground aquifers by thousands of feet of impermeable rock layers. This wide separation serves as a protective barrier, preventing any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones.

In addition, the vendors we employ to conduct hydraulic fracturing are required to monitor all pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis and data is recorded to ensure protection of groundwater.

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The cement and steel casing used in well construction can have rare failures. Any failure in isolation is reported to the applicable oil and gas regulatory body. A remediation procedure is written and approved and then completed on the well before any further operations or production is commenced. Possible isolation failures may result from:

*Improper cementing work.* This can create conditions in which hydraulic fracturing fluids and other natural occurring substances can migrate into the surrounding geological formation. Production casing cementing tops and cement bond effectiveness are evaluated using either a temperature log or an acoustical cement bond log prior to any completion operations. If the cement bond or cement top is determined to be inadequate for zone isolation, remedial cementing operations are performed to fill any voids and re-establish integrity. As part of this remedial operation, the casing is again pressure tested before fracturing operations are initiated.

*Initial casing integrity failure.* The casing is pressure tested prior to commencing completion operations. If the test fails due to a compromise in the casing, the applicable oil and gas regulatory body will be notified and a remediation procedure will be written, approved and completed before any further operations are conducted. In addition, casing pressures are monitored throughout the fracturing treatment and any indication of failure will result in an immediate shutdown of the operation.

*Well failure or casing integrity failure during production*. Loss of wellbore integrity can occur over time even if the well was correctly constructed due to downhole operating environments causing corrosion and stress. During production, the bradenhead, casing and tubing pressures are monitored and a casing failure can be identified and evaluated. Remediation could include placing additional cement behind casing, installing a casing patch, or plugging and abandoning the well, if necessary.

*Fluid leakoff during the fracturing process*. Fluid leakoff can occur during hydraulic fracturing operations whereby some of the hydraulic fracturing fluid flows through the artificially created fractures into the micropore or pore spaces within the formation, existing natural factures in the formation, or small fractures opened into the formation by the pressure in the induced fracture. Fluid leakoff is accounted for in the volume design of nearly every fracturing job and pump-in tests are often conducted prior to fracturing jobs to estimate the extent of fluid leakoff. In certain situations, a very fine grain sand is added in the initial part of the treatment to seal-off any small fractures of micropore spaces and mitigate fluid leak-off.

Approximately 99% of hydraulic fracturing fluids are made up of water and sand. We utilize major hydraulic fracturing service companies whose research departments conduct ongoing development of greener chemicals that are used in fracturing. We evaluate, test, and where appropriate adopt those products that are more environmentally friendly. We have also chosen to participate in a voluntary fracturing chemical registry that is a public website: www.fracfocus.org at which interested persons can find out information about fracturing fluids. This registry is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission and provides our industry with an avenue to voluntarily disclose chemicals used in the hydraulic fracturing process. The Company registered with the FracFocus Chemical Disclosure Registry in April 2011 and began uploading data when the registry went live on April 11, 2011. To date, we have loaded data on more than 430 wells. We plan to add all wells fractured since January 1, 2011 to the site. Consistent with other industry participants, we are not planning to add data on wells drilled prior to 2011. The information included on this website is not incorporated by reference in this Annual Report on Form 10-K .

In 2011, we used 100% recycled water for our hydraulic fracturing operations in our largest area of development, the Piceance basin. This recycling process lessens the demand on local natural water resources. Any water that is recovered in our operations that is not used for our hydraulic fracturing operations is safely disposed in accordance with the State and Federal rules and regulations in a manner that does not impact underground aquifers and surface waters. In the Marcellus we use a blend of recycled water from our hydraulic fracturing operations with water from natural sources.

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Despite our efforts to minimize impacts on the environment from hydraulic fracturing activities, in light of the volume of our hydraulic fracturing activities, we have occasionally been engaged in litigation and received requests for information, notices of alleged violation, and citations related to the activities of our hydraulic fracturing vendors, none of which has resulted in any material costs or penalties.

Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate are considering Fracturing Responsibility and Awareness of Chemicals Act ( FRAC Act ) bills and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, the EPA s interpretation without formal rule making has been challenged and industry groups have filed suit challenging the EPA s interpretation. If the EPA prevails in this lawsuit, its interpretation could result in enforcement actions against service providers or companies that used diesel products in the hydraulic fracturing process or could require such providers or companies to conduct additional studies regarding diesel in the groundwater. Furthermore, the State of Colorado, in response to an EPA request, has asked companies operating in Colorado, including us, to report whether diesel products were used in the hydraulic fracturing process from 2004 to 2009. In response to this inquiry we consulted our service providers and reported to the State of Colorado that at least nine wells were subject to hydraulic fracturing utilizing fluids that contained chemical products that contained diesel fuel as a component. The State of Colorado may conduct additional investigations related to this inquiry. Any enforcement actions or requirements of additional studies or investigations by the EPA or the State of Colorado could increase our operating costs and cause delays or interruptions of our operations.

On October 21, 2011, the EPA announced its intention to propose regulation by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The results of this study, expected in late 2012, could result in additional regulations, which could lead to operational burdens similar to those described above. In connection with the EPA study, we have received a request for information from the EPA for 52 of our wells located in various basins that have been hydraulically fractured. The requested information covers well design, construction and completion practices, among other things. We understand that similar requests were sent to eight other companies that own or operate wells that utilized hydraulic fracturing.

In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011. The report concludes that the risk of fracturing fluids contaminating drinking water sources through fractures in the shale formations is remote. It also states that development of the nation s shale resources has produced major economic benefits. The report includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The Government Accountability Office is also examining the environmental impacts of produced water and the

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Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. The United States Department of the Interior is also considering whether to impose disclosure requirements or other mandates for hydraulic fracturing on federal land.

Several states, including Pennsylvania, Texas, Colorado, North Dakota and New Mexico, have adopted or are considering adopting, regulations that could restrict or impose additional requirements related to hydraulic fracturing. For example, on December 13, 2011, the Texas Railroad Commission adopted Statewide Rule 29, which requires public disclosure of the chemicals that operators use during hydraulic fracturing in Texas for all operators that receive a permit on or after February 1, 2012. Pennsylvania also requires that detailed information be disclosed regarding the hydraulic fracturing fluids, including but not limited to, a list of chemical additives, volume of each chemical added, and list of chemicals in the material safety data sheets. Since June 2009, Colorado has required all operators to maintain a chemical inventory by well site for each chemical product used downhole or stored for use downhole during drilling, completion and workover operations, including fracture stimulation in an amount exceeding 500 pounds during any quarterly reporting period. Colorado adopted its final hydraulic fracturing chemical disclosure rules on December 13, 2011. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

In addition, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities, while some state and local governments in the Marcellus Shale have considered or imposed temporary moratoria on drilling operations using hydraulic fracturing until further study of the potential environmental and human health impacts by the EPA or the relative state agencies are completed. Additionally, publicly operated treatment works facilities in Pennsylvania have ceased taking wastewater from hydraulic fracturing operations, and we are now recycling this wastewater and utilizing it in subsequent hydraulic fracturing operations. At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

*Global Warming and Climate Change.* Recent scientific studies have suggested that emissions of GHGs, including carbon dioxide and methane, may be contributing to warming of the earth s atmosphere. Both houses of Congress have previously considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The EPA has begun to regulate GHG emissions. On December 7, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public heath and the environment. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. EPA issued a final rule that went into effect in 2011 that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions. On November 30, 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage, and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. We are required to report our GHG emissions under this rule but are not subject to GHG permitting requirements. Several of the EPA s GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact our operations. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources and may increase our litigation risk

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for such claims. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

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 adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

*Foreign Operations.* Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries. For example, the Argentine Department of Energy and the government of the provinces in which Apco s oil and gas producing concessions are located have environmental control policies and regulations that must be adhered to when conducting oil and gas exploration and exploitation activities. Future environmental regulation of certain aspects of our operations in Argentina and Columbia that are currently unregulated and changes in the laws or regulations could materially affect our financial condition and results of operations.

## COMPETITION

We compete with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

In our gas management services business, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

## EMPLOYEES

At December 31, 2011, we had approximately 1,200 full-time employees.

## FINANCIAL INFORMATION ABOUT SEGMENTS

See Item 8 Financial Statements and Supplementary Data Notes to Consolidated Financial Statements Note 18 of our Notes to Consolidated Financial Statements for financial information with respect to our segments revenues, profits or losses and total assets.

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## FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Item 8 Financial Statements and Supplementary Data Note 18 of our Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also, see Note 18 of the our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

## WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We make available free of charge through our website, *www.wpxenergy.com/investors*, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, other reports filed under the Securities Exchange Act of 1934 ( Exchange Act ) and all amendments to those reports simultaneously or as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Our reports are also available free of charge on the SEC s website, *www.sec.gov*. You may inspect and copy our reports at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the Public Reference Room. Also available free of charge on our website are the following corporate governance documents:

- Amended and Restated Certificate of Incorporation
- Restated Bylaws
- Corporate Governance Guidelines
- Code of Business Conduct, which is applicable to all WPX Energy directors and employees, including the principal executive officer, the principal financial officer and the principal accounting officer
- Audit Committee Charter
- Compensation Committee Charter
- Nominating and Governance Committee Charter

All of our reports and corporate governance documents may also be obtained without charge by contacting Investor Relations, WPX Energy, Inc., One Williams Center, Tulsa, Oklahoma 74172.

We maintain an Internet site at www.wpxenergy.com. We do not incorporate our Internet site, or the information contained on that site or connected to that site, into this Annual Report on Form 10-K.

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

## FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT

## FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF

## THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain matters contained in this Annual Report on Form 10-K include forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. These forward-looking statements relate to anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. In some cases, forward-looking statements can be identified by various forms of words such as anticipates, believes, seeks, could, may, should, continues, estimates, expects, for

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intends, might, goals, objectives, targets, planned, potential, projects, scheduled, will or other similar expressions. These forw statements are based on management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Seasonality of our business; and
- Natural gas, crude oil and NGLs prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;

Development of alternative energy sources;

The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations (including climate change legislation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;

Changes in maintenance and construction costs;

Changes in the current geopolitical situation;

Our exposure to the credit risk of our customers;

Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;

Risks associated with future weather conditions;

Acts of terrorism; and

Other factors described in Management s Discussion and Analysis of Financial Condition and Results of Operations and Business.

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All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements set forth above. Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. Forward-looking statements speak only as of the date they are made. We disclaim any obligation to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments, except to the extent required by applicable laws. If we update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors are described in Risk Factors.

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## RISK FACTORS

*You should carefully consider each of the following risks, which we believe are the principal risks that we face and of which we are currently aware, and all of the other information in this report. Some of the risks described below relate to our business, while others relate to our separation from Williams. Other risks relate principally to the securities markets and ownership of our common stock. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could suffer materially and adversely. In that case, the trading price of our common stock could decline, and you might lose all or part of your investment.*

### Risks Related to Our Business

*Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.*

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, capital contributions or borrowings from Williams and sales of assets. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of natural gas and oil and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our natural gas and oil production or reserves, and in some areas a loss of properties.

*Failure to replace reserves may negatively affect our business.*

The growth of our business depends upon our ability to find, develop or acquire additional natural gas and oil reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not always be able to find, develop or acquire additional reserves at acceptable costs. If natural gas or oil prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

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

Our past success rate for drilling projects should not be considered a predictor of future commercial success. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The new wells we drill or participate in may not be commercially productive, and we may not recover all or any portion of our investment in wells we drill or participate in. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed, canceled or rendered unprofitable or less profitable than anticipated as a result of a variety of other factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, supplies, skilled labor, capital or transportation;

- Equipment failures or accidents;

- Adverse weather conditions, such as floods or blizzards;

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- Title and lease related problems;
- Limitations in the market for natural gas and oil;
- Unexpected drilling conditions or problems;
- Pressure or irregularities in geological formations;
- Regulations and regulatory approvals;
- Changes or anticipated changes in energy prices; or
- Compliance with environmental and other governmental requirements.

We expect to invest approximately 60 percent of our drilling capital during 2012 in two relatively new unconventional projects, the Bakken Shale in western North Dakota and the Marcellus Shale in Pennsylvania. Due to limited production history from the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in those projects.

*If natural gas and oil prices decrease, we may be required to take write-downs of the carrying values of our natural gas and oil properties.*

Accounting rules require that we review periodically the carrying value of our natural gas and oil properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our natural gas and oil properties. A writedown constitutes a non-cash charge to earnings. For example, as a result of annual and interim assessments for impairments of our proved properties and due to significant declines in forward natural gas prices, we recorded impairments of capitalized costs of certain natural gas properties of $547 million in 2011 and $678 million in 2010. In addition to those long-lived assets for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For the other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately eight percent could be at risk for impairment if forward prices across all future periods decline by approximately 12 to 14 percent, on average, as compared to the forward prices at December 31, 2011. A substantial portion of the remaining carrying value of these other assets (primarily related to assets in the Piceance basin) could be at risk for impairment if forward prices across all future periods decline by at least 24 percent, on average, as compared to the prices at December 31, 2011. We may incur impairment charges for these or other properties in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

*Estimating reserves and future net revenues involves uncertainties. Decreases in natural gas and oil prices, or negative revisions to reserve estimates or assumptions as to future natural gas and oil prices may lead to decreased earnings, losses or impairment of natural gas and oil assets.*

Reserve estimation is a subjective process of evaluating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are proved reserves are those estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings.

*The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.*

Approximately 41 percent of our total estimated proved reserves at December 31, 2011 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

*The present value of future net revenues from our proved reserves will not necessarily be the same as the value we ultimately realize of our estimated natural gas and oil reserves.*

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our natural gas and oil properties will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

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

*Certain of our domestic undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.*

The majority of our acreage in the Marcellus Shale and Bakken Shale is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If we do not extend our leases and our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, natural gas and oil prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory and lease issues.

*Prices for natural gas, oil and NGLs are volatile, and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain our existing business.*

Our revenues, operating results, future rate of growth and the value of our business depend primarily upon the prices of natural gas, oil and NGLs. Price volatility can impact both the amount we receive for our products and the volume of products we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money under our Credit Facility or raise additional capital.

The markets for natural gas, oil and NGLs are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, oil and NGLs;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- Variations in local market conditions (basis differential);
- The price and availability of other types of fuels;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and quantity of foreign imports of natural gas and oil;

- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas and oil markets;
- The overall economic environment;
- The credit of participants in the markets where products are bought and sold; and
- The adoption of regulations or legislation relating to climate change.

*Our business depends on access to natural gas, oil and NGL transportation systems and facilities.*

The marketability of our natural gas, oil and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Bakken Shale and Marcellus Shale or that we will be able to obtain sufficient transportation capacity on economic terms.

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A lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

*We may have excess capacity under our firm transportation contracts, or the terms of certain of those contracts may be less favorable than those we could obtain currently.*

We have entered into contracts for firm transportation that may exceed our transportation needs. Any excess transportation commitments will result in excess transportation costs that could negatively affect our results of operations. In addition, certain of the contracts we have entered into may be on terms less favorable to us than we could obtain if we were negotiating them at current rates, which also could negatively affect our results of operations.

*We have limited control over activities on properties we do not operate, which could reduce our production and revenues.*

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator s breach of the applicable agreements could reduce our production and revenues or increase our costs. As of December 31, 2011, we were not the operator of approximately 14 percent of our total domestic net production. Apco generally has outside-operated interests in its properties. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the operator s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

*We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.*

Our portfolio of derivative and other energy contracts includes wholesale contracts to buy and sell natural gas, oil and NGLs that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our business, we often extend credit to our counterparties. We are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty s obligation is inadequate, we will suffer a loss. Downturns in the economy or disruptions in the global credit markets could cause more of our counterparties to fail to perform than we expect.

*Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.*

The systems we use to quantify commodity price risk associated with our businesses might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified. Furthermore, no single hedging arrangement can adequately address all commodity price risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract s counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of derivatives through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for natural gas, oil and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for natural gas, oil or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

*The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.*

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act ) was enacted. The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The final impact of the Dodd-Frank Act on our hedging activities is uncertain at this time due to the requirement that the SEC and the Commodities Futures Trading Commission ( CFTC ) promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. These new rules and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts or reduce the availability of derivatives. Although we believe the derivative contracts that we enter into should not be impacted by position limits and should be exempt from the requirement to clear transactions through a central exchange or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

Depending on the rules and definitions adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

*We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.*

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers and counterparties creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

*We face competition in acquiring new properties, marketing natural gas and oil and securing equipment and trained personnel in the natural gas and oil industry.*

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and oil and securing equipment and trained personnel. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

*Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.*

There are operational risks associated with drilling for, production, gathering, transporting, storage, processing and treating of natural gas and oil and the fractionation and storage of NGLs, including:

- Hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines, pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas (including sour gas), oil, NGLs, brine or industrial chemicals;
- Operator error;
- Pollution and environmental risks;
- Fires, explosions and blowouts;
- Risks related to truck and rail loading and unloading; and
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

*We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.*

We are not fully insured against all risks inherent to our business, including environmental accidents. We do not maintain insurance in the type and amount to cover all possible risks of loss.

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We currently maintain excess liability insurance that covers us, our subsidiaries and certain of our affiliates for legal and contractual liabilities arising out of bodily injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability.

Although we maintain property insurance on certain physical assets that we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets. In addition, certain perils may be excluded from coverage or sub-limited. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. We may elect to self insure a portion of our risks. All of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured it could adversely affect our operations and financial condition.

In addition, any insurance company that provides coverage to us may experience negative developments that could impair their ability to pay any of our claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

*Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.*

Regulators and legislators continue to take a renewed look at accounting practices, financial and reserves disclosures and companies relationships with their independent public accounting firms and reserves consultants. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact of that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations and financial condition.

*Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.*

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States, principally in Argentina and Colombia. The economic, political and legal conditions and regulatory environment in the countries in which we have interests or in which we might pursue acquisition or investment opportunities present risks that are different from or greater than those in the United States. These risks include delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, including with respect to the prices we realize for the commodities we produce and sell. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain nonrecourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments.

Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.

*Our operating results might fluctuate on a seasonal and quarterly basis.*

Our revenues can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

*Our debt agreements impose restrictions on us that may limit our access to credit and adversely affect our ability to operate our business.*

Our Credit Facility contains various covenants that restrict or limit, among other things, our ability to grant liens to support indebtedness, merge or sell substantially all of our assets, make investments, loans or advances and enter into certain hedging agreements, make certain distributions, incur additional debt and enter into certain affiliate transactions. In addition, our Credit Facility contains financial covenants and other limitations with which we will need to comply and which may limit our ability to borrow under the facility. Similarly, the indenture governing the Notes restricts our ability to grant liens to secure certain types of indebtedness and merge or sell substantially all of our assets. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired.

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance our debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

*Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations.*

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers and reduced access to credit markets. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

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*We are subject to risks associated with climate change.*

There is a growing belief that emissions of greenhouse gases ( GHGs ) may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

In addition, legislative and regulatory responses related to GHGs and climate change create the potential for financial risk. The U.S. Congress has previously considered legislation and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

Numerous states have announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. Also in 2009, the EPA finalized a GHG emission standard for mobile sources. On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. On November 8, 2010, the EPA also issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule requires reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA by March 2012 under this rule. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. Several of the EPA s GHG rules are being challenged in pending court proceedings, and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

The recent actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

*Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities that could exceed current expectations.*

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations inherent in drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- Clean Air Act ( CAA ) and analogous state laws, which impose obligations related to air emissions;

- Clean Water Act ( CWA ), and analogous state laws, which regulate discharge of wastewaters and storm water from some our facilities into state and federal waters, including wetlands;

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Comprehensive Environmental Response, Compensation, and Liability Act ( CERCLA ), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;

Resource Conservation and Recovery Act ( RCRA ), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities;

National Environmental Policy Act ( NEPA ), which requires federal agencies to study likely environment impacts of a proposed federal action before it is approved, such as drilling on federal lands;

Safe Drinking Water Act ( SDWA ), which restricts the disposal, treatment or release of water produced or used during oil and gas development;

Endangered Species Act ( ESA ), and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and

Oil Pollution Act ( OPA ) of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulation of above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including the U.S. Environmental Protection Agency ( EPA ), the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which includes the addition of Energy Extraction Activities to its enforcement priorities list. To address its concerns regarding the pollution risks raised by new techniques for oil and gas extraction and coal mining, the EPA is developing an initiative to ensure that energy extraction activities are complying with federal environmental requirements. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Our business may be adversely affected by increased costs due to stricter pollution control equipment requirements or liabilities resulting from non-compliance with required operating or other regulatory permits.

Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and any new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

Our exploration and production operations outside the United States are subject to various types of regulations similar to those described above imposed by the governments of the countries in which we operate, and may affect our operations and costs within those countries.

*Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.*

Legislation has been introduced in the United States Congress called the Fracturing Responsibility and Awareness of Chemicals Act (the FRAC Act ) to amend the SDWA to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as require disclosure of the chemical constituents of the fluids used in the fracturing process. Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations in order to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. At this time, it is not clear what action, if any, the United States Congress will take on the FRAC Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. On October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a report on hydraulic fracturing in August 2011, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The U.S. Government Accountability Office is also examining the environmental impacts of produced water and the White House Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. Several states have also adopted or considered legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic

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fracturing, including states in which we operate (e.g., Wyoming, Pennsylvania, Texas, Colorado, North Dakota and New Mexico). The U.S. Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

*Our ability to produce gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.*

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations, particularly with respect to our Marcellus Shale, San Juan Basin, Bakken Shale and Piceance Basin operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

*Legal and regulatory proceedings and investigations relating to the energy industry, and the complex government regulations to which our businesses are subject, have adversely affected our business and may continue to do so. The operation of our businesses might also be adversely affected by changes in regulations or in their interpretation or implementation, or the introduction of new laws, regulations or permitting requirements applicable to our businesses or our customers.*

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation or increased permitting requirements. Current legal proceedings or other matters against us, including environmental matters, suits, regulatory appeals, challenges to our permits by citizen groups and similar matters, might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations might be revised or reinterpreted, new laws, regulations and permitting requirements might be adopted or become applicable to us, our facilities, our customers, our vendors or our

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service providers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, several ruptures on third party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed, including new regulations covering gathering pipelines that have not previously been subject to regulation. Such reforms, if adopted, could significantly increase our costs.

*Certain of our properties, including our operations in the Bakken Shale, are located on Native American tribal lands and are subject to various federal and tribal approvals and regulations, which may increase our costs and delay or prevent our efforts to conduct planned operations.*

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management ( BLM ) and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to gas and oil operations on Native American tribal lands. These regulations and approval requirements relate to such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. In addition, if our relationships with any of the relevant Native American tribes were to deteriorate, we could face significant risks to our ability to continue the projected development of our leases on Native American tribal lands. One or more of these factors may increase our costs of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct, our natural gas or oil development and production operations on such lands.

*Tax laws and regulations may change over time, including the elimination of, or changing the timing of, certain federal income tax deductions currently available with respect to oil and gas exploration and development*

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws, treaties and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions at the time that the filings were made. If these laws, treaties or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws, treaties and regulations, it could have a material adverse effect on us.

Among the changes contained in President Obama s budget proposal for fiscal year 2013, released by the White House on February 13, 2012, is the elimination of, or changing the timing of, certain U.S. federal income tax provisions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current expensing of intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate, or change the timing of, certain tax deductions that are currently available with respect to oil and gas exploration and development. Changes to such federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including the imposition of, or increases in production, severance, or similar taxes) could negatively affect our financial condition and results of operations.

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*Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.*

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- properties we acquire may be subject to burdens on title that we were not aware of at the time of acquisition or that interfere with our ability to hold the property for production;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

*Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.*

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

*Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.*

We rely on Williams for certain services necessary for us to be able to conduct our business. Williams may outsource some or all of these services to third parties, and a failure of all or part of Williams relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on Williams and others as service providers and on Williams outsourcing relationships, and our limited ability to control certain costs, could have a material adverse effect on our business, results of operations and financial condition.

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Certain of our accounting, information technology, application development and help desk services are currently provided by Williams outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which Williams outsourcing providers may provide services to us present similar risks of business operations located outside of the United States, including risks of interruption of business, war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States.

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*Our assets and operations can be adversely affected by weather and other natural phenomena.*

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, we have been unable to obtain insurance on commercially reasonable terms, or insurance has not been available at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

*Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.*

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute natural gas, oil, or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

**Risks Related to Our Recent Separation from Williams**

*We may not realize the potential benefits from our separation from Williams.*

We may not realize the benefits that we anticipated from our separation from Williams. These benefits include the following:

- allowing our management to focus its efforts on our business and strategic priorities;
- enhancing our market recognition with investors;
- providing us with direct access to the debt and equity capital markets;
- improving our ability to pursue acquisitions through the use of shares of our common stock as consideration; and
- enabling us to allocate our capital more efficiently.

We may not achieve the anticipated benefits from our separation for a variety of reasons. For example, the process of separating our business from Williams and operating as an independent public company may distract our management from focusing on our business and strategic priorities. In addition, although we will have direct access to the debt and equity capital markets following the separation, we may not be able to issue debt or equity on terms acceptable to us or at all. The availability of shares of our common stock for use as consideration for acquisitions also will not ensure that we will be able to successfully pursue acquisitions or that the acquisitions will be successful. Moreover, even with equity compensation tied to our business we may not be able to attract and retain employees as desired. We also may not fully realize the anticipated benefits from our separation if any of the matters identified as risks in this Risk Factors section were to occur. If we do not realize the anticipated benefits from our separation for any reason, our business may be materially adversely affected.

*Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.*

The historical financial information that we have included in this report may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. We were not operated, as a

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separate, stand-alone company for the historical periods presented. The costs and expenses reflected in our historical financial information include an allocation for certain corporate functions historically provided by Williams, including executive oversight, cash management and treasury administration, financing and accounting, tax, internal audit, investor relations, payroll and human resources administration, information technology, legal, regulatory and government affairs, insurance and claims administration, records management, real estate and facilities management, sourcing and procurement, mail, print and other office services, and other services, that may be different from the comparable expenses that we would have incurred had we operated as a stand-alone company. These allocations were based on what we and Williams considered to be reasonable reflections of the historical utilization levels of these services required in support of our business. We have not adjusted our historical financial information to reflect changes that will occur in our cost structure and operations as a result of our transition to becoming a stand-alone public company, including changes in our employee base, potential increased costs associated with reduced economies of scale, the provision of letters of credit in lieu of Williams guarantees to support certain contracts and increased costs associated with the SEC reporting and the NYSE requirements. Therefore, our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future. For additional information, see Selected Historical Financial Data and Management s Discussion and Analysis of Financial Condition and Results of Operations, and our financial statements and related notes included elsewhere in this report.

*Our costs may increase as a result of operating as a public company, and our management will be required to devote substantial time to complying with public company regulations.*

We have historically operated our business as a segment of a public company. As a stand-alone public company, we may incur additional legal, accounting, compliance and other expenses that we have not incurred historically. We are now obligated to file with the SEC annual and quarterly information and other reports that are specified in Section 13 and other sections of the Exchange Act. We are required to ensure that we have the ability to prepare financial statements that are fully compliant with all SEC reporting requirements on a timely basis. In addition, we are subject to other reporting and corporate governance requirements, including certain requirements of the NYSE, and certain provisions of Sarbanes-Oxley and the regulations promulgated thereunder, which will impose significant compliance obligations upon us.

Sarbanes-Oxley, as well as new rules subsequently implemented by the SEC and the NYSE, have imposed increased regulation and disclosure and required enhanced corporate governance practices of public companies. We are committed to maintaining high standards of corporate governance and public disclosure, and our efforts to comply with evolving laws, regulations and standards in this regard are likely to result in increased marketing, selling and administrative expenses and a diversion of management s time and attention from revenue-generating activities to compliance activities. These changes require a significant commitment of additional resources. We may not be successful in implementing these requirements and implementing them could materially adversely affect our business, results of operations and financial condition. In addition, if we fail to implement the requirements with respect to our internal accounting and audit functions, our ability to report our operating results on a timely and accurate basis could be impaired. If we do not implement such requirements in a timely manner or with adequate compliance, we might be subject to sanctions or investigation by regulatory authorities, such as the SEC or the NYSE. Any such action could harm our reputation and the confidence of investors and clients in our company and could materially adversely affect our business and cause our share price to fall.

*We will continue to depend on Williams to provide us with certain services for our business; the services that Williams provides to us may not be sufficient to meet our needs, and we may have difficulty finding replacement services or be required to pay increased costs to replace these services after our agreements with Williams expire.*

Certain transition services required by us for the operation of our business are currently provided by Williams and its subsidiaries, including services related to finance and accounting, payroll and human resources administration, information technology, real estate and facilities management, sourcing and procurement, mail,

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print and other office services. We have entered into agreements with Williams related to the separation of our business operations from Williams, including a transition services agreement. The services provided under the transition services agreement commenced on the distribution date and will terminate upon the earlier of (i) one year after the distribution date or (ii) sixty days notice by either party. In addition, Williams may immediately terminate any of the services it provides to us under the transition services agreement if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law. We believe it is necessary for Williams to provide services for us under the transition services agreement to facilitate the efficient operation of our business in our transition to a stand alone public company. We are, as a result, depending on Williams for services. While these services are being provided to us by Williams, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them will be limited. After the expiration or termination of the transition services agreement, we may not be able to replace these services or enter into appropriate third-party agreements on terms and conditions, including cost, comparable to those that we receive from Williams under the transition services agreement. Although we intend to replace portions of the services currently provided by Williams, we may encounter difficulties replacing certain services or be unable to negotiate pricing or other terms as favorable as those we currently have in effect.

*Our agreements with Williams require us to assume the past, present, and future liabilities related to our business and may be less favorable to us than if they had been negotiated with unaffiliated third parties.*

We negotiated all of our agreements with Williams as a wholly-owned subsidiary of Williams. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us. Pursuant to the separation and distribution agreement, we have assumed all past, present and future liabilities (other than tax liabilities which will be governed by the tax sharing agreement as described herein) related to our business, and we will agree to indemnify Williams for these liabilities, among other matters. Such liabilities include unknown liabilities that could be significant. The allocation of assets and liabilities between Williams and us may not reflect the allocation that would have been reached between two unaffiliated parties.

*We may increase our debt or raise additional capital in the future, which could affect our financial health, and may decrease our profitability.*

We may increase our debt or raise additional capital in the future, subject to restrictions in our debt agreements. If our cash flow from operations is less than we anticipate, or if our cash requirements are more than we expect, we may require more financing. However, debt or equity financing may not be available to us on terms acceptable to us, if at all. If we incur additional debt or raise equity through the issuance of our preferred stock, the terms of the debt or our preferred stock issued may give the holders rights, preferences and privileges senior to those of holders of our common stock, particularly in the event of liquidation. The terms of the debt may also impose additional and more stringent restrictions on our operations than we currently have. If we raise funds through the issuance of additional equity, your ownership in us would be diluted. If we are unable to raise additional capital when needed, it could affect our financial health, which could negatively affect your investment in us.

*Our tax sharing agreement with Williams may limit our ability to take certain actions and may require us to indemnify Williams for significant tax liabilities*.

Under the tax sharing agreement, we agreed to take reasonable action or reasonably refrain from taking action to ensure that the spin-off qualifies for tax-free status under section 355 and section 368(a)(1)(D) of the Internal Revenue Code of 1986 (the Code ) (unless the IRS issues other guidance that can be relied on conclusively to the effect that a contemplated matter or transaction would not jeopardize such tax-free status of the spin-off ). We also agreed to various other covenants in the tax sharing agreement intended to ensure the tax-free status of the spin-off. These covenants restrict our ability to sell assets outside the ordinary course of business, to issue or sell additional common stock (including securities convertible into our common stock), or to enter into certain other corporate transactions. For example, we may not enter into any transaction that would cause us to undergo either a 50% or greater change in the ownership of our voting stock or a 50% or greater change in the ownership (measured by value) of all classes of our stock in transactions considered related to the spin-off.

Further, under the tax sharing agreement, we are required to indemnify Williams against certain tax-related liabilities that may be incurred by Williams (including any of its subsidiaries) relating to the spin-off, to the extent caused by our breach of any representations or covenants made in the tax sharing agreement or the separation and distribution agreement, or made in connection with the private letter ruling or the tax opinion that Williams received as a condition to the spin-off. These liabilities include the substantial tax-related liability (calculated without regard to any net operating loss or other tax attribute of Williams) that would result if the spin-off of our stock to Williams stockholders failed to qualify as a tax-free transaction.

*We will not have complete control over our tax decisions and could be liable for income taxes owed by Williams.*

For any tax periods ending on or before the spin-off , we and our U.S. subsidiaries will be included in Williams consolidated group for U.S. federal income tax purposes. In addition, we or one or more of our U.S. subsidiaries may be included in the combined, consolidated or unitary tax returns of Williams or one or more of its subsidiaries for U.S. state or local income tax purposes. Under the tax sharing agreement, for each period in which we or any of our subsidiaries are consolidated or combined with Williams for purposes of any tax return, Williams will prepare a pro forma tax return for us as if we filed our own consolidated, combined or unitary return, except that such pro forma tax return will generally include current income, deductions, credits and losses from us (with certain exceptions), will not include any carryovers or carrybacks of losses or credits and will be calculated without regard to the federal alternative minimum tax. We will reimburse Williams for any taxes shown on the pro forma tax returns, and Williams will reimburse us for any current losses or credits we recognize based on the pro forma tax returns after taking into account any prior related payments or credits. In addition, Williams will effectively control all of our U.S. tax decisions in connection with any Williams consolidated, combined or unitary income tax returns in which we (or any of our subsidiaries) are included. The tax sharing agreement provides that Williams will have sole authority to respond to and conduct all tax proceedings (including tax audits) relating to its tax returns , to prepare and file all consolidated, combined or unitary income tax returns in which we are included (including the making of any tax elections), and to determine the reimbursement amounts in connection with any pro forma tax returns. This arrangement may result in conflicts of interest between Williams and us. For example, under the tax sharing agreement, Williams will be able to choose to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Williams and detrimental to us.

Moreover, notwithstanding the tax sharing agreement, U.S. federal law provides that each member of a consolidated group is liable for the group s entire tax obligation. Thus, to the extent Williams or other members of Williams consolidated group fail to make any U.S. federal income tax payments required by law, we could be liable for the shortfall with respect to periods prior to the spin-off in which we were a member of Williams consolidated group. Similar principles may apply for foreign, state or local income tax purposes where we were included in combined, consolidated or unitary returns with Williams or its subsidiaries for foreign, state or local income tax purposes.

*If there is a determination that the spin-off is taxable for U.S. federal income tax purposes because the facts, assumptions, representations, or undertakings underlying the tax opinion are incorrect or for any other reason, then Williams and its stockholders could incur significant income tax liabilities, and we could incur significant liabilities.*

The spin-off was conditioned on Williams receipt of an opinion of its outside tax advisor reasonably acceptable to the Williams board of directors to the effect that the spin-off would not result in the recognition, for U.S. federal income tax purposes, of income, gain or loss to Williams, and Williams stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of

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fractional shares of WPX common stock that such stockholders would otherwise receive in the distribution. Williams received an opinion from its outside tax advisor to such effect. In addition, Williams received a private letter ruling from the IRS in which the IRS made various rulings, including that the spin-off will not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams and Williams stockholders under section 355 and section 368(a)(1)(D) of the Code, except for cash payments made to stockholders in lieu of fractional shares of WPX common stock that such stockholders would otherwise receive in the distribution. The private letter ruling and opinion relied on certain facts, assumptions, representations and undertakings from Williams and us regarding the past and future conduct of the companies respective businesses and other matters. If any of these facts, assumptions, representations, or undertakings are, or become, incorrect or not otherwise satisfied, Williams and its stockholders may not be able to rely on the private letter ruling or the opinion of its tax advisor and could be subject to significant tax liabilities. In addition, an opinion of counsel is not binding upon the IRS, so, notwithstanding the opinion of Williams tax advisor, the IRS could conclude upon audit that the spin-off is taxable in full or in part if it disagrees with the conclusions in the opinion, or for other reasons, including as a result of certain significant changes in the stock ownership of Williams or us after the spin-off. If the spin-off is determined to be taxable for U.S. federal income tax purposes for any reason, we could incur significant indemnification liabilities provided for in the tax sharing agreement.

*Third parties may seek to hold us responsible for liabilities of Williams that we did not assume in our agreements.*

Third parties may seek to hold us responsible for retained liabilities of Williams. Under our agreements with Williams, Williams agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure you that we will be able to recover the full amount of our losses from Williams.

*Our prior and continuing relationship with Williams exposes us to risks attributable to businesses of Williams*.

Williams is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of Williams that are incurred through a breach of the separation and distribution agreement or any ancillary agreement by Williams or its affiliates other than us, or losses that are attributable to Williams in connection with the spin-off or are not expressly assumed by us under our agreements with Williams. Any claims made against us that are properly attributable to Williams in accordance with these arrangements would require us to exercise our rights under our agreements with Williams to obtain payment from Williams. We are exposed to the risk that, in these circumstances, Williams cannot, or will not, make the required payment.

*Our directors and executive officers who own shares of common stock of Williams, or who hold options to acquire common stock of Williams or other Williams equity-based awards, may have actual or potential conflicts of interest*.

Ownership of shares of common stock of Williams, options to acquire shares of common stock of Williams and other equity-based securities of Williams by certain of our directors and officers, or appear to create, potential conflicts of interest when those directors and officers are faced with decisions that could have different implications for Williams than they do for us.

*The spin-off may expose us to potential liabilities arising out of state and federal fraudulent conveyance laws and legal dividend requirements.*

The spin-off is subject to review under various state and federal fraudulent conveyance laws. Under these laws, if a court in a lawsuit by an unpaid creditor or an entity vested with the power of such creditor (including without limitation a trustee or debtor-in-possession in a bankruptcy by us or Williams or any of our respective subsidiaries) were to determine that Williams or any of its subsidiaries did not receive fair consideration or reasonably equivalent value for distributing our common stock or taking other action as part of the spin-off, or that we or any of our subsidiaries did not receive fair consideration or reasonably equivalent value for incurring indebtedness, including the new debt incurred by us in connection with the spin-off, transferring assets or taking other action as part of the spin-off and, at the time of such action, we, Williams or any of our respective subsidiaries (i) was insolvent or would be rendered insolvent, (ii) had unreasonably small capital with which to carry on its business and all business in which it intended to engage or (iii) intended to incur, or believed it would incur, debts beyond its ability to repay such debts as they would mature, then such court could void the spin-off as a constructive fraudulent transfer. If such court made this determination, the court could impose a number of different remedies, including without limitation, voiding our liens and claims against Williams, or providing Williams with a claim for money damages against us in an amount equal to the difference between the consideration received by Williams and the fair market value of our company at the time of the spin-off.

The measure of insolvency for purposes of the fraudulent conveyance laws will vary depending on which jurisdiction s law is applied. Generally, however, an entity would be considered insolvent if the present fair saleable value of its assets is less than (i) the amount of its liabilities (including contingent liabilities) or (ii) the amount that will be required to pay its probable liabilities on its existing debts as they become absolute and mature. No assurance can be given as to what standard a court would apply to determine insolvency or that a court would determine that we, Williams or any of our respective subsidiaries were solvent at the time of or after giving effect to the spin-off, including the distribution of our common stock.

Under the separation and distribution agreement, each of Williams and we are responsible for the debts, liabilities and other obligations related to the business or businesses which it owns and operates following the consummation of the spin-off. Although we do not expect to be liable for any such obligations not expressly assumed by us pursuant to the separation and distribution agreement, it is possible that a court would disregard the allocation agreed to between the parties, and require that we assume responsibility for obligations allocated to Williams, particularly if Williams were to refuse or were unable to pay or perform the subject allocated obligations.

**Risks Related to Our Common Stock**

*There is not a long market history for our common stock and the market price of our shares may fluctuate widely.*

We cannot predict the prices at which our common stock may trade. The market price of our stock may fluctuate widely,,depending upon many factors, some of which are beyond our control, including those described above in Risks Related to Our Business and the following:

- the failure of securities analysts to cover our common stock after the spin-off or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- strategic actions by us or our competitors;
- announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures or capital commitments;
- variations in our quarterly operating results and those of our competitors;
- general economic and stock market conditions;
- risks related to our business and our industry, including those discussed above;

changes in conditions or trends in our industry, markets or customers;

terrorist acts;

future sales of our common stock or other securities; and

investor perceptions of the investment opportunity associated with our common stock relative to other investment alternatives.

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These broad market and industry factors may materially reduce the market price of our common stock, regardless of our operating performance. In addition, price volatility may be greater if the public float and trading volume of our common stock is low.

*Future sales, or the perception of future sales, of our common stock may depress the price of our common stock.*

We have approximately 197 million shares of common stock outstanding. Sales of significant amounts of our common stock or a perception in the market that such sales will occur may reduce the market price of our common stock. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate.

Also, in the future, we may issue our securities in connection with investments or acquisitions. The amount of shares of our common stock issued in connection with an investment or acquisition could constitute a material portion of our then outstanding shares of our common stock.

*Failure to achieve and maintain effective internal controls in accordance with Section 404 of Sarbanes-Oxley could have a material adverse effect on our business and stock price.*

As a public company, we are required to document and test our internal control procedures in order to satisfy the requirements of Section 404 of Sarbanes-Oxley, which will require annual management assessments of the effectiveness of our internal control over financial reporting and a report by our independent registered public accounting firm that addresses the effectiveness of internal control over financial reporting. During the course of our testing, we may identify deficiencies which we may not be able to remediate in time to meet our deadline for compliance with Section 404. Testing and maintaining internal control can divert our management s attention from other matters that are important to the operation of our business. We also expect the new regulations to increase our legal and financial compliance costs, make it more difficult to attract and retain qualified officers and members of our board of directors, particularly to serve on our audit committee, and make some activities more difficult, time consuming and costly. We may not be able to conclude on an ongoing basis that we have effective internal control over financial reporting in accordance with Section 404 or our independent registered public accounting firm may not be able or willing to issue an unqualified report on the effectiveness of our internal control over financial reporting. If we conclude that our internal control over financial reporting is not effective, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or their effect on our operations because there is presently no precedent available by which to measure compliance adequacy. If either we are unable to conclude that we have effective internal control over financial reporting or our independent auditors are unable to provide us with an unqualified report as required by Section 404, then investors could lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock.

*If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.*

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our stock or if our operating results do not meet their expectations, our stock price could decline.

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*We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.*

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law ( DGCL ). The future payment of dividends will be at the sole discretion of our board of directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our board of directors deems relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

*Provisions of Delaware law and our charter documents may delay or prevent an acquisition of us that stockholders may consider favorable or may prevent efforts by our stockholders to change our directors or our management, which could decrease the value of your shares.*

Section 203 of the DGCL and provisions in our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire us without the consent of our board of directors. These provisions include the following:

- restrictions on business combinations for a three-year period with a stockholder who becomes the beneficial owner of more than 15% of our common stock;
- restrictions on the ability of our stockholders to remove directors;
- supermajority voting requirements for stockholders to amend our organizational documents; and
- a classified board of directors.

Although we believe these provisions protect our stockholders from coercive or otherwise unfair takeover tactics and thereby provide an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our board of directors, these provisions apply even if the offer may be considered beneficial by some stockholders. Further, these provisions may discourage potential acquisition proposals and may delay, deter or prevent a change of control of our company, including through unsolicited transactions that some or all of our stockholders might consider to be desirable. As a result, efforts by our stockholders to change our directors or our management may be unsuccessful.

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

None.

**Item 2.** ***Properties***

Information regarding our properties is included in Item 1 of this report.

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

See Item 8 Financial Statements and Supplementary Data Note 12 of our Notes to Consolidated Financial Statements for the information that is called for by this item.

**Item 4.** ***Mine Safety Disclosures***

Not Applicable

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## PART II

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

Our common stock began trading on January 3, 2012 and is listed on the New York Stock Exchange and is traded under the ticker symbol WPX. . On February 24, 2012, there were 9,034 holders of record of our common stock.

**Item 6. Selected Financial Data**

The following financial data at December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, should be read in conjunction with the other financial information included in Part II, Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data* of this Form 10-K. All other financial data has been prepared from our accounting records. The financial statements included in this Form 10-K may not necessarily reflect our financial position, results of operations and cash flows as if we had operated as a stand-alone public company during all periods presented. Accordingly, our historical results should not be relied upon as an indicator of our future performance.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| | (Millions, except per share amounts) | | | | |
| **Statement of operations data:** | | | | | |
| Revenues | $ 3,988 | $ 4,034 | $ 3,681 | $ 6,184 | $ 4,479 |
| Income (loss) from continuing operations(1) | (272) | (1,275) | 147 | 815 | 191 |
| Income (loss) from discontinued operations(2) | (20) | (8) | (7) | (87) | 146 |
| Net income (loss) | (292) | (1,283) | 140 | 728 | 337 |
| Less: Net income attributable to noncontrolling interests | 10 | 8 | 6 | 8 | 11 |
| Net income (loss) attributable to WPX Energy | $ (302) | $ (1,291) | $ 134 | $ 720 | $ 326 |
| Basic and diluted earnings (loss) per common share: | | | | | |
| Income (loss) from continuing operations | $ (1.43) | $ (6.51) | $ 0.71 | $ 4.09 | $ 0.92 |
| Income (loss) from discontinued operations | $ (0.10) | $ (0.04) | $ (0.03) | $ (0.44) | $ 0.74 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| | (Millions) | | | | |
| **Balance sheet data** | | | | | |
| Notes payable to Williams current(3) | $ | $ 2,261 | $ 1,216 | $ 925 | $ 656 |
| Long-term debt | 1,503 | | | | |
| Total assets | 10,432 | 9,846 | 10,553 | 11,624 | 10,571 |
| Total equity(3) | 5,759 | 4,484 | 5,390 | 5,493 | 4,345 |

(1) Loss from continuing operations for the year ended December 31, 2011 includes $547 million of impairment charges related to producing properties in the Barnett Shale and Powder River basins and costs of acquired unproved reserves in the Powder River basin. Loss from continuing operations for the year ended December 31, 2010 includes $1.7 billion of impairment charges related to goodwill, producing properties in the Barnett Shale and costs of acquired unproved reserves in the Piceance Basin. Income from continuing operations in 2008 includes a $148 million gain related to the sale of a right to an international production payment. See Note 7 of Notes to Consolidated

Financial Statements for further discussion of asset sales, impairments and other accruals in 2011, 2010 and 2009.

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(2) Income (loss) from discontinued operations includes our Arkoma operations which are classified as held for sale and Williams former power business that was substantially disposed of in 2007. The activity in 2011, 2010 and 2009 primarily relates to the Arkoma operations and the remaining indemnity and other obligations related to the former power business. Activity in 2008 reflects a $148 million pre-tax impairment charge related to the producing properties in the Arkoma Basin. Activity in 2007 primarily reflects the operations of the power business and includes a pre-tax gain of $429 million associated with the reclassification of deferred net hedge gains from accumulated other comprehensive income (loss) to earnings based on the determination that the hedged forecasted transactions were probable of not occurring due to the sale of Williams power business. This gain is partially offset by a pre-tax unrealized mark-to-market loss of $23 million, a $37 million loss from operations and $111 million of pre-tax impairments primarily related to the carrying value of certain derivative contracts.

(3) On June 30, 2011, all of our notes payable to Williams were cancelled by Williams. The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in total equity. See Part II, Item 8, *Financial Statements and Supplementary Data* for activity related to our equity at December 31, 2011.

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**Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

**General**

We are an independent natural gas and oil exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on exploiting our significant natural gas reserves base and related NGLs in the Piceance Basin of the Rocky Mountain region, and on developing and growing our position in the Bakken Shale oil play in North Dakota and our Marcellus Shale natural gas position in Pennsylvania. Our other areas of domestic operations include the Powder River Basin in Wyoming and the San Juan Basin in the southwestern United States. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ( Apco ) which holds oil and gas concessions in South America and trades on the NASDAQ Capital Market under the symbol APAGF.

In conjunction with our exploration and development activities, we engage in natural gas sales and marketing. Our sales and marketing activities to date include the sale of our natural gas, NGL and oil production, along with third party purchases and sales of natural gas, including sales to Williams Partners L.P. (NYSE: WPZ ) ( Williams Partners ) for use in its midstream business. We do not expect to continue to provide these services to Williams Partners on a long-term basis. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related price risk management activities. We also sell natural gas purchased from working interest owners in operated wells and other area third party producers. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. Revenues associated with the sale of our production are recorded in product revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes included in Part II, Item 8 in this Form 10-K. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in Risk Factors and Forward-Looking Statements.

**Separation from Williams**

On February 16, 2011, Williams announced that its board of directors had approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. As a result, WPX Energy, Inc. was formed to effect the separation. In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business, including its then wholly-owned subsidiaries WPX Energy Holdings, LLC (fomerly Williams Production Holdings, LLC) and WPX Energy Production, LLC (formerly Williams Production Company, LLC), as well as all ongoing operations of WPX Energy Marketing, LLC (formerly Williams Gas Marketing, Inc.). Additionally, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its 69 percent ownership interest in Apco in October 2011. We refer to the collective contributions described herein as the Contribution .

On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011, of WPX common stock to Williams stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date.

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**Basis of Presentation**

The consolidated financial statements included elsewhere in this Form 10-K, principally represented the Exploration & Production segment entity of Williams that were contributed in July 2011 and October 2011.

Up to the spin-off, our historical results included allocations of costs for corporate functions historically provided to us by Williams. See Note 4 of our Notes to Consolidated Financial Statements for more information.

Our management believes the assumptions and methodologies underlying the allocation of expenses from Williams are reasonable. However, such expenses may not be indicative of the actual level of expense that would have been or will be incurred by us as we operate as an independent, publicly traded company. We have entered into a transition services agreement with Williams that provides for continuation for some of these services in exchange for fees specified in these agreements.

During the first quarter 2011, we initiated a formal process to pursue the divestiture of our holdings in the Arkoma Basin and have recorded pretax impairment charges totalling $29 million based on an estimated fair value less cost to sell. Our daily Arkoma Basin production is approximately 9 MMcfd, or less than one percent of our total production. We have reported our Arkoma operations, including any impairment charges, as discontinued operations for all periods presented. Unless otherwise noted, the following discussion relates to our continuing operations.

**Overview**

The following table presents our production volumes and financial highlights for 2011, 2010 and 2009:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Production Sales Data: (1) | | | |
| Domestic natural gas (MMcf) | 413,520 | 392,776 | 417,537 |
| Domestic NGLs (MBbls) | 10,058 | 8,056 | 4,721 |
| Domestic oil (MBbls) | 2,676 | 857 | 803 |
| Domestic combined equivalent volumes (MMcfe) (2) | 489,926 | 446,252 | 450,679 |
| Domestic per day combined equivalent volumes (MMcfe/d) | 1,342 | 1,223 | 1,235 |
| Domestic combined equivalent volumes (MBoe) | 81,654 | 74,375 | 75,113 |
| International combined equivalent volumes (MMcfe) (2)(3) | 20,810 | 19,940 | 19,675 |
| Financial Data (millions): | | | |
| Total domestic revenues | $ 3,878 | $ 3,945 | $ 3,603 |
| Total international revenues | $ 110 | $ 89 | $ 78 |
| Consolidated operating income (loss) | $ (335) | $ (1,337) | $ 317 |
| Consolidated capital expenditures | $ 1,572 | $ 1,856 | $ 1,434 |

(1) Excludes production from our Arkoma Basin operations which are classified as discontinued operations and comprise less than one percent of our total production.
(2) Oil and NGLs were converted to MMcfe using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.
(3) Includes approximately 69 percent of Apco s production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

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Our 2011 results were impacted by low natural gas prices and due primarily to decreases in forward natural gas prices we have recognized in 2011 pre-tax impairment charges of $547 million associated with impairments of certain producing properties. Additionally, our 2010 operating results were negatively impacted by a $1 billion full impairment charge related to goodwill and $678 million of pre-tax charges associated with impairments of certain producing properties and costs of acquired unproved reserves. See Note 7 of the Notes to the Consolidated Financial Statements.

During late 2010 and 2011, we incurred approximately $11 million of exploratory drilling costs in connection with a Marcellus Shale well in Columbia County, Pennsylvania. Results were inconclusive and raised substantial doubt about the economic and operational viability of the well. As a result, the costs associated with this well were expensed as exploratory dry hole costs in third quarter 2011. Further, we assessed the impact of this well on our ability to recover the remaining lease acquisition costs associated with the acreage in Columbia County. During 2011, we recorded a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage that we do not plan to develop. The acreage in Columbia County represents approximately 21 percent of our total undeveloped acreage in the Marcellus Shale.

In connection with the separation from Williams, we entered into a $1.5 billion revolving credit agreement in June 2011. In November we issued $1.5 billion of senior notes consisting of $1.1 billion at 6.0% due 2022 and $400 million at 5.25% due 2017. Approximately $981 million of these proceeds were distributed to Williams. At December 31, 2011, we had $488 million of cash available for domestic operations and $38 million available for international operations.

**Outlook**

Although we are experiencing low natural gas prices, we believe we are well positioned to execute our business strategy of finding and developing reserves and producing natural gas, natural gas liquids and oil at costs that will generate an attractive rate of return on our consolidated incremental development investments. Our focus for 2012 is to continue to develop our natural gas portfolio to maintain current natural gas production levels, including the associated leasehold acreage, and grow our oil and natural gas liquids production. At current commodity pricing levels, we are focused on continuing to develop a more balanced reserve and production portfolio that will include a larger portion oil and NGLs reserves than we have historically maintained. With lower natural gas prices, we will continue to maintain our focus on drilling strategically to manage leasehold expirations and maintain our liquidity. A continued decrease in forward natural gas prices could signal a need to reduce capital spending in 2012 to maintain the liquidity and balance sheet we believe necessary to run our business.

We believe that our portfolio of reserves provides us an opportunity to continue to grow in our areas where we have oil production (Williston basin) and high concentrations of natural gas liquids (Piceance basin), which we believe will generate long-term sustainable value for shareholders. If gas prices were to increase, we believe we have the operational flexibility to respond by increasing our drilling in our natural gas areas. We expect 2012 capital expenditures to be approximately $1.2 billion.

We continue to operate with a focus on increasing shareholder value and investing in our businesses in a way that enhances our competitive position by:

- Continuing to invest in and grow our production and reserves;
- Retaining the flexibility to make adjustments to our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position and liquids-rich basins (primarily Piceance) with high concentrations of NGLs; and
- Continuing to maintain an active economic hedging program around our commodity price risks.

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Potential risks or obstacles that could impact the execution of our plan include:

- Lower than anticipated energy commodity prices;
- Lower than expected levels of cash flow from operations;
- Unavailability of capital;
- Higher capital costs of developing unconventional shale properties;
- Counterparty credit and performance risk;
- Decreased drilling success;
- General economic, financial markets or industry downturn;
- Changes in the political and regulatory environments; and
- Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation.

We continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we will begin entering into commodity derivative contracts that will continue to serve as economic hedges but will not be designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2011 that are included in accumulated other comprehensive income have been and will continue to be transferred to earnings during the same periods in which the forecasted hedged transactions are recognized.

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**Commodity Price Risk Management**

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. For 2012 we have the following contracts as of December 31, 2011 for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

| | | 2012 Natural Gas | | |
|---|---|---|---|---|
| | | Volume (BBtu/d) | Weighted Average Price ($/MMBtu) | |
| Location swaps | Rockies | 135 | $ | 4.76 |
| Location swaps | San Juan | 110 | $ | 4.94 |
| Location swaps | Mid-Continent | 88 | $ | 4.76 |
| Location swaps | Southern California | 33 | $ | 5.14 |
| Location swaps | Northeast | 143 | $ | 5.58 |
| Total all swaps | | 508 | $ | 5.06 |

| | 2012 Crude Oil | | |
|---|---|---|---|
| | Volume (Bbls/d) | Weighted Average Price ($/Bbl) Floor-Ceiling for Collars | |
| WTI crude oil fixed-price | 7,169 | $97.32 | |
| WTI crude oil costless collar | 2,000 | $85.00 | $106.30 |

We entered into natural gas liquid swaps during January 2012 consisting of 3,661 barrels per day at a weighted average price of $50.74 per whole barrel.

The following is a summary of our derivative contracts for daily domestic production shown at weighted average volumes and basin-level weighted average prices for the years ended December 31, 2011, 2010 and 2009:

| | | 2011 | | | | 2010 | | | | 2009 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Volume (BBtu/d) | Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars | | | Volume (BBtu/d) | Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars | | | Volume (BBtu/d) | Weighted Average Price ($/MMBtu) Floor-Ceiling for Collars | | |
| Collar agreements | Rockies | 45 | $ | 5.30 | $7.10 | 100 | $ | 6.53 | $8.94 | 150 | $ | 6.11 | $9.04 |
| Collar agreements | San Juan | 90 | $ | 5.27 | $7.06 | 233 | $ | 5.75 | $7.82 | 245 | $ | 6.58 | $9.62 |
| Collar agreements | Mid-Continent | 80 | $ | 5.10 | $7.00 | 105 | $ | 5.37 | $7.41 | 95 | $ | 7.08 | $9.73 |
| Collar agreements | Southern California | 30 | $ | 5.83 | $7.56 | 45 | $ | 4.80 | $6.43 | | | | |
| Collar agreements | Other | 30 | $ | 6.50 | $8.14 | 28 | $ | 5.63 | $6.87 | | | | |
| NYMEX and basis fixed-price swaps | | 372 | | | $5.22 | 120 | | | $4.40 | 106 | | | $3.67 |

| | 2011 Crude Oil | | |
|---|---|---|---|
| | Volume (Bbls/d) | Weighted Average Price ($/Bbl) | |
| WTI crude oil fixed-price | 3,315 | $ | 95.88 |

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to

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deliver on a firm basis 200,000 MMbtu/d of natural gas at monthly index pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation, which expires in 2014.

**Results of Operations**

Operations of our company are located in the United States and South America and are organized into Domestic and International reportable segments.

Domestic includes natural gas development, production and gas management activities located in the Rocky Mountain (primarily Colorado, New Mexico and Wyoming), Mid-Continent (Texas) and Appalachian regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Green River, Fort Worth and Appalachian Basins. During 2010, we acquired a company with a significant acreage position in the Williston Basin (Bakken Shale) in North Dakota, which is primarily comprised of crude oil reserves. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related hedges coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco, an oil and gas exploration and production company with concessions primarily in Argentina.

*2011 vs. 2010*

**Revenue Analysis**

| | Years ended December 31, | | | Percentage |
|---|---|---|---|---|
| | 2011 | 2010 | $ Change | Increase (Decrease) |
| | (Millions) | | | |
| Domestic revenues: | | | | |
| Natural gas sales | $ 1,779 | $ 1,797 | $ (18) | (1)% |
| Natural gas liquid sales | 404 | 282 | 122 | 43% |
| Oil and condensate sales | 229 | 57 | 172 | NM |
| Total product revenues including sales to Williams | 2,412 | 2,136 | 276 | 13% |
| Gas management, including sales to Williams | 1,428 | 1,742 | (314) | (18)% |
| Hedge ineffectiveness and mark to market gains and losses | 29 | 27 | 2 | 7% |
| Other | 9 | 40 | (31) | (78)% |
| Total domestic revenues | $ 3,878 | $ 3,945 | $ (67) | (2)% |
| Total international revenues | $ 110 | $ 89 | $ 21 | 24% |
| Total revenues | $ 3,988 | $ 4,034 | $ (46) | (1)% |

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

*Domestic Revenues*

Significant variances in comparative revenues reflect:

$18 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $4.30 compared to $4.57 in 2010 on production sales volumes of 413,520 MMcf and 392,776 MMcf , respectively. Without hedges, our natural gas price per Mcf in 2011 was $3.51 compared to $3.73 in 2010.

$122 million increase in natural gas liquids sales reflects a per barrel price of $40.17 in 2011 compared to $35.02 in 2010. Production sales volumes were 10,058 Mbbls in 2011 versus 8,056 Mbbls in 2010;

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$172 million increase in oil and condensate sales reflects a per barrel price of $85.38 (including the impact of hedges) in 2011 compared to $66.32 in 2010. Production sales volumes in 2011 were 2,676 Mbbls compared to 857 Mbbls in 2010. Production in 2011 reflected a full year of production associated with producing wells acquired in the Bakken acquisition completed in late 2010 as well as production from wells drilled during 2011.

A $314 million decrease in gas management revenues primarily due to a 7 percent decrease in average prices on physical natural gas sales and 12 percent lower natural gas sales volumes. We experienced a similar decrease of $298 million in related gas management costs and expenses; and

A $31 million decrease in other revenues primarily related to the absence of gathering revenues associated with the gathering and processing assets in Colorado s Piceance Basin that were sold to Williams Partners in the fourth quarter of 2010.

*International Revenues*

International revenues increased primarily due to increased average oil sales prices.

**Cost and operating expense and operating income (loss) analysis:**

| | Year ended December 31, 2011 | 2010 | $ Change | Percentage Increase (Decrease) |
|---|---|---|---|---|
| | (Millions) | | | |
| Domestic costs and expenses: | | | | |
| Lease and facility operating, including expenses with Williams | $ 268 | $ 267 | $ 1 | % |
| Gathering, processing and transportation, including expenses with Williams | 499 | 326 | 173 | 53% |
| Taxes other than income | 119 | 109 | 10 | 9% |
| Gas management, including charges for unutilized pipeline capacity | 1,473 | 1,771 | (298) | (17)% |
| Exploration | 131 | 67 | 64 | 96% |
| Depreciation, depletion and amortization | 927 | 858 | 69 | 8% |
| Impairment of producing properties and costs of acquired unproved reserves | 547 | 678 | (131) | (19)% |
| Goodwill impairment | | 1,003 | (1,003) | NM |
| General and administrative | 273 | 244 | 29 | 12% |
| Other net | (2) | (19) | 17 | (89)% |
| Total domestic costs and expenses | $ 4,235 | $ 5,304 | $ (1,069) | (20)% |
| International costs and expenses: | | | | |
| Lease and facility operating | $ 27 | $ 19 | $ 8 | 42% |
| Taxes other than income | 21 | 16 | 5 | 31% |
| Exploration | 3 | 6 | (3) | (50)% |
| Depreciation, depletion and amortization | 22 | 17 | 5 | 29% |
| General and administrative | 12 | 9 | 3 | 33% |
| Other net | 3 | | 3 | NM |
| Total international costs and expenses | $ 88 | $ 67 | $ 21 | 31% |
| Total costs and expenses | $ 4,323 | $ 5,371 | $ (1,048) | (20)% |
| Domestic operating income (loss) | $ (357) | $ (1,359) | $ 1,002 | (74)% |

| | | | | |
|---|---|---|---|---|
| International operating income | $ 22 | $ 22 | $ | % |

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

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*Domestic Costs*

Significant variances in comparative costs and expenses reflect:

Lease and facility operating expense reflects higher costs associated with higher production and increased workover, water management and maintenance activity, offset by the absence in 2011 of $28 million in expenses associated with the previously owned gathering and processing assets. Lease and facility operating expense in 2011 averaged $0.55 per Mcfe compared to $0.60 per Mcfe during 2010.

$173 million higher gathering, processing and transportation expenses primarily as a result of fees paid to Williams Partners in 2011 for gathering and processing associated with certain gathering and processing assets in the Piceance Basin that we sold to Williams Partners in the fourth quarter of 2010 and an increase in natural gas liquids volumes processed at Williams Partners Willow Creek plant. During 2011, gathering, processing and transportation expenses were $132 million higher due to fees paid to Williams Partners pursuant to the gathering and processing agreement associated with the assets sold Williams Partners in the fourth quarter of 2010. During 2010, our operating costs were $58 million associated with these assets (primarily reflected in lease and facility operating costs ($28 million) and depreciation, depletion and amortization ($17 million)). These costs are no longer directly incurred as operating costs (but rather as gathering, processing and transportation expenses) as we no longer own or operate these assets. Our gathering, processing and transportation charges averaged $1.02 per Mcfe in 2011 compared to an average of $0.73 per Mcfe in 2010.

$10 million higher taxes other than income primarily associated with the increase in oil and natural gas liquid sales volumes.

$298 million decrease in gas management expenses, primarily due to a 6 percent decrease in average prices on physical natural gas cost of sales and a 12 percent decrease in natural gas sales volumes. This activity represents natural gas purchased in connection with our gas purchase activities for Williams Partners and certain working interest owners share of production and to manage our transportation and storage activities. The sales associated with our marketing of this gas are included in gas management revenues. Also included in gas management expenses are $37 million and $48 million in 2011 and 2010, respectively, for unutilized pipeline capacity. Gas management expenses in 2011 and 2010 also include $10 million and $2 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage.

$64 million increase in exploration expense primarily due to the previously discussed dry hole and leasehold write-offs of $61 million in Columbia County, Pennsylvania coupled with increased leasehold amortization costs associated with leasehold acquisitions. Partially off-setting these increases is the absence of $15 million in dry hole charges recognized in 2010 associated with the Paradox basin.

$69 million higher depreciation, depletion and amortization expenses reflects higher production volumes partially offset by the absence of $17 million of depreciation expense related to the assets sold to Williams Partners in 2010. During 2011 our depreciation, depletion and amortization averaged $1.89 per Mcfe compared to an average $1.92 per Mcfe in 2010.

$547 million of property impairments in 2011 compared to $678 million in 2010.

The absence of the goodwill impairment from 2010 to 2011 as previously discussed;

$29 million higher general and administrative expenses primarily due to higher wages, salary and benefits costs primarily as a result of an increase in the number of employees. Our general and administrative expenses in 2011 averaged $0.56 per Mcfe in 2011 compared to an average of $0.55 per Mcfe in 2010. Additionally, general and administrative expenses in 2011 reflect approximately $5 million in costs associated with our initial public offering efforts and approximately $5 million in stock based compensation expense.

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Other-net in 2010 reflects a gain on sale of $12 million associated with a third-party sale of a portion of gathering and processing assets in the Piceance basin and a $7 million gain on exchange of undeveloped leasehold acreage with a third party.

*International costs*

International costs increased primarily due to increased production and lifting costs due to greater operating and maintenance activity and increased operating taxes associated with increased revenues.

**Consolidated results below operating income (loss)**

| | Years ended December 31, | | | Percentage Increase |
|---|---|---|---|---|
| | 2011 | 2010 | $ Change | (Decrease) |
| | (Millions) | | | |
| Consolidated operating loss | $ (335) | $ (1,337) | $ 1,002 | (75)% |
| Interest expense: | | | | |
| Interest expense Williams | (96) | (119) | 23 | (19)% |
| Interest expense other | (21) | (5) | (16) | NM |
| Total interest expense, including expenses with Williams | (117) | (124) | 7 | (6)% |
| Interest capitalized | 9 | 16 | (7) | (44)% |
| Investment income and other | 26 | 21 | 5 | 24% |
| Loss from continuing operations before income taxes | (417) | (1,424) | 1,007 | (71)% |
| Benefit for income taxes | (145) | (149) | 4 | (3)% |
| Loss from continuing operations | (272) | (1,275) | 1,003 | (79)% |
| Loss from discontinued operations | (20) | (8) | (12) | 150% |
| Net loss | (292) | (1,283) | 991 | (77)% |
| Less: Net income attributable to noncontrolling interests | 10 | 8 | 2 | 25% |
| Net loss attributable to WPX Energy | $ (302) | $ (1,291) | $ 989 | (77)% |

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Interest expense Williams in 2011 only reflects interest for six months as Williams cancelled and contributed to capital all amounts due under our unsecured notes payable with them on June 30, 2011. All cash receipts and cash expenditures transferred to or from Williams from July 1, 2011 to November 30, 2011 were considered owner s equity transactions between us and Williams and therefore no interest expense was recorded during this period. The interest expense-other in 2011 primarily reflects interest expense on our senior notes issued in November 2011.

Our investment income results primarily from equity earnings associated with our international and domestic equity investments.

Benefit for income taxes changed due to the lower pre-tax loss in 2011 compared to the pre-tax loss in 2010. See Note 11 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

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*2010 vs. 2009*

**Revenue Analysis:**

| | Year ended December 31, 2010 | 2009 | $ Change | Percentage Increase (Decrease) |
|---|---|---|---|---|
| | (Millions) | | | |
| Domestic revenues: | | | | |
| Natural gas sales | $ 1,797 | $ 1,916 | $ (119) | (6)% |
| Natural gas liquid sales | 282 | 136 | 146 | 107% |
| Oil and condensate sales | 57 | 38 | 19 | 50% |
| Total product revenues, including sales to Williams | 2,136 | 2,090 | 46 | 2% |
| Gas management, including sales to Williams | 1,742 | 1,456 | 286 | 20% |
| Hedge ineffectiveness and mark to market gains and losses | 27 | 18 | 9 | 50% |
| Other | 40 | 39 | 1 | 3% |
| Total domestic revenues | $ 3,945 | $ 3,603 | $ 342 | 9% |
| Total international revenues | $ 89 | $ 78 | $ 11 | 14% |
| Total revenues | $ 4,034 | $ 3,681 | $ 353 | 10% |

*Domestic Revenues*

Significant variances in comparative revenues reflect:

- $119 million decrease in natural gas sales reflects realized average prices per Mcf price of $4.57 (including hedges) in 2010 compared to $4.59 in 2009. Production volumes were 392,776 MMcf in 2010 compared to 417,537 MMcf in 2009. Excluding the impact of hedges, our per Mcf price was $3.73 in 2010 compared to $3.12 in 2009.

- $146 million increase in natural gas liquids reflects a per barrel price of $35.02 in 2010 compared to $28.80 in 2009. Volumes were 8,056 Mbbls in 2010 compared to 4,721 Mbbls in 2009. The volume increase reflects a full year of the Willow Creek plant which went into service in August 2009.

- $19 million increase in oil and condensate reflects a per barrel price of $66.32 in 2010 compared to $47.39 in 2009. Volumes were 857 Mbbls in 2010 compared to 803 Mbbls in 2009.

- A $286 million increase in gas management revenues primarily from a 21 percent increase in average prices on domestic physical natural gas sales associated with our transportation and storage contracts. There is a similar increase of $276 million in related gas management costs and expenses.

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*International Revenues*

International revenues increased primarily due to higher average oil sales prices coupled with increased sales volumes.

**Cost and operating expense and operating income (loss) analysis:**

| | Years ended December 31, 2010 | 2009 | $ Change | Percentage Increase (Decrease) |
|---|---|---|---|---|
| | (Millions) | | | |
| Domestic costs and expenses: | | | | |
| Lease and facility operating, including expenses with Williams | $ 267 | $ 247 | $ 20 | 8% |
| Gathering, processing and transportation, including expenses with Williams | 326 | 273 | 53 | 19% |
| Taxes other than income | 109 | 80 | 29 | 36% |
| Gas management (including charges for unutilized pipeline capacity) | 1,771 | 1,495 | 276 | 18% |
| Exploration | 67 | 53 | 14 | 26% |
| Depreciation, depletion and amortization | 858 | 870 | (12) | (1)% |
| Impairment of producing properties and costs of acquired unproved reserves | 678 | 15 | 663 | NM |
| Goodwill impairment | 1,003 | | 1,003 | NM |
| General and administrative, including Williams | 244 | 242 | 2 | 1% |
| Other net | (19) | 32 | (51) | NM |
| Total domestic costs and expenses | $ 5,304 | $ 3,307 | 1,997 | 60% |
| International costs and expenses: | | | | |
| Lease and facility operating | $ 19 | $ 16 | 3 | 19% |
| Taxes other than income | 16 | 13 | 3 | 23% |
| Exploration | 6 | 1 | 5 | NM |
| Depreciation, depletion and amortization | 17 | 17 | | % |
| General and administrative | 9 | 9 | | % |
| Other net | | 1 | (1) | NM |
| Total international costs and expenses | $ 67 | $ 57 | $ 10 | 18% |
| Total costs and expenses | $ 5,371 | $ 3,364 | $ 2,007 | 60% |
| Domestic operating income (loss) | $ (1,359) | $ 296 | $ (1,655) | NM |
| International operating income | $ 22 | $ 21 | $ 1 | 5% |

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

*Domestic Costs*

The increase in costs and expenses is primarily due to the following:

$20 million higher lease and facility operating expenses due to increased activity and generally higher industry costs. Our lease and facility operating expenses averaged $0.60 per Mcfe in 2010 compared to $0.55 per Mcfe in 2009.

$53 million higher gathering, processing and transportation expenses, primarily as a result of processing fees charged by Williams Partners at its Willow Creek plant for extracting NGLs from a

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portion of our Piceance Basin gas production. Our average gathering, processing and transportation charges were $0.73 per Mcfe in 2010 compared to $0.60 per Mcfe in 2009. The increase in the per unit amount is primarily a result of the Willow Creek plant going into service in August 2009 resulting in a partial year of processing. This processing provides us additional NGL recovery, the revenues for which are included in oil and gas sales in the Consolidated Statement of Operations;

$29 million higher taxes other than income, including severance and ad valorem, primarily due to higher average commodity prices (excluding the impact of hedges). Our taxes other than income averaged $0.24 per Mcfe in 2010 compared to $0.18 per Mcfe in 2009.

$276 million increase in gas management expenses, primarily due to an 18 percent increase in average prices on domestic physical natural gas cost of sales. This activity represents natural gas purchased in connection with our gas purchase activities for Williams Partners and certain working interest owners share of production, and to manage our transportation and storage activities. The sales associated with our marketing of this gas are included in gas management revenues. Also included in gas management expenses are $48 million in 2010 and $21 million in 2009 for unutilized pipeline capacity;

$14 million higher exploration expense primarily due to an increase in impairment, amortization and expiration of unproved leasehold costs;

$12 million lower depreciation, depletion and amortization expenses primarily due to lower natural gas domestic production volumes. Our depreciation, depletion and amortization expenses averaged $1.92 per Mcfe in 2010 compared to $1.93 per Mcfe in 2009;

$1,681 million impairments of property and goodwill in 2010 as previously discussed. In 2009, $15 million of impairments were recorded in the Barnett Shale;

Other-net in 2010 reflects a gain on sale of $12 million associated with a third-party sale of a portion of gathering and processing assets in the Piceance Basin and a $7 million gain on exchange of undeveloped leasehold acreage with a third party. Other net in 2009 includes $32 million of expenses in 2009 related to penalties from the early release of drilling rigs.

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*International Costs*

International costs and operating expense increases were primarily due to increased production and lifting costs associated with growth in operations. Additionally, exploratory expenses increased due to acquisition and processing of seismic information.

**Consolidated results below operating income (loss)**

| | Years ended December 31, 2010 | 2009 | $ Change | Percentage Increase (Decrease) |
|---|---|---|---|---|
| | (Millions) | | | |
| Consolidated operating income (loss) | $ (1,337) | $ 317 | $ (1,654) | NM |
| Interest expense: | | | | |
| Interest expense Williams | (119) | (92) | (27) | 29% |
| Interest expense other | (5) | (8) | 3 | (38)% |
| Total interest expense, including Williams | (124) | (100) | (24) | 24% |
| Interest capitalized | 16 | 18 | (2) | (11)% |
| Investment income and other | 21 | 8 | 13 | 163% |
| Income (loss) from continuing operations before income taxes | (1,424) | 243 | (1,667) | NM |
| Provision (benefit) for income taxes | (149) | 96 | (245) | NM |
| Income (loss) from continuing operations | (1,275) | 147 | (1,422) | NM |
| Loss from discontinued operations | (8) | (7) | (1) | 14% |
| Net income (loss) | (1,283) | 140 | (1,423) | NM |
| Less: Net income attributable to noncontrolling interests | 8 | 6 | 2 | 33% |
| Net income (loss) attributable to WPX Energy | $ (1,291) | $ 134 | $ (1,425) | NM |

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Interest expense increased primarily due to higher average amounts outstanding under the unsecured notes payable to Williams.

Investment income in 2009 reflects an $11 million full impairment of our 4 percent interest in a Venezuelan corporation that owns and operates oil and gas activities in Venezuela.

Provision (benefit) for income taxes changed due to the pre-tax loss in 2010 compared to pre-tax income in 2009. See Note 11 of the Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

**Management s Discussion and Analysis of Financial Condition and Liquidity**

***Overview***

In 2011, we continued to focus upon growth through continued disciplined investments in expanding our natural gas, oil and NGL portfolio while executing our separation from Williams.

Our historical liquidity needs have been managed through an internal cash management program with Williams. Daily cash activity from our domestic operation was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011 at which time the notes were cancelled by Williams. Any cash activity from

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July 1, 2011 until November 30, 2011 was treated as capital contribution. On December 1, 2011 we began to manage our own cash beginning with the $500 million retained after the issuance of the Notes. In consideration of our liquidity, we note the following:

- As of December 31, 2011, we maintained liquidity through cash, cash equivalents and available credit capacity under our credit facility.
- Our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support.
- Apco s liquidity requirements have historically been provided by its cash flows from operations.

***Outlook***

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures and tax and debt payments while maintaining a sufficient level of liquidity. We retained approximately $500 million of the net proceeds from the issuance of the Notes and have a $1.5 billion credit facility. These sources of liquidity along with our expected cash flows from operations should be sufficient to allow us to pursue our business strategy and goals for 2012 and 2013.

If energy commodity prices for 2012 and 2013 continue to trend lower, as they have done during early 2012, we believe the effect on our cash flows from operations would be partially mitigated by our hedging program. In addition, we note the following assumptions for 2012 and 2013:

- Our capital expenditures are estimated to be approximately $1.2 billion in 2012, and are generally considered to be largely discretionary; and
- Apco s liquidity requirements will continue to be provided from its cash flows from operations and available liquidity under its credit facility.

Potential risks associated with our planned levels of liquidity and the planned capital and investment

expenditures discussed above include:

- Sustained reductions in energy commodity prices from the range of current expectations;
- Lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;
- Higher than expected collateral obligations that may be required, including those required under new commercial agreements;
- Significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold; and
- Reduced access to our credit facility

Under the Credit Facility Agreement, we are required to maintain a ratio of PV to Consolidated Indebtedness of at least 1.50 to 1.00. PV is determined as of the end of each fiscal year and reflects the present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves. Further declines in natural gas prices during future years could reduce our PV and thus limit our available capacity under the agreement. However, we believe that we have full access to the $1.5 billion in 2012 based on year-end pricing. (See Note 10 to our to Consolidated Financial Statements)

We have executed three bilateral, uncommitted letter of credit agreements which we anticipate will be renewed annually. These agreements allow us to preserve our liquidity under our revolving credit agreement while providing support on our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility. At December 31, 2011 a total of $292 million in letters of credit have been issued with the potential for an additional $100 million in 2012 issuances.

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***Liquidity***

We plan to conservatively manage our balance sheet. Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2012. Our internal and external sources of consolidated liquidity include cash generated from operations, cash and cash equivalents on hand, and our credit facility. Additional sources of liquidity, if needed and if available, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales.

***Credit Ratings***

Our ability to borrow money will be impacted by several factors, including our credit ratings. Credit ratings agencies perform independent analysis when assigning credit ratings. A downgrade of our current rating could increase our future cost of borrowing and result in a requirement that we post additional collateral with third parties, thereby negatively affecting our available liquidity. The current ratings are as follows:

| | |
|---|---|
| Standard and Poor s (1) | |
| Corporate Credit Rating | BB+ |
| Senior Unsecured Debt Rating | BB+ |
| Outlook | Stable |
| Moody s Investors Service (2) | |
| Senior Unsecured Debt Rating | Ba1 |
| Outlook | Stable |

(1) A rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

(2) A rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1, 2, and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates the lower end of the category.

Additionally, under the Credit Facility, prior to our receipt of an investment grade rating with a stable outlook, we will be required to maintain a ratio of net present value of projected future cash flows from Proved Reserves to Consolidated Indebtedness (each as defined in the Credit Facility) of at least 1.50 to 1.00. The net present value is determined as of the end of each fiscal year and reflects the present value, discounted at nine percent, of projected future cash flows of domestic proved oil and gas reserves (with a limitation of no more than 35% that are not proved developed producing reserves), based on lender projected commodity price assumptions and after giving effect to hedge arrangements. It is possible that in the future our present value ratio calculation could result in limiting our full use of the $1.5 billion Credit Facility. Even if such a limitation were to occur, we believe our sources of liquidity will be sufficient for us to pursue our anticipated capital spending plans.

***Sources (Uses) of Cash***

The following table and discussion summarize our sources (uses) of cash for the years ended December 31, 2011, 2010 and 2009.

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| | | **(Millions)** | |
| Net cash provided (used) by: | | | |
| Operating activities | $ 1,206 | $ 1,056 | $ 1,181 |
| Investing activities | (1,556) | (2,337) | (1,435) |
| Financing activities | 839 | 1,284 | 256 |
| Increase in cash and cash equivalents | $ 489 | $ 3 | $ 2 |

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*Operating activities*

Our net cash provided by operating activities in 2011 increased from 2010 primarily due to net favorable changes in our operating assets and liabilities compared to 2010.

Our net cash provided by operating activities in 2010 decreased from 2009 primarily due to the payments made to reduce certain accrued liabilities affecting our operations.

*Investing activities*

Our net cash used by investing activities in 2011 decreased from 2010 primarily due to reduced capital expenditures and the absence of our acquisitions in 2010 for Marcellus Shale and Bakken Shale properties.

Our net cash used by investing activities in 2010 increased from 2009 primarily due to our capital expenditures related to the acquisition of Marcellus Shale properties and our entry into the Bakken Shale.

Significant items include:

*2011*

- Expenditures for drilling and completion were approximately $1.4 billion.

*2010*

- Expenditures for drilling and completion were approximately $950 million.
- Our acquisition in July 2010 of properties in the Marcellus Shale for $599 million.
- Our acquisition in December 2010 of oil and gas properties in the Bakken Shale for $949 million.
- The sale in November 2010 of certain gathering and processing assets in the Piceance Basin to Williams Partners for $702 million in cash ($244 million of which was in excess of our net book value and thus a financing and capital transaction with Williams) and approximately 1.8 million Williams Partners common units, which units were subsequently distributed to Williams.

*2009*

- Expenditures for drilling and completion were approximately $1.0 billion.
- A $253 million payment for the purchase of additional properties in the Piceance basin.

*Financing activities*

Our net cash from financing activities decreased in 2011 primarily due to distribution to Williams of approximately $981 million from our $1.5 billion in Note proceeds in November offset by lower borrowings from Williams in 2011 compared to 2010.

Our net cash provided by financing activities in 2010 increased from 2009 primarily due to higher borrowings from Williams to fund our capital expenditures, including those related to the acquisition of Marcellus Shale properties and our acquisition in the Bakken Shale.

***Off-Balance Sheet Financing Arrangements***

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at December 31, 2011 and December 31, 2010.

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***Contractual Obligations***

The table below summarizes the maturity dates of our contractual obligations at December 31, 2011, including obligations related to discontinued operations.

| | 2012 | 2013 - 2014 | 2015 - 2016 (Millions) | Thereafter | Total |
|---|---|---|---|---|---|
| Long-term debt, including current portion | | | | | |
| Principal | $ 1 | $ 2 | $ | $ 1,500 | $ 1,503 |
| Interest | 58 | 175 | 174 | 374 | 781 |
| Operating leases and associated service commitments | | | | | |
| Drilling rig commitments (1) | 153 | 219 | 38 | | 410 |
| Other | 14 | 18 | 18 | 35 | 85 |
| Transportation and storage commitments (2) | 215 | 388 | 316 | 489 | 1,408 |
| Natural gas purchase commitments (3) | 82 | 305 | 319 | 744 | 1,450 |
| Oil and gas activities (4) | 237 | 257 | 155 | 199 | 848 |
| Other | 22 | 19 | 11 | | 52 |
| Other long-term liabilities, including current portion: | | | | | |
| Physical and financial derivatives (5) | 457 | 615 | 671 | 2,831 | 4,574 |
| Total | $ 1,239 | $ 1,998 | $ 1,702 | $ 6,172 | $ 11,111 |

(1) Includes materials and services obligations associated with our drilling rig contracts.

(2) Excludes additional commitments totaling $601 million associated with projects for which the counterparty has not yet received satisfactory regulatory approvals.

(3) Purchase commitments are at market prices and the purchased natural gas can be sold at market prices. The obligations are based on market information as of December 31, 2011 and contracts are assumed to remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur. Certain parties have elected to convert their gas purchase agreements to firm gathering and processing agreements, which services will be provided by Williams Partners. WPX Energy s gas purchase obligations amounting to $1.4 billion will terminate at the effective date of the new agreements.

(4) Includes gathering, processing and other oil and gas related services commitments. Excluded are liabilities associated with asset retirement obligations, which total $302 million as of December 31, 2011. The ultimate settlement and timing can not be precisely determined in advance; however, we estimate that approximately 11% of this liability will be settled in the next five years.

(5) Includes $4.5 billion of physical natural gas derivatives related to purchases at market prices. The natural gas expected to be purchased under these contracts can be sold at market prices, largely offsetting this obligation. The obligations for physical and financial derivatives are based on market information as of December 31, 2011, and assume contracts remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur.

***Effects of Inflation***

Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy. Operating costs are influenced by both competition for specialized services and specific price changes in natural gas, oil, NGLs and other commodities. We tend to experience inflationary pressure on the cost of services and equipment as increasing oil and gas prices increase drilling activity in our areas of operation.

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**Environmental**

Our operations are subject to governmental laws and regulations relating to the protection of the environment, and increasingly strict laws, regulations and enforcement policies, as well as future additional environmental requirements, could materially increase our costs of operation, compliance and any remediation that may become necessary.

We are subject to the Clean Air Act ( CAA ). On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s proposed rule includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules also would establish specific new requirements regarding emissions from wells (including completions at new hydraulically fractured natural gas wells and re-completions of existing wells that are fractured or re-fractured), compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on the rules by April 3, 2012. If finalized as written, these rules could require modifications to our operations including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

On November 30, 2010, the EPA issued its final rule expanding the scope of the Greenhouse Gas ( GHG ) Mandatory Reporting Rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage, and distribution facilities. Reporting of GHG emissions will be required on an annual basis, with reporting beginning in March 2012 for emissions occurring in 2011. We are required to report our GHG emissions by March 2012 under this rule. Several of EPA s GHG rules are being challenged in court proceedings and depending on their outcome, such rules may be modified, rescinded or the EPA could develop new rules. Compliance with such rules could result in significant costs.

Our facilities and operations are also subject to the Clean Water Act ( CWA ) and implementing regulations of the EPA and the United States Army Corps of Engineers ( Corps ). On April 27, 2011, the EPA and the Corps released new draft guidance governing federal jurisdiction over wetlands and other isolated waters. They would, if adopted, significantly expand federal jurisdiction and permitting requirements under the CWA. Additionally, the draft guidance addresses the expanded scope of the CWA s key term waters of the United States to all CWA provisions, which prior guidance limited to Section 404 determinations. EPA and the Corps anticipate proposing a rule for final comment in 2012. We are unable at this time to estimate the cost that may be required to meet the proposed guidance or any related final rules.

There have been multiple legislative and regulatory initiatives relating to hydraulic fracturing that could also result in increased costs and additional operating restrictions or delays. Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to enact separate federal legislation or legislation at the state and local government levels to regulate hydraulic fracturing. Legislation has been introduced in the United States Congress called the Fracturing Responsibility and Awareness of Chemicals Act (the FRAC Act ) to amend the SDWA to eliminate an existing exemption for hydraulic fracturing activities from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as require disclosure of the chemical constituents of the fluids used in the fracturing process. The EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. In October, 2011, the EPA announced that it intends to propose regulations by 2014 under the CWA to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board in August 2011 also issued a report on hydraulic fracturing, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The United States Government Accountability Office is also examining the environmental impacts of produced water and the White House Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under the National Environmental Policy Act ( NEPA) for hydraulic fracturing.

Several states have also adopted or considered legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic fracturing, including states in which we operate (e.g., Wyoming, Pennsylvania, Texas, Colorado, North Dakota, New Mexico and Oklahoma). The United States Department of the Interior is also considering disclosure requirements or other mandates for hydraulic fracturing, which, if adopted, would affect our operations on federal lands. Compliance with such legislation or regulations could result in significant costs, including increased capital expenditures and operating cost, and could also cause delays, or eliminate certain drilling and injection activities, all of which could adversely impact our business.

**Critical Accounting Estimates**

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

In our management s opinion, the more significant reporting areas impacted by management s judgments and estimates are as follows:

***Impairments of Long-Lived Assets***

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset, and the current and future economic environment in which the asset is operated.

Due to the drop in natural gas forward prices during the fourth quarter of 2011, we assessed our natural gas producing properties and acquired unproved reserve costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The assessment performed identified certain properties with a carrying value in excess of those undiscounted cash flows and their calculated fair values. As a result, we recognized $547 million of impairment charges. See Notes 7 and 16 of Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For other producing assets reviewed, but for which impairment charges were not recorded, we estimate that approximately eight percent could be at risk for impairment if forward prices across all future periods decline by approximately 12 percent to 15 percent, on average, as compared to the forward prices at December 31, 2011. A substantial portion of the remaining carrying value of these other assets could be at risk for impairment if forward prices across all future periods decline by at least 24 percent, on average, as compared to the prices at December 31, 2011.

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***Accounting for Derivative Instruments and Hedging Activities***

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we will begin entering into commodity derivative contracts that will continue to serve as economic hedges but will not be designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2011 that are included in accumulated other comprehensive income have been and will continue to be transferred to earnings during the same periods in which the forecasted hedged transactions are recognized.

We review our energy contracts to determine whether they are, or contain, derivatives. Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short-term, with more than 99 percent of the value of our derivatives portfolio expiring in the next 24 months. We further assess the appropriate accounting method for any derivatives identified, which could include:

- qualifying for and electing cash flow hedge accounting, which recognizes changes in the fair value of the derivative in other comprehensive income (to the extent the hedge is effective) until the hedged item is recognized in earnings;

- qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or

- applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings.

If cash flow hedge accounting or accrual accounting is not applied, a derivative is subject to mark-to-market accounting. Determination of the accounting method involves significant judgments and assumptions, which are further described below.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in offsetting the cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives designated as cash flow hedges, we must periodically assess whether they continue to qualify for hedge accounting. We prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclassify amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting the cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the

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contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

Since our energy derivative contracts could be accounted for in three different ways, two of which are elective, our accounting method could be different from that used by another party for a similar transaction. Furthermore, the accounting method may influence the level of volatility in the financial statements associated with changes in the fair value of derivatives, as generally depicted below:

| | Consolidated Statement of Operations | | Consolidated Balance Sheet | |
|---|---|---|---|---|
| **Accounting Method** | **Drivers** | **Impact** | **Drivers** | **Impact** |
| Accrual Accounting | Realizations | Less Volatility | None | No Impact |
| Cash Flow Hedge Accounting | Realizations & Ineffectiveness | Less Volatility | Fair Value Changes | More Volatility |
| Mark-to-Market Accounting | Fair Value Changes | More Volatility | Fair Value Changes | More Volatility |

Our determination of the accounting method does not impact our cash flows related to derivatives.

Additional discussion of the accounting for energy contracts at fair value is included in Notes 1 and 15 of Notes to Consolidated Financial Statements.

***Successful Efforts Method of Accounting for Oil and Gas Exploration and Production Activities***

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates; and

- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, approximately 99 percent of our domestic reserves estimates are audited by independent experts. The data may change substantially over time as a result of numerous factors, including additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserves estimates could occur from time to time. Such changes could trigger an impairment of our oil and gas properties and have an impact on our depreciation, depletion and amortization expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual depreciation, depletion and amortization expense between approximately $81 million and $99 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserves categories.

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Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the forward price curve could result in an impairment of our oil and gas properties.

We record the cost of leasehold acquisitions as incurred. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. Changes in our assumptions regarding the estimates of the nonproductive portion of these leasehold acquisitions could result in impairment of these costs. Upon determination that specific acreage will not be developed, the costs associated with that acreage would be impaired. Our lease acquisition costs totaled $1.1 billion at December 31, 2011.

***Contingent Liabilities***

We record liabilities for estimated loss contingencies, including royalty litigation, environmental and other contingent matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 12 of Notes to Consolidated Financial Statements.

***Valuation of Deferred Tax Assets and Liabilities***

Through the effective date of the spin-off, our domestic operations were included in the consolidated and combined federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision has been calculated on a separate return basis for us and our consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected benefit to us could not be determined until the date of deconsolidation.

The determination of our effective state tax rate requires judgment as we did not exist as a stand-alone filer during these periods and the effective state tax rate can change periodically based on changes in our operations. Our effective state tax rate is based upon our current entity structure and the jurisdictions in which we operate. If the effective state tax rate were to be revised upward by one-tenth of one percent, this would result in an increase to our net deferred income tax liability of approximately $3 million.

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of book basis, from certain separate state losses generated in the current and prior years and, effective with the spin-off, from certain tax attributes allocated between us and Williams. We must periodically evaluate whether it is more likely than not we will realize these tax benefits and establish a valuation allowance for those that that do not meet the more likely than not threshold. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. When assessing the need for a valuation allowance, we consider forecasts of future company performance, the estimated impact of potential asset dispositions, and our ability and intent to execute tax planning strategies to utilize tax carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

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See Note 11 of Notes to Combined Financial Statements for additional information.

**Fair Value Measurements**

A limited amount of our energy derivative assets and liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At December 31, 2011, less than 1 percent of our energy derivative assets and liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2011, the credit reserve is less than $1 million on our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2011, 99 percent of the fair value of our derivatives portfolio expires in the next 12 months and approximately 100 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2011, consist of natural gas index transactions that are used to manage the physical requirements of our business. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices during the month of delivery. There are generally no active forward markets or quoted prices for natural gas index transactions.

For the years ended December 31, 2011 and 2010, we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. See Note 15 of Notes to Consolidated Financial Statements.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

***Interest Rate Risk***

Historically, our interest rate risk exposure was substantially mitigated through our cash management program and the effects of our intercompany note with Williams. Going forward, the Notes are fixed rate debt in order to mitigate the impact of fluctuations in interest rates and we expect that any borrowings under our Credit Facility will most likely be at a variable interest rate and could expose us to the risk of increasing interest rates. $400 million of the Notes mature in 2017 while the additional $1,100 million mature in 2022. Interest rates on each set are 5.25% and 6.00%, respectively. The aggregate fair value of the Notes is $1,521. See Note 10 of Notes to the Consolidated Financial Statements.

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***Commodity Price Risk***

We are exposed to the impact of fluctuations in the market price of natural gas, NGLs and crude oil, as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Note 17 of Notes to Consolidated Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

***Trading***

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net liability of $4 million at December 31, 2011 and a net asset of $2 million at December 31, 2010. The value at risk for contracts held for trading purposes was less than $1 million at December 31, 2011, December 31, 2010 and December 31, 2009.

***Nontrading***

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $14 million and $16 million at December 31, 2011 and December 31, 2010, respectively.

The value at risk for derivative contracts held for nontrading purposes was $15 million at December 31, 2011, and $24 million at December 31, 2010. During the year ended December 31, 2011, our value at risk for these contracts ranged from a high of $30 million to a low of $15 million. The decrease in value at risk from December 31, 2010 primarily reflects the realization of certain derivative positions and the market price impact, partially offset by new derivative contracts.

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Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $347 million and $266 million as of December 31, 2011 and December 31, 2010, respectively. The increase in value is primarily due to favorable changes due to falling prices on a net short natural gas positions partially offset with 2011 natural gas realizations. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders of WPX Energy, Inc.

We have audited the accompanying consolidated balance sheet of WPX Energy, Inc. as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audit also included the financial statement schedule listed in the Index at Item 15.(a). These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of WPX Energy, Inc. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

February 28, 2011

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**WPX Energy, Inc.**

**Consolidated Statement of Operations**

| | Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (Millions, except per share amounts) | | |
| Revenues: | | | |
| Product revenues, including sales to Williams: | | | |
| Natural gas sales | $ 1,795 | $ 1,812 | $ 1,929 |
| Natural gas liquid sales | 408 | 285 | 139 |
| Oil and condensate sales | 315 | 128 | 97 |
| Total product revenues, including sales to Williams | 2,518 | 2,225 | 2,165 |
| Gas management, including sales to Williams | 1,428 | 1,742 | 1,456 |
| Hedge ineffectiveness and mark to market gains and losses | 29 | 27 | 18 |
| Other | 13 | 40 | 42 |
| Total revenues | 3,988 | 4,034 | 3,681 |
| Costs and expenses: | | | |
| Lease and facility operating, including expenses with Williams | 295 | 286 | 263 |
| Gathering, processing and transportation, including expenses with Williams | 499 | 326 | 273 |
| Taxes other than income | 140 | 125 | 93 |
| Gas management, including charges for unutilized pipeline capacity | 1,473 | 1,771 | 1,495 |
| Exploration | 134 | 73 | 54 |
| Depreciation, depletion and amortization | 949 | 875 | 887 |
| Impairment of producing properties and costs of acquired unproved reserves | 547 | 678 | 15 |
| Goodwill impairment | | 1,003 | |
| General and administrative, including expenses with Williams | 285 | 253 | 251 |
| Other net | 1 | (19) | 33 |
| Total costs and expenses | 4,323 | 5,371 | 3,364 |
| Operating income (loss) | (335) | (1,337) | 317 |
| Interest expense, including expenses with Williams | (117) | (124) | (100) |
| Interest capitalized | 9 | 16 | 18 |
| Investment income and other | 26 | 21 | 8 |
| Income (loss) from continuing operations before income taxes | (417) | (1,424) | 243 |
| Provision (benefit) for income taxes | (145) | (149) | 96 |
| Income (loss) from continuing operations | (272) | (1,275) | 147 |
| Loss from discontinued operations | (20) | (8) | (7) |
| Net income (loss) | (292) | (1,283) | 140 |
| Less: Net income attributable to noncontrolling interests | 10 | 8 | 6 |
| Net income (loss) attributable to WPX Energy | $ (302) | $ (1,291) | $ 134 |
| Amounts attributable to WPX Energy, Inc.: | | | |
| Basic and diluted earnings (loss) per common share (see Note 6): | | | |
| Income (loss) from continuing operations | $ (1.43) | $ (6.51) | $ 0.71 |
| Loss from discontinued operations | (0.10) | (0.04) | (0.03) |

| | | | |
|---|---|---|---|
| Net income (loss) | $ (1.53) | $ (6.55) | $ 0.68 |
| Weighted-average shares (millions) | 197.1 | 197.1 | 197.1 |

See accompanying notes.

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**WPX Energy, Inc.**

**Consolidated Balance Sheet**

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 526 | $ 37 |
| Accounts receivable: | | |
| Trade, net of allowance for doubtful accounts of $13 and $16 as of December 31, 2011 and 2010, respectively | 447 | 362 |
| Williams | 62 | 60 |
| Derivative assets | 506 | 400 |
| Inventories | 74 | 77 |
| Other | 59 | 22 |
| Total current assets | 1,674 | 958 |
| Investments | 125 | 105 |
| Properties and equipment, net (successful efforts method of accounting) | 8,476 | 8,449 |
| Derivative assets | 10 | 173 |
| Other noncurrent assets | 147 | 161 |
| Total assets | $ 10,432 | $ 9,846 |
| **Liabilities and Equity** | | |
| Current liabilities: | | |
| Accounts payable: | | |
| Trade | 643 | 451 |
| Williams | 59 | 64 |
| Accrued and other current liabilities | 186 | 158 |
| Deferred income taxes | 116 | 87 |
| Notes payable to Williams | | 2,261 |
| Derivative liabilities | 152 | 146 |
| Total current liabilities | 1,156 | 3,167 |
| Deferred income taxes | 1,556 | 1,645 |
| Long-term debt | 1,503 | |
| Derivative liabilities | 7 | 143 |
| Asset retirement obligations | 296 | 282 |
| Other noncurrent liabilities | 155 | 125 |
| Contingent liabilities and commitments *(Note 12)* | | |
| Equity: | | |
| Stockholders equity: | | |
| Preferred stock (100 million shares authorized at $0.01 par value; no shares issued) | | |
| Common stock (2 billion shares authorized at $0.01 par value; 197 million shares issued at December 31, 2011) | 2 | |
| Additional paid-in-capital | 5,457 | |
| Williams net investment | | 4,244 |
| Accumulated other comprehensive income | 219 | 168 |
| Total stockholders equity | 5,678 | 4,412 |
| Noncontrolling interests in consolidated subsidiaries | 81 | 72 |

| | | |
|---|---|---|
| Total equity | 5,759 | 4,484 |
| Total liabilities and equity | $ 10,432 | $ 9,846 |

See accompanying notes.

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**WPX Energy, Inc.**

**Consolidated Statement of Changes in Equity**

| | WPX Energy, Inc., Stockholders | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common Stock | Capital in Excess of Par Value | Williams Net Investment | Accumulated Other Comprehensive Income (Loss)* | Total Stockholders Equity | Noncontrolling Interest** | Total |
| | (Dollars in millions) | | | | | | |
| Balance at December 31, 2008 | $ | $ | $ 5,136 | $ 298 | $ 5,434 | $ 59 | $ 5,493 |
| Comprehensive income: | | | | | | | |
| Net income | | | 134 | | 134 | 6 | 140 |
| Other comprehensive income: | | | | | | | |
| Change in fair value of cash flow hedges (net of $97 of income tax) | | | | 169 | 169 | | 169 |
| Net reclassifications into earnings of net cash flow hedge gains(net of $226 income tax provision) | | | | (395) | (395) | | (395) |
| Total other comprehensive income | | | | | | | (226) |
| Total comprehensive income | | | | | | | (86) |
| Net transfers with Williams | | | (16) | | (16) | | (16) |
| Dividends to noncontrolling interests | | | | | | (1) | (1) |
| Balance at December 31, 2009 | | | 5,254 | 72 | 5,326 | 64 | 5,390 |
| Comprehensive income: | | | | | | | |
| Net income | | | (1,291) | | (1,291) | 8 | (1,283) |
| Other comprehensive income: | | | | | | | |
| Change in fair value of net cash flow hedges (net of $184 of income tax) | | | | 321 | 321 | | 321 |
| Net reclassifications into earnings of cash flow hedge gain (net of $129 income tax provision) | | | | (225) | (225) | | (225) |
| Total other comprehensive loss | | | | | | | 96 |
| Total comprehensive loss | | | | | | | (1,187) |
| Cash proceeds in excess of historical book value related to assets sold to a Williams affiliate | | | 244 | | 244 | | 244 |
| Net transfers with Williams | | | 37 | | 37 | | 37 |
| Dividends to noncontrolling interests | | | | | | | |
| Balance at December 31, 2010 | | | 4,244 | 168 | 4,412 | 72 | 4,484 |
| Comprehensive income: | | | | | | | |
| Net loss | | | (302) | | (302) | 10 | (292) |
| Other comprehensive income: | | | | | | | |
| Change in fair value of net cash flow hedges (net of $151 of income tax) | | | | 262 | 262 | | 262 |
| Net reclassifications into earnings of cash flow hedge gains (net of $120 income tax provision) | | | | (211) | (211) | | (211) |
| Total other comprehensive income | | | | | | | 51 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Total comprehensive loss | | | | | | | (241) |
| Contribution of Notes Payable to Williams (Note 4) | | | 2,420 | | 2,420 | | 2,420 |
| Allocation of alternative minimum tax credit (see Note 11) | | | 98 | | 98 | | 98 |
| Net transfers with Williams | | | (25) | | (25) | | (25) |
| Distribution to Williams a portion of note proceeds | | | (981) | | (981) | | (981) |
| Recapitalization upon contribution by Williams | 2 | 5,452 | (5,454) | | | | |
| Dividends to noncontrolling interests | | | | | | (1) | (1) |
| Stock based compensation, net of tax benefit | | 5 | | | 5 | | 5 |
| Balance at December 31, 2011 | $ 2 | $ 5,457 | $ | $ 219 | $ 5,678 | $ 81 | $ 5,759 |

* Accumulated other comprehensive income (loss) is comprised primarily of unrealized gains relating to natural gas hedges totaling $221 million (net of $128 million for income taxes), $169 million (net of $97 million for income taxes) and $74 million (net of $42 million for income taxes) as of December 31, 2011, 2010 and 2009, respectively.

** Represents the 31 percent interest in Apco Oil and Gas International Inc. owned by others.

See accompanying notes.

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**WPX Energy, Inc.**

**Consolidated Statement of Cash Flows**

| | Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | | (Millions) | |
| **Operating Activities** | | | |
| Net income (loss) | $ (292) | $ (1,283) | $ 140 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, depletion and amortization | 951 | 882 | 894 |
| Deferred income tax provision (benefit) | (176) | (166) | 108 |
| Provision for impairment of goodwill and properties and equipment (including certain exploration expenses) | 694 | 1,734 | 38 |
| Provision for loss on cost-based investment | | | 11 |
| Amortization of stock-based awards | 5 | | |
| (Gain) loss on sales of other assets | (1) | (22) | 1 |
| Cash provided (used) by operating assets and liabilities: | | | |
| Accounts receivable and payable Williams | (10) | 21 | (72) |
| Accounts receivable trade | (90) | 7 | 103 |
| Other current assets | (11) | 19 | (17) |
| Inventories | 3 | (16) | 24 |
| Margin deposits and customer margin deposit payable | (18) | (1) | 4 |
| Accounts payable trade | 131 | (54) | (17) |
| Accrued and other current liabilities | 10 | (62) | (109) |
| Changes in current and noncurrent derivative assets and liabilities | 8 | (45) | 38 |
| Other, including changes in other noncurrent assets and liabilities | 2 | 42 | 35 |
| Net cash provided by operating activities | 1,206 | 1,056 | 1,181 |
| **Investing Activities** | | | |
| Capital expenditures* | (1,572) | (1,856) | (1,434) |
| Purchase of business | | (949) | |
| Proceeds from sales of assets | 15 | 493 | |
| Purchases of investments | (12) | (7) | (1) |
| Other | 13 | (18) | |
| Net cash used in investing activities | (1,556) | (2,337) | (1,435) |
| **Financing Activities** | | | |
| Proceeds from long term debt | 1,502 | | |
| Payments for debt issuance costs | (30) | | |
| Net increase in notes payable to Williams | 159 | 1,045 | 270 |
| Net changes in Williams net investment, including a $981 distribution in 2011 | (777) | 241 | (16) |
| Other | (15) | (2) | 2 |
| Net cash provided by financing activities | 839 | 1,284 | 256 |
| Net increase in cash and cash equivalents | 489 | 3 | 2 |
| Cash and cash equivalents at beginning of period | 37 | 34 | 32 |
| Cash and cash equivalents at end of period | $ 526 | $ 37 | $ 34 |
| | $ (1,641) | $ (1,891) | $ (1,291) |

| | | | |
|---|---|---|---|
| * Increase to properties and equipment | | | |
| Changes in related accounts payable | 69 | 35 | (143) |
| Capital expenditures | $ (1,572) | $ (1,856) | $ (1,434) |

See accompanying notes.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements**

### Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

#### Description of Business

Operations of our company are located in the United States and South America and are organized into Domestic and International reportable segments.

Domestic includes natural gas development, production and gas management activities located in the Rocky Mountain (primarily Colorado, New Mexico and Wyoming), Mid-Continent (Texas) and Appalachian regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Green River, Fort Worth and Appalachian Basins. During 2010, we acquired a company with a significant acreage position in the Williston Basin (Bakken Shale) in North Dakota, which is primarily comprised of crude oil. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage, and related derivatives coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco Oil and Gas International Inc. ( Apco , NASDAQ listed: APAGF), an oil and gas exploration and production company with concessions primarily in Argentina.

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as WPX or the Company , previously comprised substantially all of the exploration and production reportable segment of The Williams Companies, Inc. In these notes, WPX Energy, Inc. is at times referred to in the first person as WPX , we , us or our . The Williams Companies, Inc. and its affiliates, including Williams Partners L.P. (WPZ) are at times referred to collectively as Williams.

On February 16, 2011, Williams announced that its Board of Directors had approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. As a result, WPX Energy, Inc. was formed to effect the separation. In July 2011, Williams contributed to the Company its investment in certain subsidiaries related to its domestic exploration and production business, including its wholly-owned subsidiaries WPX Energy Holdings, LLC (formerly Williams Production Holdings, LLC) and WPX Energy Production, LLC (formerly Williams Production Company, LLC), as well as all ongoing operations of WPX Energy Marketing, LLC (formerly Williams Gas Marketing, Inc.). Additionally, Williams contributed and transferred to the Company its investment in certain subsidiaries related to its international exploration and production business, including its 69 percent ownership interest in Apco in October 2011. We refer to the collective contributions described herein as the Contribution .

On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a pro rata distribution on December 31, 2011 of WPX common stock to Williams stockholders of record as of the close of business on December 14, 2011, the spin-off record date. Each Williams stockholder received one share of WPX common stock for every three shares of Williams common stock held by such stockholder on the record date. See Note 4 for further discussion of agreements entered at the time of the spin-off, including a separation and distribution agreement, a transition services agreement, an employee matters agreement and a tax sharing agreement, among others.

#### Basis of Presentation

These financial statements are prepared on a consolidated basis. Prior to the Contribution, the financial statements were derived from the financial statements and accounting records of Williams using the historical results of operations and historical basis of the assets and liabilities of the Contribution to WPX.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Management believes the assumptions underlying the financial statements are reasonable. However, the financial statements included herein may not necessarily reflect the Company s results of operations, financial position and cash flows in the future or what its results of operations, financial position and cash flows would have been had the Company been a stand-alone company during the periods presented. Because a direct ownership relationship did not exist prior to the Contribution among the various entities that comprise the Company, Williams net investment in the Company, excluding notes payable to Williams, has been shown as Williams net investment within stockholder s equity in the consolidated financial statements. In connection with the Contribution, we have reflected the amounts previously presented as owner s net investment in excess of the par value of our common stock as additional paid-in capital. Transactions with Williams other operating businesses, which generally settle monthly, are shown as accounts receivable Williams or accounts payable Williams (see Note 4). Other transactions between the Company and Williams which are not part of the notes payable to Williams have been identified in the Consolidated Statement of Equity as net transfers with Williams (see Note 4).

*Discontinued operations*

During the first quarter 2011, we initiated a formal process to pursue the divestiture of our holdings in the Arkoma Basin. As these assets are currently held for sale, are expected to be eliminated from our ongoing operations, and we do not expect to have any significant continuing involvement, we have reported the results of operations and financial position of the Arkoma operations as discontinued operations.

Additionally, the accompanying consolidated financial statements and notes include the results of operations of Williams former power business most of which was disposed in 2007 as discontinued operations. See Note 12 for a discussion of contingencies related to this discontinued power business.

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations.

**Summary of Significant Accounting Policies**

*Principles of consolidation*

The consolidated financial statements include the accounts of our wholly and majority-owned subsidiaries and investments. Companies in which we own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the company, are accounted for under the equity method. All material intercompany transactions have been eliminated.

*Use of estimates*

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions which impact these financials include:

- Impairment assessments of long-lived assets and goodwill;
- Valuations of derivatives;

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

- Hedge accounting correlations and probability;
- Estimation of oil and natural gas reserves;
- Assessments of litigation-related contingencies.

These estimates are discussed further throughout these notes.

*Cash and cash equivalents*

Our cash and cash equivalents balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

*Restricted cash*

Restricted cash of our Domestic segment primarily consists of approximately $19 million in both 2011 and 2010 related to escrow accounts established as part of the settlement agreement with certain California utilities and is included in other noncurrent assets. Included in the separation and distribution agreement with Williams are indemnifications requiring us to pay to Williams any net asset (or receive any net liability) that result upon ultimate resolution of these matters. See Note 12. Additionally, our International segment holds approximately $8 million of restricted cash in 2011 associated with various letters of credit that is also classified in other noncurrent assets.

*Accounts receivable*

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. A portion of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

*Inventories*

All inventories are stated at the lower of cost or market. Our inventories consist of tubular goods and production equipment for future transfer to wells of $40 million in 2011 and $46 million in 2010. Additionally, we have natural gas in storage of $34 million in 2011 and $31 million in 2010 primarily related to our gas management activities. Inventory is recorded and relieved using the weighted average cost method except for production equipment which is on the specific identification method. We recognized lower of cost or market writedowns on natural gas in storage of $10 million in 2011, $2 million in 2010 and $7 million in 2009.

*Properties and equipment*

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to exploration expense. Other exploration costs, including geological and geophysical costs and lease rentals are charged to expense as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred whether productive or nonproductive.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of lease acquisition costs are included in exploration expense in the Consolidated Statement of Operations. A majority of the costs of acquired unproved reserves are associated with areas to which we or other producers have identified significant proved developed producing reserves. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of unproved reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. We refer to unproved lease acquisition costs and costs of acquired unproved reserves as unproved properties.

*Other capitalized costs*

Costs related to the construction or acquisition of field gathering, processing and certain other facilities are recorded at cost. Ordinary maintenance and repair costs are expensed as incurred.

*Depreciation, depletion and amortization*

Capitalized exploratory and developmental drilling costs, including lease and well equipment and intangible development costs are depreciated and amortized using the units-of-production method based on estimated proved developed oil and gas reserves on a field basis or concession basis for our international properties. International concession reserve estimates are limited to production quantities estimated through the life of the concession. Depletion of producing leasehold costs is based on the units-of-production method using estimated total proved oil and gas reserves on a field basis. In arriving at rates under the units-of-production methodology, the quantities of proved oil and gas reserves are established based on estimates made by our geologists and engineers.

Costs related to gathering, processing and certain other facilities are depreciated on the straight-line method over the estimated useful lives.

Gains or losses from the ordinary sale or retirement of properties and equipment are recorded in other net included in operating income (loss).

*Impairment of long-lived assets*

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate, in our management s judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management s estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the book value of the assets, then a subsequent analysis is performed using discounted cash flows.

Costs of acquired unproved reserves are assessed for impairment using estimated fair value determined through the use of future discounted cash flows on a field basis and considering market participants future drilling plans.

Judgments and assumptions are inherent in our management s estimate of undiscounted future cash flows and an asset s fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs and appropriate discount rates.

*Contingent liabilities*

Owing to the nature of our business, we are routinely subject to various lawsuits, claims and other proceedings. We recognize a liability in our consolidated financial statements when we determine that it is probable that a loss has been incurred and the amount can be reasonably estimated. If we determine that a loss is probable but lack information on which to reasonably estimate a loss, if any, or if we determine that a loss is only reasonably possible, we do not recognize a liability. We disclose the nature of loss contingencies that are potentially material but for which no liability has been recognized.

*Asset retirement obligations*

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation (ARO). These estimates include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market risk premium. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense in lease and facility operating expense included in costs and expenses.

*Goodwill*

As a result of significant declines in forward natural gas prices during 2010, we performed an interim impairment assessment of our goodwill related to our domestic production reporting unit. As a result of that assessment, we recorded an impairment of goodwill of approximately $1 billion and no longer have any goodwill recorded on the consolidated balance sheet related to our domestic operations (see Note 16).

Judgments and assumptions are inherent in our management s estimate of future cash flows used to determine the estimate of the reporting unit s fair value.

*Cash flows from revolving credit facilities*

Proceeds and payments related to any borrowings under our credit facilities are reflected in the financing activities of the Consolidated Statement of Cash Flows on a gross basis.

*Derivative instruments and hedging activities*

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheet in derivative assets and derivative liabilities as

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

| Derivative Treatment | Accounting Method |
|---|---|
| Normal purchases and normal sales exception | Accrual accounting |
| Designated in a qualifying hedging relationship | Hedge accounting |
| All other derivatives | Mark-to-market accounting |

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

For many of our existing commodity derivatives, we have also designated a hedging relationship. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in revenues or costs and operating expenses dependent upon the underlying hedge transaction.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in accumulated other comprehensive income (loss) (AOCI) and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative s change in fair value is recognized currently in revenues. Gains or losses deferred in AOCI associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in AOCI until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in AOCI is recognized in revenues at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;

The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;

Realized gains and losses on all derivatives that settle financially;

Realized gains and losses on derivatives held for trading purposes; and

Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

*Product revenues*

Revenues for sales of natural gas, natural gas liquids, and oil and condensate are recognized when the product is sold and delivered. Revenues from the production of natural gas in properties for which we have an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Our cumulative net natural gas imbalance position based on market prices as of December 31, 2011 and 2010 was insignificant. Additionally, natural gas revenues include hedge gains realized on production sold of $327 million in 2011, $333 million in 2010 and $615 million in 2009.

*Gas management revenues and expenses*

Revenues for sales related to gas management activities are recognized when the product is sold and physically delivered. Our gas management activities to date include purchases and subsequent sales to WPZ for fuel and shrink gas (see Note 4). Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges. The Company also sells natural gas purchased from working interest owners in operated wells and other area third party producers. The revenues and expenses related to these marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Charges for unutilized transportation capacity included in gas management expenses were $37 million in 2011, $48 million in 2010 and $21 million in 2009.

*Capitalization of interest*

We capitalize interest during construction on projects with construction periods of at least three months or a total estimated project cost in excess of $1 million. The interest rate used until June 30, 2011 was the rate charged to us by Williams through June 30, 2011, at which time our intercompany note with Williams was forgiven (see Note 4). We did not capitalize interest for the period from July 1, 2011 to mid November 2011. During November 2011, we began using the weighted average rate of our long-term notes payable which were issued in November 2011 (see Note 10).

*Income taxes*

Through the effective date of the spin-off, the Company s domestic operations were included in the consolidated and combined federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision has been calculated on a separate return basis for the Company and its consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected benefit to the Company could not be determined until the date of deconsolidation. This allocation methodology results in the recognition of deferred assets and liabilities for the differences between the financial statement carrying amounts and their respective tax basis, except to the extent of deferred taxes on income considered to be permanently reinvested in foreign jurisdictions. Deferred tax assets and liabilities are measured using enacted tax rates for the years in which those temporary differences are expected to be recovered or settled.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Effective with the spin-off, certain state and federal tax attributes (primarily alternative minimum tax credits) have been allocated between Williams and the Company. Although the final allocation of these tax attributes cannot be determined until the consolidated tax returns for tax year 2011 are complete, which is expected in the third quarter of 2012, an estimate of the tax attributes allocated to the Company has been recorded in the 2011 financial statements as part of the Contribution.

*Employee stock-based compensation*

Until spin-off, certain employees providing direct service to us participated in Williams common-stock-based awards plans. The plans provided for Williams common-stock-based awards to both employees and Williams non-management directors. The plans permitted the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards were granted for no consideration other than prior and future services or based on certain financial performance targets.

Until spin-off, Williams charged us for compensation expense related to stock-based compensation awards granted to our direct employees. Stock based compensation was also a component of allocated amounts charged to us by Williams for general and administrative personnel providing services on our behalf.

In preparation for the spin-off, Williams Compensation Committee determined that all outstanding Williams equity-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 (Pre-2006 Options) would convert into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options were converted into options covering both Williams and WPX common stock. The number of shares underlying each award and, with respect to options, the per share exercise price of each such award has been adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of such awards.

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of grant and can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options generally expire ten years after the grant.

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

*Foreign exchange*

Translation gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the United States dollar are included in the results of operations as incurred.

*Earnings (loss) per common share*

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. Diluted earnings (loss) per common share includes any dilutive effect of stock options and nonvested restricted stock units, unless otherwise noted. The impact of our stock issuance has been given effect to all periods presented. (see Note 6).

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Accounting Standards Issued But Not Yet Adopted**

In June 2011, the FASB issued Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220) Presentation of Comprehensive Income (ASU 2011-5). ASU 2011-5 requires presentation of net income and other comprehensive income either in a single continuous statement or in two separate, but consecutive, statements. ASU 2011-5 requires separate presentation in both net income and other comprehensive income of reclassification adjustments for items that are reclassified from other comprehensive income to net income. The new guidance does not change the items reported in other comprehensive income, nor affect how earnings per share is calculated and presented. We currently report net income in the Consolidated Statement of Operations and reports other comprehensive income in the Consolidated Statement of Equity. In December 2011, The FASB issued Accounting Standards Update No. 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12). ASU 2011-12 defers the effective date for only the presentation requirements related to reclassifications in ASU 2011-5. During this deferral period, ASU 2011-12 states that we should continue to report reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect before ASU 2011-05. All other requirements in ASU 2011-05 are not affected by ASU 2011-12, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. Both ASU s are effective beginning the first quarter of 2012, with retrospective application to prior periods. We will apply the new guidance for both ASUs beginning in 2012.

**Note 2. Restatement of Prior Periods**

We have determined that we did not appropriately provide for deferred federal income taxes on the outside basis differences of a foreign equity investee for the years ended December 31, 2010 and 2009. As a result, our provision (benefit) for income taxes was understated and our net income from continuing operations was overstated by $1 million and $2 million for the years ended December 31, 2010 and 2009, respectively, our deferred income tax liability was understated by $16 million at December 31, 2010 and our net equity was overstated by $16 million, $15 million and $13 million at December 31, 2010, 2009 and 2008, respectively. This restatement also adjusted downward our earnings per share attributable to WPX Energy, Inc. by $.01 in each of the years ended December 31, 2010 and 2009. Based on guidance set forth in Staff Accounting Bulletin No. 99, *Materiality* and in Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements,* ( SAB 108 ), we have determined that these amounts are immaterial to each of the periods affected and, therefore, we are not required to amend our previously filed financial statements. We have adjusted our previously reported results for the years ended December 31, 2010 and 2009 for these amounts.

**Note 3. Discontinued Operations**

**Summarized Results of Discontinued Operations**

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| | | (Millions) | |
| Revenues | $ 13 | $ 16 | $ 17 |
| Loss from discontinued operations before impairments, gain on sale and income taxes | $ (3) | $ (13) | $ (11) |
| Impairments | (29) | | |
| Benefit for income taxes | 12 | 5 | 4 |
| Loss from discontinued operations | $ (20) | $ (8) | $ (7) |

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Impairments in 2011 reflect write-downs to estimates of fair value less costs to sell the assets of our Arkoma Basin operations that were classified as held for sale as of December 31, 2011. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, utilized a probability-weighted discounted cash flow analysis that was based on internal cash flow models.

The assets of our discontinued operations are significantly less than one percent of our total assets as of December 31, 2011 and 2010 and are reported in other assets and other noncurrent assets, respectively on our Consolidated Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

**Note 4. Transactions with Williams**

During the fourth quarter of 2011, the Contribution and recapitalization of the Company was completed, whereby common stock held by Williams converted into approximately 197 million shares of WPX common stock. We also entered into agreements with Williams in connection with our separation from Williams. These agreements include:

- A Separation and Distribution agreement for, among other things, the separation from Williams and the distribution of WPX common stock, the distribution of a portion of the net proceeds from the debt financing as well as agreements between us and Williams, including those relating to indemnification;

- A tax sharing agreement, providing for, among other things, the allocation between Williams and WPX of federal, state, local and foreign tax liabilities for periods prior to the distribution and in some instances for periods after the distribution;

- An employee matters agreement discussed below; and

- A transition services agreement discussed below.

**Personnel and related services**

As previously discussed, our domestic operations were contributed to WPX Energy, Inc. on July 1, 2011. On June 30, 2011, certain entities that were contributed to us on July 1, 2011 withdrew from the Williams benefit plans and terminated their personnel services agreements with Williams payroll companies. Simultaneously, two new administrative service entities owned and controlled by Williams executed new personnel services agreements with the payroll companies and joined the Williams plans as participants. The effect of these transactions is that none of the companies contributed to WPX Energy in June 2011 had any employees. Through December 30, 2011, these service entities employed all personnel that provided services to the Company and remained owned and controlled by Williams.

In connection with the spin-off, we entered into an Employee Matters Agreement with Williams that set forth our agreements with Williams as to certain employment, compensation and benefits matters. The Employee Matters Agreement provides for the allocation and treatment of assets and liabilities arising out of employee compensation and benefit programs in which our employees participated prior to January 1, 2012. In connection with the spin-off, we provided benefit plans and arrangements in which our employees will participate going forward. Generally, other than with respect to equity compensation (discussed below), from and after January 1, 2012, we will sponsor and maintain employee compensation and benefit programs relating to all employees who transferred to us from Williams in connection with the spinoff through the contribution of two newly established service entities that employees of Williams were moved to prior to the spinoff. The Employee Matters Agreement provides that Williams will remain solely responsible for all liabilities under The Williams Companies Pension Plan, The Williams Companies Retirement Restoration Plan and The Williams Companies Investment Plus Plan. No assets and/or liabilities under any of those plans will be transferred to us or our benefit plans and our employees ceased active participation in those plans as of January 1, 2012. At December 31, 2011,

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

certain paid time off accruals approximating $13 million were transferred from Williams to us and are reflected in accrued liabilities. Additionally, while we have been charged for these costs, Williams remains responsible for any bonus amounts to be paid to our employees for the 2011 year which are currently estimated to be $19 million.

All outstanding Williams equity awards (other than stock options granted prior to January 1, 2006) held by our employees as of the spin-off were converted into WPX equity awards, issued pursuant to a plan that we established. See Note 14. In addition, outstanding Williams stock options that were granted prior to January 1, 2006 and held by our employees and Williams other employees as of the date of the spin-off were converted into options to acquire both WPX common stock and Williams common stock, in the same proportion as the number of shares of WPX common stock that each holder of Williams common stock received in the spin-off. The conversion maintained the same intrinsic value as the applicable Williams equity award as of the date of the conversion.

Until the spin-off, Williams charged us for the payroll and benefit costs associated with operations employees (referred to as direct employees) and carried the obligations for many employee-related benefits in its financial statements, including the liabilities related to employee retirement and medical plans. Our share of those costs was charged to us through affiliate billings and reflected in lease and facility operating and general and administrative within costs and expenses in the accompanying Consolidated Statement of Operations.

In addition, Williams charged us for certain employees of Williams who provide general and administrative services on our behalf (referred to as indirect employees). These charges were either directly identifiable or allocated to our operations. Direct charges included goods and services provided by Williams at our request. Allocated general corporate costs were based on our relative usage of the service or on a three-factor formula, which considers revenues; properties and equipment; and payroll. Our share of direct general and administrative expenses and our share of allocated general corporate expenses was reflected in general and administrative expense in the accompanying Consolidated Statement of Operations. In management s estimation, the allocation methodologies used are reasonable and result in a reasonable allocation to us of our costs of doing business incurred by Williams.

We have entered into a transition services agreement with Williams under which Williams will provide to us, upon our request and on an interim basis, various corporate support services subsequent to the spin-off. These services consist generally of the services that have been provided to us on an intercompany basis prior to the spin-off. These services relate to;

treasury services;

finance and accounting;

tax;

internal audit;

investor relations;

payroll and human resource administration;

information technology;

legal and government affairs;

insurance and claims administration;

records management;

real estate and facilities management;

sourcing and procurement; and

mail, print and other office services.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Pursuant to the transition services agreement, Williams will provide certain services for up to one year after the spin-off. Williams will provide the services and we will pay Williams costs, including Williams direct and indirect administrative and overhead charges allocated in accordance with Williams regular and consistent accounting practices. The transition services agreement may be terminated by either us or Williams upon 60 days notice after the spin-off. In addition, Williams may immediately terminate any of the services it provides under the transition services agreement if it determines that the provision of such services involves certain conflicts of interest between Williams and us or would cause Williams to violate applicable law.

**Other arrangements with Williams or its affiliates**

We also have operating activities with WPZ and another Williams subsidiary. Our revenues include revenues from the following types of transactions:

- Sales of natural gas liquids (NGLs) related to our production to WPZ at market prices at the time of sale and included within our oil and gas sales revenues; and

- Sales to WPZ and another Williams subsidiary of natural gas procured by WPX Energy Marketing for those companies fuel and shrink replacement at market prices at the time of sale and included in our gas management revenues.

Our costs and operating expenses include the following services provided by WPZ:

- Gathering, treating and processing services under several contracts for our production primarily in the San Juan and Piceance Basins; and

- Pipeline transportation for both our oil and gas sales and gas management activities which includes commitments totaling $401 million (see Note 12 for capacity commitments with affiliates).

In addition, through an agency agreement, we manage the jurisdictional merchant gas sales for Transcontinental Gas Pipe Line Company LLC (Transco), an indirect, wholly owned subsidiary of WPZ. We are authorized to make gas sales on Transco s behalf in order to manage its gas purchase obligations. We receive all margins associated with jurisdictional merchant gas sales business and, as Transco s agent, assume all market and credit risk associated with such sales. Gas sales and purchases related to our management of these jurisdictional merchant gas sales are included in gas management revenues and expenses, respectively, in the Consolidated Statement of Operations and the margins we realized related to these activities totaled less than $1 million in each of the years ended December 31, 2011, 2010 and 2009. We have signed an agreement with Williams under which these contracts will be assigned to them in the near term.

During fourth-quarter 2010, the Company sold certain gathering and processing assets in Colorado s Piceance Basin (the Piceance Sale) with a net book value of $458 million to WPZ, an entity under the common control of Williams, in exchange for $702 million in cash and 1.8 million WPZ limited partner units. As the Company and WPZ were under common control at that time, no gain was recognized on this transaction in the Consolidated Statement of Operations. Accordingly, the $244 million difference between the cash consideration received and the historical net book value of the assets has been reflected in the Consolidated Statement of Equity for the year ended December 31, 2010. Since the WPZ units received in this transaction by the Company were intended to be (and were, as described below) distributed through a dividend to Williams, these units (as well as the tax effects associated with these units of $42 million) have been presented net within equity and are included in net transfers with Williams in 2010. Further, as a result of the limitations on the Company s ability to sell these units and the subsequent dividend to Williams, no gains on the value of the common units during the holding period have been recognized in the Consolidated Statement of Operations. In conjunction with the Piceance Sale, we entered into long-term contracts with WPZ for gathering and processing of our natural gas production in the area. Due to the continuation of significant direct cash flows related to these assets, historical operating results of these assets have been presented in the Consolidated Statement of Operations as continuing operations for periods prior to the sale. In

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

March 2011, the 1.8 million WPZ units and related tax basis were distributed via dividend to Williams.

We have managed a transportation capacity contract for WPZ. To the extent the transportation is not fully utilized or does not recover full-rate demand expense, WPZ reimburses us for these transportation costs. These reimbursements to us totaled approximately $11 million, $10 million and $9 million for the years ended December 31, 2011, 2010 and 2009, respectively, and are included in gas management revenues. We have signed an agreement with WPZ under which these contracts will be assigned to them in the near term.

WPZ periodically entered into derivative contracts with us to hedge their forecasted NGL sales and natural gas purchases. We entered into offsetting derivative contracts with third parties at equivalent pricing and volumes. These contracts are included in derivative assets and liabilities on the Consolidated Balance Sheet at December 31, 2010. No contracts existed at December 31, 2011.

Prior to December 1, 2011 we participated in Williams centralized approach to cash management and the financing of its businesses. Daily cash activity from our domestic operations was transferred to or from Williams on a regular basis and was recorded as increases or decreases in the balance due under unsecured promissory notes we had in place with Williams through June 30, 2011, at which time the notes were cancelled by Williams. The amount due to Williams at the time of cancellation was $2.4 billion and is reflected as an increase in owner s net investment. Through fourth-quarter 2011, an additional $162 million was cancelled and reflected as an increase in owner s net investment. The notes reflected interest based on Williams weighted average cost of debt and such interest was added monthly to the note principle. The interest rate for the notes payable to Williams was 8.08%, 8.08% and 8.01% at June 30, 2011, December 31, 2010 and 2009, respectively.

Under Williams cash-management system, certain cash accounts reflected negative balances to the extent checks written had not been presented for payment. These negative amounts represented obligations and were reclassified to accounts payable-affiliate. Accounts payable-affiliate includes approximately $38 million of these negative balances at December 31, 2010. On December 1, 2011, we initiated our own cash management system as we began self-funding our operations. To the extent that certain cash accounts reflect negative balances, that obligation is reflected within our external accounts payable.

On August 25, 2011, we entered into a 10.5 year lease for our present headquarters office with Williams Headquarters Building Company, a direct subsidiary of Williams. We estimate the annual rent payable by us under the lease to be approximately $4 million per year.

Below is a summary of the transactions with Williams or its affiliates discussed above:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| | | (Millions) | |
| Product revenues sales of NGLs to WPZ | $ 258 | $ 277 | $ 116 |
| Gas management revenues sales of natural gas for fuel and shrink to WPZ and another Williams subsidiary | 586 | 509 | 431 |
| Lease and facility operating expenses from Williams-direct employee salary and benefit costs | 21 | 23 | 23 |
| Gathering, processing and transportation expense from services with WPZ: | | | |
| Gathering and processing | 298 | 163 | 72 |
| Transportation | 44 | 25 | 28 |
| General and administrative from Williams: | | | |
| Direct employee salary and benefit costs | 111 | 102 | 100 |
| Charges for general and administrative services | 62 | 58 | 60 |
| Allocated general corporate costs | 62 | 64 | 63 |
| Other | 16 | 12 | 13 |
| Interest expense on notes payable to Williams | 96 | 119 | 92 |

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

In addition, the current amount due to or from affiliates consists of normal course receivables and payables resulting from the sale of products to and cost of gathering services provided by WPZ. Below is a summary of these payables and receivables and other assets and liabilities with Williams and its affiliates:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Current: | | |
| Accounts receivable: | | |
| Due from WPZ and another Williams subsidiary | $ 62 | $ 60 |
| Other noncurrent assets Due from Williams | $ 11 | $ |
| Accounts payable: | | |
| Due to WPZ | $ 35 | $ 12 |
| Due to Williams for cash overdraft | | 38 |
| Due to Williams for accrued payroll and benefits | 10 | 14 |
| Due to Williams for administrative expenses | 14 | |
| | $ 59 | $ 64 |
| Noncurrent liability to Williams | $ 48 | $ |

**Note 5. Investment Income and Other**

**Investment income**

| | Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | | (Millions) | |
| Equity earnings | $ 24 | $ 20 | $ 18 |
| Impairment of cost-based investment | | | (11) |
| Other | 2 | 1 | 1 |
| Total investment income and other | $ 26 | $ 21 | $ 8 |

Impairment of cost-based investment in 2009 reflects an $11 million full impairment of our 4 percent interest in a Venezuelan corporation that owns and operates oil and gas activities in Venezuela.

**Investments**

**December 31,**

| | 2011 | 2010 |
|---|---|---|
| | (Millions) | |
| Petrolera Entre Lomas S.A. 40.8% | $ 90 | $ 82 |
| Other | 35 | 23 |
| | $ 125 | $ 105 |

Petrolera Entre Lomas S.A. operates several development concessions in South America. Other is comprised of investments in miscellaneous gas gathering interests in the United States.

Dividends and distributions received from companies accounted for by the equity method were $17 million in 2011, $19 million in 2010 and $9 million in 2009.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Note 6. Earnings (Loss) Per Common Share from Continuing Operations**

| | Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (Millions, except per-share amounts) | | |
| Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share | $ (282) | $ (1,283) | $ 141 |
| Basic weighted-average shares | 197.1 | 197.1 | 197.1 |
| Diluted weighted-average shares | 197.1 | 197.1 | 197.1 |
| Earnings (loss) per common share from continuing operations: | | | |
| Basic | $ (1.43) | $ (6.51) | $ 0.71 |
| Diluted | $ (1.43) | $ (6.51) | $ 0.71 |

On December 31, 2011, 197.1 million shares of our common stock were distributed to Williams shareholders in conjunction with our spin-off. For comparative purposes, and to provide a more meaningful calculation for weighted average shares, we have assumed this amount of common stock to be outstanding as of the beginning of each period presented in the calculation of basic weighted average shares.

For 2011 approximately 2.9 million weighted-average nonvested restricted stock units and 1.2 million weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive to our loss from continuing operations attributable to WPX Energy, Inc. For 2010 and 2009 these amounts are not given retrospective effect to the calculation.

**Note 7. Asset Sales, Impairments, Exploration Expenses and Other Accruals**

The following table presents a summary of significant gains or losses reflected in impairment of producing properties and costs of acquired unproved reserves, goodwill impairment and other net within costs and expenses. These significant adjustments are associated with our domestic operations.

| | Years Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | (Millions) | | |
| Goodwill impairment | $ | $ 1,003 | $ |
| Impairment of producing properties and costs of acquired unproved reserves * | 547 | 678 | 15 |
| Penalties from early release of drilling rigs included in other (income) expense net | | | 32 |
| (Gain) loss on sales of other assets | (1) | (22) | 1 |

* Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

As part of our assessment for impairments primarily resulting from declining forward natural gas prices during the fourth quarter 2011, we recorded a $276 million impairment of proved producing oil and gas properties in the Powder River basin and a $180 million impairment in Barnett Shale (see Note 16). Additionally, we recorded a $91 million impairment of our capitalized cost of acquired unproved reserves in the Powder River.

As a result of significant declines in forward natural gas prices during 2010, we performed an impairment assessment of our capitalized costs related to goodwill and domestic producing properties. As a result of these assessments, we recorded an impairment of goodwill, as noted above, and impairments of our capitalized costs of certain natural gas producing properties in the Barnett Shale of $503 million and capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million (see Note 16).

We recorded a $15 million impairment in 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth basin (see Note 16).

Our impairment analyses included an assessment of undiscounted (except for the costs of acquired unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities and natural gas reserve quantities.

In July 2010, we sold a portion of gathering and processing facilities in the Piceance basin to a third party for cash proceeds of $30 million resulting in a gain of $12 million. The remaining portion of the facilities was part of the Piceance Sale (see Note 4). Also in 2010, we exchanged undeveloped leasehold acreage in different areas with a third party resulting in a $7 million gain.

The following presents a summary of exploration expenses:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| | | (Millions) | |
| Geologic and geophysical costs | $ 18 | $ 22 | $ 33 |
| Dry hole costs | 13 | 17 | 11 |
| Unproved leasehold property impairment, amortization and expiration | 103 | 34 | 10 |
| Total exploration expense | $ 134 | $ 73 | $ 54 |

Dry hole costs in 2011 include an $11 million dry hole expense in connection with a Marcellus Shale well in Columbia County, Pennsylvania, while 2010 and 2009 reflect dry hole expense associated primarily with wells in the Paradox basin.

Unproved leasehold impairment, amortization and expiration in 2011 includes a $50 million write-off of leasehold costs associated with certain portions of our Columbia County acreage in Pennsylvania.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Note 8. Properties and Equipment**

Properties and equipment is carried at cost and consists of the following:

| | Estimated Useful Life (a) (Years) | December 31, 2011 | December 31, 2010 |
|---|---|---|---|
| | | (Millions) | |
| Proved properties | (b) | $ 9,985 | $ 9,822 |
| Unproved properties | (c) | 1,555 | 1,893 |
| Gathering, processing and other facilities | 15-25 | 181 | 119 |
| Construction in progress | (c) | 692 | 603 |
| Other | 3-25 | 99 | 127 |
| Total properties and equipment, at cost | | 12,512 | 12,564 |
| Accumulated depreciation, depletion and amortization | | (4,036) | (4,115) |
| Properties and equipment net | | $ 8,476 | $ 8,449 |

(a) Estimated useful lives are presented as of December 31, 2011.
(b) Proved properties are depreciated, depleted and amortized using the units-of-production method (see Note 1).
(c) Unproved properties and construction in progress are not yet subject to depreciation and depletion.

Unproved properties consist primarily of non-producing leasehold in the Williston Basin (Bakken Shale) and the Appalachian Basin (Marcellus Shale) and acquired unproved reserves in the Powder River and Piceance Basins.

On December 21, 2010, we closed the acquisition of 100 percent of the equity of Dakota-3 E&P Company LLC for $949 million, including closing adjustments. This company held approximately 85,800 net acres on the Fort Berthold Indian Reservation in the Williston Basin of North Dakota. Approximately 85% of the acreage was undeveloped. Approximately $400 million of the purchase price was recorded as proved properties, $542 million as unproved properties within properties and equipment and $5 million of prepaid drilling costs (no significant working capital was acquired). Revenues and earnings for the acquired company were nominal and thus insignificant to us for the years ended December 31, 2010 and 2009.

As discussed in Note 4 in 2010, the Company sold certain gathering and processing assets in Colorado s Piceance Basin with a net book value of $458 million to WPZ.

In May 2010, we entered into a purchase agreement consisting primarily of non-producing leasehold acreage in the Appalachian Basin and a 5 percent overriding royalty interest associated with the acreage position for $599 million.

Construction in progress includes $113 million in 2011 and $142 million in 2010 related to wells located in Powder River. In order to produce gas from the coal seams, an extended period of dewatering is required prior to natural gas production.

In 2009, we adopted Accounting Standards Update No. 2010-03, which aligned oil and gas reserve estimation and disclosure requirements to those in the Securities and Exchange Commission s final rule related thereto. Accordingly, our fourth quarter 2009 depreciation, depletion and amortization expense was approximately $17 million more than had it been computed under the prior requirements.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Asset Retirement Obligations**

Our asset retirement obligations relate to producing wells, gas gathering well connections and related facilities. At the end of the useful life of each respective asset, we are legally obligated to plug producing wells and remove any related surface equipment and to cap gathering well connections at the wellhead and remove any related facility surface equipment.

A rollforward of our asset retirement obligation for the years ended 2011 and 2010 is presented below.

| | 2011 | 2010 |
|---|---|---|
| | (Millions) | |
| Balance, January 1 | $ 285 | $ 242 |
| Liabilities incurred during the period | 23 | 43 |
| Liabilities settled during the period | (2) | (2) |
| Liabilities associated with assets sold | | (22) |
| Estimate revisions | (24) | 3 |
| Accretion expense * | 20 | 21 |
| Balance, December 31 | $ 302 | $ 285 |
| Amount reflected as current | $ 6 | $ 3 |

* Accretion expense is included in lease and facility operating expense on the Consolidated Statement of Operations.
Estimate revisions in 2011 are primarily associated with changes in anticipated well lives and plug and abandonment costs.

**Note 9. Accrued and other current liabilities**

**Accrued and other current liabilities**

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Taxes other than income taxes | $ 79 | $ 76 |
| Customer margin deposits | 7 | 25 |
| Accrued interest | 13 | 1 |
| Compensation and benefit related accruals | 13 | |
| Other, including other loss contingencies | 74 | 56 |
| | $ 186 | $ 158 |

Prior to the spin-off, employee compensation and benefit accruals were obligations of Williams with the expense related to compensation allocated to us through affiliate charges.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

## Note 10. Debt and Banking Arrangements

In connection with our separation from Williams, we issued $1.5 billion face value Senior Notes as follows:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| 5.250% Senior Notes due 2017 | $ 400 | $ |
| 6.000% Senior Notes due 2022 | 1,100 | |
| Other | 3 | |
| | $ 1,503 | $ |

***Senior Notes***

The Notes were issued under an indenture between us and The Bank of New York Mellon Trust Company, N.A., as trustee. The net proceeds from the offering of the Notes were approximately $1.481 billion after deducting the initial purchasers discounts and our offering expenses. We retained $500 million of the net proceeds from the issuance of the Notes and distributed the remainder of the net proceeds from the issuance of the Notes, approximately $981 million, to Williams in connection with the Contribution.

*Optional Redemption.* We have the option, prior to maturity, in the case of the 2017 notes, and prior to October 15, 2021 (which is the date that is three months prior to the maturity date of the 2022 notes), in the case of the 2022 notes, to redeem all or a portion of the Notes of the applicable series at any time at a redemption price equal to the greater of (i) 100% of their principal amount and (ii) the discounted present value of 100% of their principal amount and remaining scheduled interest payments, in either case plus accrued and unpaid interest to the redemption date. We also have the option at any time on or after October 15, 2021, to redeem the 2022 notes, in whole or in part, at a redemption price equal to 100% of their principal amount, plus accrued and unpaid interest thereon to the redemption date.

*Change of Control.* If we experience a change of control (as defined in the indenture governing the Notes) accompanied by a rating decline with respect to a series of Notes, we must offer to repurchase the Notes of such series at 101% of their principal amount, plus accrued and unpaid interest.

*Covenants.* The terms of the indenture restrict our ability and the ability of our subsidiaries to incur additional indebtedness secured by liens and to effect a consolidation, merger or sale of substantially all our assets. The indenture also requires us to file with the trustee and the SEC certain documents and reports within certain time limits set forth in the indenture. However, these limitations and requirements will be subject to a number of important qualifications and exceptions. The indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity.

*Events of Default.* Each of the following is an Event of Default under the indenture with respect to the Notes of any series:

(1) a default in the payment of interest on the Notes when due that continues for 30 days;

(2) a default in the payment of the principal of or any premium, if any, on the Notes when due at their stated maturity, upon redemption, or otherwise;

(3) failure by us to duly observe or perform any other of the covenants or agreements (other than those described in clause (1) or (2) above) in the indenture, which failure continues for a period of 60 days, or, in the case of the reporting covenant under the indenture, which failure continues for a period of 90 days, after

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

the date on which written notice of such failure has been given to us by the trustee; provided, however, that if such failure is not capable of cure within such 60-day or 90-day period, as the case may be, such 60-day or 90-day period, as the case may be, will be automatically extended by an additional 60 days so long as (i) such failure is subject to cure and (ii) we are using commercially reasonable efforts to cure such failure; and

(4) certain events of bankruptcy, insolvency or reorganization described in the indenture.

*Registration Rights Agreement.* As part of the new issuance, we entered into a registration rights agreement whereby we agree to offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and to use commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offer within 30 business days after such effective date. We are required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If we fail to fulfill these obligations, additional interest will accrue on the affected securities until we have successfully registered the securities.

***Credit Facility Agreement***

During 2011 we entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility Agreement ). Under the terms of the Credit Facility Agreement and subject to certain requirements, we may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. Borrowings may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. At December 31, 2011 there was no outstanding balance under the Credit Facility Agreement.

The Credit Facility Agreement became effective on November 1, 2011. Also, on November 1, 2011 we terminated our existing unsecured credit agreement which had served to reduce margin requirements and transaction fees related to hedging activities. All outstanding hedges under the terminated agreement were transferred to new agreements with various financial institutions that also participate in the new credit facility. We nor the participating financial institutions are required to provide collateral support related to hedging activities under the new agreements.

Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at the option of WPX Energy: (1) a fluctuating base rate equal to the Alternate Base Rate plus the Applicable Rate, or (2) a periodic fixed rate equal to LIBOR plus the Applicable Rate. The Alternate Base Rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. The Applicable Rate changes depending on which interest rate WPX selects and WPX s credit rating. Additionally, WPX Energy will be required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility Agreement.

Under the Credit Facility Agreement, prior to the occurrence of the Investment Grade Date (as defined below), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (each as defined in the Credit Facility Agreement) of at least 1.50 to 1.00. Net present value is determined as of the end of each fiscal year and reflects the present value, discounted at 9 percent, of projected future cash flows of domestic proved oil and gas reserves (such cash flows adjusted to reflect the impact of hedges, our lenders commodity price forecasts, and, if necessary, including only a portion of our reserves that are not proved developed producing reserves). Additionally, the ratio of debt to capitalization (defined as net worth plus debt) will not be permitted to be greater than 60%. Beginning December 31, 2011, each of the above ratios will be tested at the end of each fiscal quarter. We were in compliance with our debt covenant ratios as of December 31, 2011. Investment Grade Date means the first date on which our long-

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

term senior unsecured debt ratings are BBB- or better by S&P or Baa3 or better by Moody s (without negative outlook or negative watch), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody s.

The Credit Facility Agreement contains customary representations and warranties and affirmative, negative and financial covenants which were made only for the purposes of the Credit Facility Agreement and as of the specific date (or dates) set forth therein, and may be subject to certain limitations as agreed upon by the contracting parties. The covenants limit, among other things, the ability of our subsidiaries to incur indebtedness, make investments, loans or advances and enter into certain hedging agreements; our ability to merge or consolidate with any person or sell all or substantially all of our assets to any person, enter into certain affiliate transactions, make certain distributions during the continuation of an event of default and allow material changes in the nature of our business. In addition, the representations, warranties and covenants contained in the Credit Facility Agreement may be subject to standards of materiality applicable to the contracting parties that differ from those applicable to investors.

The Credit Facility Agreement includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to us occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of any loans outstanding under the Credit Facility Agreement at the time, in addition to the exercise of other rights and remedies available.

*Letters of Credit*

In addition to the Notes and Credit Facility Agreement, WPX has executed three bilateral, uncommitted letter of credit ( LC ) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility Agreement. At December 31, 2011 a total of $292 million in letters of credit have been issued.

*Other*

Apco executed a loan agreement with a financial institution for a $10 million bank line of credit. Borrowings under this facility are unsecured and bear interest at six-month LIBOR plus three percent per annum plus a one percent arrangement fee per borrowing and a commitment fee for the unused portion of the loan amount. The funds can be borrowed during a one-year period ending in March 2012, and principal amounts will be repaid in semi-annual installments from each borrowing date after a two and a half year grace period. This debt agreement contains covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, purchase or sell assets outside the ordinary course of business, and incur additional debt. As of December 31, 2011, we have borrowed $2 million under this banking agreement. Aggregate minimum maturities of this long-term debt are $1 million each for 2013 and 2014.

**Note 11. Income Taxes**

Through the effective date of the spin-off, the Company s domestic operations were included in the consolidated and combined federal and state income tax returns for Williams, except for certain separate state filings. The income tax provision has been calculated on a separate return basis for the Company and its consolidated subsidiaries, except for certain adjustments, such as alternative minimum tax calculated at the consolidated level by Williams, for which the ultimate expected impact to the Company could not be determined until the date of deconsolidation.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Effective with the spin-off, Williams and the Company entered into a tax sharing agreement which governs the respective rights, responsibilities and obligations of each company, for tax periods prior to the spin-off, with respect to the payment of taxes, filing of tax returns, reimbursements of taxes, control of audits and other tax proceedings, liability for taxes that may be triggered as a result of the spin-off and other matters regarding taxes.

The provision (benefit) for income taxes from continuing operations includes:

| | Years Ended December 31, 2011 | 2010 (Millions) | 2009 |
|---|---|---|---|
| Provision (benefit): | | | |
| Current: | | | |
| Federal | $ 5 | $ 7 | $ (17) |
| State | 4 | 1 | (1) |
| Foreign | 10 | 11 | 9 |
| | 19 | 19 | (9) |
| Deferred: | | | |
| Federal | (161) | (158) | 99 |
| State | (3) | (10) | 6 |
| | (164) | (168) | 105 |
| Total provision (benefit) | $ (145) | $ (149) | $ 96 |

Reconciliations from the provision (benefit) for income taxes from continuing operations at the federal statutory rate to the realized provision (benefit) for income taxes are as follows:

| | Years Ended December 31, 2011 | 2010 (Millions) | 2009 |
|---|---|---|---|
| Provision (benefit) at statutory rate | $ (146) | $ (498) | $ 85 |
| Increases (decreases) in taxes resulting from: | | | |
| State income taxes (net of federal benefit) | (8) | (6) | 3 |
| Effective state income tax rate change (net of federal benefit) | 9 | | |
| Foreign operations net | | 4 | 6 |
| Goodwill impairment | | 351 | |
| Other net | | | 2 |
| Provision (benefit) for income taxes | $ (145) | $ (149) | $ 96 |

Income (loss) from continuing operations before income taxes includes $40 million, $36 million and $21 million of foreign income in 2011, 2010 and 2009, respectively.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Significant components of deferred tax liabilities and deferred tax assets are as follows:

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Deferred tax liabilities: | | |
| Properties and equipment | $ 1,779 | $ 1,739 |
| Derivatives, net | 137 | 110 |
| Total deferred tax liabilities | 1,916 | 1,849 |
| Deferred tax assets: | | |
| Accrued liabilities and other | 146 | 117 |
| Alternative minimum tax credits (a) | 98 | |
| Loss carry-overs | 16 | 22 |
| Total deferred tax assets | 260 | 139 |
| Less: valuation allowance | 16 | 22 |
| Total net deferred tax assets | 244 | 117 |
| Net deferred tax liabilities | $ 1,672 | $ 1,732 |

(a) In connection with the spin-off from Williams effective December 31, 2011, alternative minimum tax credits were able to be estimated and allocated between Williams and the Company. This resulted in the allocation to the Company of $98 million with a corresponding increase to additional paid-in capital. Any subsequent adjustments of the alternative minimum tax credit allocation with Williams will be recorded in the provision for the period in which the change occurs.

As of December 31, 2011, the Company has approximately $290 million of state net operating loss carryovers of which approximately 75 percent expire after 2020.

The valuation allowance at December 31, 2011 and 2010 serves to reduce the recognized tax assets associated with state losses, net of federal benefit, to an amount that will more likely than not be realized by the Company. There have been no significant effects on the income tax provision associated with changes in the valuation allowance for the years ended December 31, 2011 and 2010.

Undistributed earnings of certain consolidated foreign subsidiaries excluding amounts related to foreign equity investments at December 31, 2011, totaled approximately $66 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in foreign operations.

The payments and receipts for domestic income taxes were made to or received from Williams in accordance with Williams intercompany tax allocation procedure. Cash payments for domestic income taxes (net of receipts) were $10 million, $5 million and ($13) million in 2011, 2010 and 2009, respectively. Additionally, payments made directly to international taxing authorities were $10 million, $8 million and $4 million in 2011, 2010 and 2009, respectively.

The Company s policy is to recognize related interest and penalties as a component of income tax expense. The amounts accrued for interest and penalties are insignificant.

Pursuant to our tax sharing agreement with Williams, we will remain responsible for the tax from audit adjustments related to our business for periods prior to the spin-off. During the first quarter of 2011, Williams

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

finalized settlements with the IRS for 1997 through 2008. The statute of limitations for most states expires one year after expiration of the IRS statute. Income tax returns for our foreign operations, primarily in Argentina, are open to audit for the 2004 to 2011 tax years.

As of December 31, 2011, the amount of unrecognized tax benefits is insignificant. During the next 12 months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter will result in a significant increase or decrease of our unrecognized tax benefit.

**Note 12. Contingent Liabilities and Commitments**

**Royalty litigation**

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County, Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for proceeds received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class for certification resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim is whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate litigating the second reserved claim in 2012. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint alleges failure to pay royalty on hydrocarbons including drip condensate, fraud and misstatement of value of gas and affiliated sales, breach of duty to market hydrocarbons, violation of the New Mexico Oil and Gas Proceeds Payment Act, bad faith breach of contract and unjust enrichment. Plaintiffs seek monetary damages and a declaratory judgment enjoining activities relating to production and payments and future reporting. This matter has been removed to the United States District Court for New Mexico. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Other producers have been in litigation with a federal regulatory agency and discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states though such guidelines are expected in the future. However, the timing of any such guidance is uncertain. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From January 2004 through December 2011, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $72 million.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that we have underpaid royalties due per the oil and gas leases with the State of New Mexico. In August 2011, the parties agreed to stay this matter pending the New Mexico Supreme Court s resolution of a similar matter involving a different producer. At this time, we do not have a sufficient basis to calculate an estimated range of exposure related to this claim.

**Environmental matters**

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, one hour nitrogen dioxide emission limits, and hydraulic fracturing and water standards. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

**Matters related to Williams former power business**

In connection with the Separation and Distribution Agreement, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us, and we are obligated to pay Williams any net proceeds realized from, the pending or threatened litigation described below relating to the 2000-2001 California energy crisis and the reporting of certain natural gas-related information to trade publications.

*California energy crisis*

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the FERC. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

*Reporting of natural gas-related information to trade publications*

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, seeking unspecified amounts of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. On January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

**Other Indemnifications**

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At December 31, 2011, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In connection with the separation from Williams, we have agreed to indemnify and hold Williams harmless from any losses resulting from the operation of our business or arising out of liabilities assumed by us. Similarly, Williams has agreed to indemnify and hold us harmless from any losses resulting from the operation of its business or arising out of liabilities assumed by it.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Summary**

As of December 31, 2011 and December 31, 2010, the Company had accrued approximately $23 million and $21 million, respectively, for loss contingencies associated with royalty litigation, reporting of natural gas information to trade publications and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

**Commitments**

As part of managing our commodity price risk, we utilize contracted pipeline capacity (including capacity on former affiliates systems, resulting in a total of $401 million for all years) to move our natural gas production and third party gas purchases to other locations in an attempt to obtain more favorable pricing differentials. Our commitments under these contracts as of December 31, 2011 are as follows:

| | (Millions) |
|---|---|
| 2012 | $ 215 |
| 2013 | 211 |
| 2014 | 177 |
| 2015 | 167 |
| 2016 | 149 |
| Thereafter | 489 |
| Total | $ 1,408 |

We also have certain commitments to an equity investee and others, primarily for natural gas gathering and treating services and well completion services, which total $780 million over approximately seven years.

We hold a long-term obligation to deliver on a firm basis 200,000 MMBtu per day of natural gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance Basin. This obligation expires in 2014.

In connection with a gathering agreement entered into by WPZ with a third party in December 2010, we concurrently agreed to buy up to 200,000 MMBtu per day of natural gas at Transco Station 515 (Marcellus Basin) at market prices from the same third party. Purchases under the 12-year contract are anticipated to begin in the first quarter of 2012. We expect to sell this natural gas in the open market and may utilize available transportation capacity to facilitate the sales.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Future minimum annual rentals under noncancelable operating leases as of December 31, 2011, are payable as follows:

| | (Millions) |
|---|---|
| 2012 | $ 67 |
| 2013 | 76 |
| 2014 | 67 |
| 2015 | 32 |
| 2016 | 9 |
| Thereafter | 36 |
| Total | $ 287 |

Total rent expense, excluding month-to-month rentals, was $16 million, $13 million and $22 million in 2011, 2010 and 2009, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting.

**Note 13. Employee Benefit Plans**

**Prior to spin-off**

Through the spin-off date, certain benefit costs associated with direct employees who support our operations are determined based on a specific employee basis and were charged to us by Williams as described below. These pension and post retirement benefit costs included amounts associated with vested participants who are no longer employees. As described in Note 4 Williams also charged us for the allocated cost of certain indirect employees of Williams who provided general and administrative services on our behalf. Williams included an allocation of the benefit costs associated with these Williams employees based upon a Williams determined benefit rate, not necessarily specific to the employees providing general and administrative services on our behalf. As a result, the information described below is limited to amounts associated with the direct employees that supported our operations.

For the periods presented, we were not the plan sponsor for these plans. Accordingly, our Consolidated Balance Sheet does not reflect any assets or liabilities related to these plans.

*Pension plans*

Williams is the sponsor of noncontributory defined benefit pension plans that provides pension benefits for its eligible employees. Pension expense charged to us by Williams for 2011, 2010 and 2009 totaled $8 million, $7 million and $7 million, respectively.

*Other postretirement benefits*

Williams is the sponsor of subsidized retiree medical and life insurance benefit plans (other postretirement benefits) that provides benefits to certain eligible participants, generally including employees hired on or before December 31, 1991, and other miscellaneous defined participant groups. Other postretirement benefit expense charged to us by Williams for 2011, 2010, and 2009 totaled less than $1 million for each period.

*Defined contribution plan*

Williams also is the sponsor of a defined contribution plan that provides benefits to certain eligible participants and has charged us compensation expense of $4 million, $5 million and $5 million in 2011, 2010 and 2009, respectively, for Williams matching contributions to this plan.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Subsequent to spin-off**

On January 1, 2012, several new plans became effective for us including a defined contribution plan. WPX matches dollar-for-dollar up to the first 6 percent of eligible pay per period. Employees also receive a non-matching annual employer contribution of equal to 8 percent of eligible pay if they are age 40 or older and 6 percent of eligible pay if they are under age 40.

**Note 14. Stock-Based Compensation**

Certain of our direct employees participated in The Williams Companies, Inc. 2007 Incentive Plan, which provides for Williams common-stock-based awards to both employees and Williams nonmanagement directors. The plan permits the granting of various types of awards including, but not limited to, stock options and restricted stock units. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets. Additionally, certain of our eligible direct employees participated in Williams Employee Stock Purchase Plan (ESPP). The ESPP enables eligible participants to purchase through payroll deductions a limited amount of Williams common stock at a discounted price.

Through the date of spin-off we were charged by Williams for stock-based compensation expense related to our direct employees. Williams also charges us for the allocated costs of certain indirect employees of Williams (including stock-based compensation) who provide general and administrative services on our behalf. However, information included in this note is limited to stock-based compensation associated with the direct employees (see Note 4 for total costs charged to us by Williams).

Williams Compensation Committee determined that all outstanding Williams stock-based compensation awards, whether vested or unvested, other than outstanding options issued prior to January 1, 2006 (the Pre-2006 Options), be converted into awards with respect to shares of common stock of the company that continues to employ the holder following the spin-off. The Pre-2006 Options (whether held by our employees or other Williams employees) converted into options for both Williams and WPX common stock following the spin-off, in the same ratio as is used in the distribution of WPX common stock to holders of Williams common stock. The number of shares underlying each such award (including the Pre-2006 Options) and, with respect to options (including the Pre-2006 Options), the per share exercise price of each award was adjusted to maintain, on a post-spin-off basis, the pre-spin-off intrinsic value of each award.

Total stock-based compensation expense included in general and administrative expense for the years ended December 31, 2011, 2010 and 2009 was $18 million, $14 million, and $13 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2011 was $24 million. This amount is comprised of $2 million related to stock options and $22 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

**WPX Energy, Inc. 2011 Incentive Plan**

Subsequent to the spin-off, we have an equity incentive plan and an employee stock purchase plan. The 2011 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units and other stock-based awards. The number of shares of common stock authorized for issuance pursuant to all awards granted under the 2011 Incentive Plan is 11,000,000 shares. The 2011 Incentive Plan will be administered by either the full Board of Directors or a committee as designated by the Board of Directors. Our employees, officers and non-employee directors are eligible to receive awards under the 2011 Incentive Plan.

The employee stock purchase plan allows domestic employees the option to purchase WPX common stock at a 15 percent discount through after-tax payroll deductions. The purchase price of the stock is the lower of

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

either the first or last day of the biannual offering periods, followed with the 15 percent discount. The maximum number of shares that shall be made available under the purchase plan is 1,000,000, subject to adjustment for stock splits and similar events.

**Employee stock-based awards**

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant.

Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

Restricted stock units are generally valued at fair value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

*Stock Options*

The following summary reflects stock option activity and related information for the year ended December 31, 2011.

| | WPX Plan | | | Direct employees participation in Williams Plan | | |
|---|---|---|---|---|---|---|
| **Stock Options** | **Options (Millions)** | **Weighted-Average Exercise Price** | **Aggregate Intrinsic Value (Millions)** | **Options (Millions)** | **Weighted-Average Exercise Price** | **Aggregate Intrinsic Value (Millions)** |
| Outstanding at December 31, 2010 | | $ | $ | 1.6 | $ 18.23 | $ 13 |
| Granted | | $ | | .2 | $ 29.73 | |
| Exercised | | $ | | (.4) | $ 13.52 | |
| Expired | | $ | | (.1) | $ 34.66 | |
| Conversion of direct employee options | 2.0 | $ 12.81 | | (1.3) | $ 21.08 | |
| Conversion of other options(1) | 2.2 | $ 10.16 | | | $ | |
| Outstanding at December 31, 2011 | 4.2 | $ 11.41 | $ 29 | | $ | |
| Exercisable at December 31, 2011 | 3.0 | $ 10.92 | $ 22 | | | |

(1) Includes approximately 962 thousand shares held by Williams employees at a weighted average price of $7.07 per share.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010, and 2009 was $7 million, $2 million, and $0.2 million, respectively.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2011.

| | WPX Plan | | | | | |
|---|---|---|---|---|---|---|
| | Stock Options Outstanding | | | Stock Options Exercisable | | |
| **Range of Exercise Prices** | **Options (Millions)** | **Weighted-Average Exercise Price** | **Weighted-Average Remaining Contractual Life (Years)** | **Options (Millions)** | **Weighted-Average Exercise Price** | **Weighted-Average Remaining Contractual Life (Years)** |
| $ 1.26 to $6.02 | 1.4 | $ 5.19 | 4.6 | 1.2 | $ 5.00 | 4.1 |
| $ 6.49 to $11.75 | 1.1 | $ 11.21 | 5.7 | 0.7 | $ 10.93 | 4.4 |
| $12.00 to $15.67 | 0.7 | $ 14.41 | 4.8 | 0.7 | $ 14.41 | 4.8 |
| $16.46 to $20.97 | 1.0 | $ 18.17 | 7.8 | 0.4 | $ 20.23 | 6.2 |
| Total | 4.2 | $ 11.41 | 5.7 | 3.0 | $ 10.92 | 4.6 |

The estimated fair value at date of conversion for WPX awards and the date of grant of options for Williams common stock granted in each respective year, using the Black-Scholes option pricing model, is as follows:

| | WPX Plan | Williams Plan | | |
|---|---|---|---|---|
| | 2011 | 2011 | 2010 | 2009 |
| Weighted-average or grant date fair value of options granted | $ | $ 7.71 | $ 7.02 | $ 5.60 |
| Weighted-average conversion date fair value options granted | $ 8.48 | | | |
| Weighted-average assumptions: | | | | |
| Dividend yield | % | 3.6% | 2.6% | 1.6% |
| Volatility | 45% | 34.6% | 39.0% | 60.8% |
| Risk-free interest rate | 0.377% | 2.84% | 3.0% | 2.3% |
| Expected life (years) | 2.8 | 6.5 | 6.5 | 6.5 |

For the WPX Plan the weighted average fair value is a component of the intrinsic value calculation at spin-off and is not necessarily indicative of the fair value of future WPX grants. The expected volatility yield is based on the historical volatility of comparable peer group stocks. The risk free rate interest rate is based on the U.S. Treasury Constant Maturity rates as of the modification date. The expected life of the options is based over the remaining option term.

For the Williams Plan, the expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of Williams stock and the implied volatility of Williams stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

*Nonvested Restricted Stock Units*

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2011.

| | WPX Plan | | Direct employees participation in Williams Plan | |
|---|---|---|---|---|
| **Restricted Stock Units** | **Shares (Millions)** | **Weighted-Average Fair Value*** | **Shares (Millions)** | **Weighted-Average Fair Value*** |
| Nonvested at December 31, 2010 | | $ | 1.8 | $ 16.93 |
| Granted | | $ | .5 | $ 27.74 |
| Forfeited | | $ | (.1) | $ 18.20 |
| Cancelled | | $ | (.1) | $ 35.47 |
| Vested | | $ | (.3) | $ 32.75 |
| Conversion of direct employee restricted units | 3.3 | $ 9.74 | (1.8) | $ 17.59 |
| Conversion of indirect employee restricted units | 1.3 | $ 9.54 | | |
| Nonvested at December 31, 2011 | 4.6 | $ 9.69 | | $ |

* Performance-based shares are primarily valued using a valuation pricing model. However, certain of these shares were valued using the end-of-period market price until certification that the performance objectives were completed or a value of zero once it was determined that it was unlikely that performance objectives would be met. All other shares are valued at the grant-date market price, less dividends projected to be paid over the vesting period.

*Other restricted stock unit information*

| | Williams Plan | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Weighted-average grant date fair value of Williams restricted stock units granted during the year, per share | $ 27.74 | $ 20.00 | $ 9.71 |
| Total fair value of restricted stock units vested during the year ($ s in millions) | $ 10 | $ 9 | $ 8 |

Performance-based shares granted represent 13 percent of nonvested restricted stock units outstanding at December 31, 2011. These grants may be earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

**Note 15. Stockholders Equity**

**Common Stock**

Each share of our common stock entitles its holder to one vote in the election of each director. No share of our common stock affords any cumulative voting rights. Holders of our common stock will be entitled to dividends in such amounts and at such times as our Board of Directors in its discretion may declare out of funds legally available for the payment of dividends. No dividends were declared or paid as of December 31, 2011. No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

**Preferred Stock**

Our amended and restated certificate of incorporation authorizes our Board of Directors to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action. Rights and privileges associated with shares of preferred stock are subject to authorization by our Board of Directors and may differ from those of any and all other series at any time outstanding.

**Note 16. Fair Value Measurements**

Fair value is the amount received from the sale of an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements primarily consist of financial instruments that are exchange traded.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 measurements primarily consist of over-the-counter (OTC) instruments such as forwards, swaps, and options. These options, which hedge future sales of production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model.

Level 3 Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

| | December 31, 2011 | | | | December 31, 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 (Millions) | Level 3 | Total | Level 1 | Level 2 (Millions) | Level 3 | Total |
| Energy derivative assets | $ 55 | $ 454 | $ 7 | $ 516 | $ 97 | $ 474 | $ 2 | $ 573 |
| Energy derivative liabilities | $ 41 | $ 112 | $ 6 | $ 159 | $ 78 | $ 210 | $ 1 | $ 289 |

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the net fair value of our derivatives portfolio expiring in the next 15 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2011, consist primarily of natural gas index transactions that are used to manage our physical requirements.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers between Level 1 and Level 2 occurred during the years ended December 31, 2011 or 2010. During the period ended March 31, 2011, certain NGL swaps that originated during the first quarter of 2011 were transferred from Level 3 to Level 2. Prior to March 31, 2011, these swaps were considered Level 3 due to a lack of observable third-party market quotes. Due to an increase in exchange-traded transactions and greater visibility from OTC trading, we transferred these instruments to Level 2. In 2009, certain options which hedge future sales of production were transferred from Level 3 to Level 2. These options were originally included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. Due to increased transparency, this input was considered observable, and we transferred these options to Level 2.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

**Level 3 Fair Value Measurements Using Significant Unobservable Inputs**

| | Years ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | Net Energy Derivatives | Net Energy Derivatives | Net Energy Derivatives |
| | | (Millions) | |
| Beginning balance | $ 1 | $ 1 | $ 506 |
| Realized and unrealized gains (losses): | | | |
| Included in income (loss) from continuing operations | 15 | 1 | 476 |
| Included in other comprehensive income (loss) | | | (329) |
| Purchases, issuances, and settlements | (12) | (1) | (479) |
| Transfers out of Level 3 | (3) | | (173) |
| Ending balance | $ 1 | $ 1 | $ 1 |
| Unrealized gains included in income (loss) from continuing operations relating to instruments still held at December 31 | $ 1 | $ | $ |

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statement of Operations.

For the year ending December 31, 2011, the entire $12 million reduction to level 3 fair value measurements are settlements.

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

| | Total losses for the years ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| | | (Millions) | |
| Impairments: | | | |
| Goodwill (see Note 7) | $ | $ 1,003(b) | $ |

| | | | |
|---|---|---|---|
| Producing properties and costs of acquired unproved reserves (see Note 7) | 547(a) | 678(c) | 15(d) |
| Cost-based investment (see Note 5) | | | 11(e) |
| | $ 547 | $ 1,681 | $ 26 |

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

(a) Due to significant declines in forward natural gas prices, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows including potential disposition proceeds. Significant judgments and assumptions in these assessments include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The annual assessment identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded the following impairment charges. Fair value measured for these properties at December 31, 2011, was estimated to be approximately $798 million.

$276 million of impairment charge related to natural gas-producing properties in Powder River. Significant assumptions in valuing these properties included proved reserves quantities of more than 352 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.81 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

$180 million of impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 235 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.24 per Mcfe for natural gas (adjusted for locational differences and contractual arrangements), natural gas liquids and oil, and an after-tax discount rate of 11 percent. Additionally, the weighted average price is net of deductions for gathering and processing.

$91 million of the impairment charge related to acquired unproved reserves in Powder River. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.

(b) Due to a significant decline in forward natural gas prices across all future production periods during 2010, we determined that we had a trigger event and thus performed an interim impairment assessment of the approximate $1 billion of goodwill related to our domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after- tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined that the

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

(c) As of September 30, 2010, we had a trigger event as a result of recent significant declines in forward natural gas prices and therefore, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments. Our assessment utilized estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $678 million impairment charge in the third-quarter 2010 as further described below. Fair value measured for these properties at September 30, 2010, was estimated to be approximately $320 million.

$503 million of impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent. Additionally, the weighted average price is net of deductions for gathering and processing.

$175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent.

(d) Fair value of costs acquired reserves in the Barnett Shale measured at December 31, 2009, was $22 million. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas prices (adjusted for locational differences) and an after-tax discount rate of 11 percent.

(e) Fair value measured at March 31, 2009 was zero. This value was based on an other-than-temporary decline in the value of our investment considering the deteriorating financial condition of a Venezuelan corporation in which we own a 4 percent interest.

**Note 17. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk**

We use the following methods and assumptions for financial instruments that require fair value disclosure.

*Cash and cash equivalents and restricted cash:* The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

*Other:* Includes margin deposits and customer margin deposits payable for which the amounts reported in the Consolidated Balance Sheet approximate fair value given the short-term status of the instruments.

*Long-term debt:* The fair value of our debt is determined on market rates and the prices of similar securities with similar terms and credit ratings.

*Energy derivatives:* Energy derivatives include futures, forwards, swaps and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 16 for a discussion of valuation of energy derivatives.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

Carrying amounts and fair values of our financial instruments were as follows:

| | December 31, | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| Asset (Liability) | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | | (Millions) | | |
| Cash and cash equivalents | $ 526 | $ 526 | $ 37 | $ 37 |
| Restricted cash (current and noncurrent) | 29 | 29 | 24 | 24 |
| Other | (7) | (7) | (25) | (25) |
| Long-term debt (1) | 1,502 | 1,523 | | |
| Net energy derivatives: | | | | |
| Energy commodity cash flow hedges | 347 | 347 | 266 | 266 |
| Other energy derivatives | 10 | 10 | 18 | 18 |

(1) Excludes capital leases.

For the year ended December 31, 2010 our note payable to Williams had a carrying amount of $2,261, which approximated fair value.

**Energy Commodity Derivatives**

*Risk Management Activities*

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and oil attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We produce, buy and sell natural gas and oil at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas market prices, we enter into natural gas and oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Those agreements and contracts designated as cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The following table sets forth the derivative volumes designated as hedges of production volumes as of December 31, 2011:

| Commodity | Period | Contract Type | Location | Notional Volume (BBtu) | Weighted Average Price ($/MMBtu) |
|---|---|---|---|---|---|
| Natural Gas | 2012 | Location Swaps | Rockies | 49,410 | $ 4.76 |
| Natural Gas | 2012 | Location Swaps | San Juan | 40,260 | $ 4.94 |
| Natural Gas | 2012 | Location Swaps | MidCon | 32,025 | $ 4.76 |
| Natural Gas | 2012 | Location Swaps | SoCal | 11,895 | $ 5.14 |
| Natural Gas | 2012 | Location Swaps | Northeast | 52,460 | $ 5.58 |
| Natural Gas | 2013 | Location Swaps | Northeast | 1,800 | $ 6.48 |

| Commodity | Period | Contract Type | Location | Notional Volume (MBbl) | Weighted Average Price ($/Bbl) |
|---|---|---|---|---|---|
| Crude Oil | 2012 | Business Day Avg Swaps | Midcon | 2,624 | $ 97.32 |

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Derivatives for transportation and storage contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties and affiliated entities. These legacy natural gas contracts include substantially offsetting positions and have had an insignificant net impact on earnings.

The following table depicts the notional amounts of the net long (short) positions which we did not designate as hedges of our production in our commodity derivatives portfolio as of December 31, 2011. Natural gas is presented in millions of British Thermal Units (MMBtu) and crude oil is presented in barrels. The volumes for options represent zero-cost collars and present one side of the short position. These 2012 options were executed to reduce exposure to a decrease in revenues from fluctuations in crude oil market prices. The floor and ceiling prices associated with these collars are $85 per barrel and $106.30 per barrel, respectively, and realize by December 2012. Despite being economic hedges, we did not designate these contracts in a hedge relationship for accounting purposes. All of the Central hub risk realizes by March 31, 2013 and 91% of the basis risk realizes by 2013. The net index position includes contracts for the future sale of physical natural gas related to our production. Offsetting these sales are contracts for the future production of physical natural gas related to WPZ s natural gas shrink requirements. These contracts result in minimal commodity price risk exposure and have a value of less than $1 million at December 31, 2011.

| Derivative Notional Volumes | Unit of Measure | Central Hub Risk (a) | Basis Risk (b) | Index Risk (c) | Option Risk (e) |
|---|---|---|---|---|---|
| **Not Designated as Hedging Instruments** | | | | | |
| Risk Management | MMBtu | (14,396,621) | (15,570,621) | (35,487,182) | |
| Other | MMBtu | (7,500) | (7,102,500) | | |
| Risk Management (d) | Barrels | (730,000) | | | (732,000) |

(a) includes physical and financial derivative transactions that settle against the Henry Hub price;
(b) includes physical and financial derivative transactions priced off the difference in value between the Central Hub and another specific delivery point;

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

(c) includes physical derivative transactions at an unknown future price, including purchases of 81,679,958 MMBtu primarily on behalf of WPZ and sales of 117,167,110 MMBtu.
(d) includes financial derivatives entered into to hedge our crude oil exposure that were not designated in a hedging relationship at December 31, 2011.
(e) includes all fixed price options or combination of options that set a floor and/or ceiling for the transaction price of a commodity.

*Fair values and gains (losses)*

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

| | December 31, | | | |
|---|---|---|---|---|
| | 2011 | | 2010 | |
| | Assets | Liabilities | Assets | Liabilities |
| | (Millions) | | | |
| Designated as hedging instruments | $ 360 | $ 13 | $ 288 | $ 22 |
| Not designated as hedging instruments: | | | | |
| Legacy natural gas contracts from former power business | 93 | 92 | 186 | 187 |
| All other | 63 | 54 | 99 | 80 |
| Total derivatives not designated as hedging instruments | 156 | 146 | 285 | 267 |
| Total derivatives | $ 516 | $ 159 | $ 573 | $ 289 |

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in accumulated other comprehensive income (AOCI) or revenues.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | Classification |
| | (Millions) | | |
| Net gain recognized in other comprehensive income (loss) (effective portion) | $ 413 | $ 505 | AOCI |
| Net gain reclassified from *accumulated other comprehensive income (loss)* into income (effective portion) (1) | $ 331 | $ 354 | Revenues |
| Gain recognized in income (ineffective portion) | $ | $ 9 | Revenues |

(1) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains associated with our production reflected in oil and gas sales.

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

| | Years Ended December 31, 2011 | Years Ended December 31, 2010 |
|---|---|---|
| | (Millions) | |
| Gas management revenues | $ 30 | $ 47 |
| Gas management expenses | | 28 |
| Net gain | $ 30 | $ 19 |

The cash flow impact of our derivative activities is presented in the Consolidated Statement of Cash Flows as changes in current and noncurrent derivative assets and liabilities.

*Credit-risk-related features*

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, we have an unsecured agreements with certain banks related to economic hedging activities. We are not required to provide collateral support for net derivative liability positions under these agreements.

As of December 31, 2011, we had collateral totaling $18 million posted to derivative counterparties to support the aggregate fair value of our net $37 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2010, we had collateral totaling $8 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $36 million, which included a reduction of less than $1 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $19 million and $29 million at December 31, 2011 and December 31, 2010, respectively.

*Cash flow hedges*

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of December 31, 2011, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at December 31, 2011, $219 million of net gains (net of income tax provision of $127 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of December 31, 2011. Due to the volatile nature of commodity prices and changes in the creditworthiness of

**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

**Concentration of Credit Risk**

*Cash equivalents*

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

*Accounts receivable*

The following table summarizes concentration of receivables (other than as relates to Williams), net of allowances, by product or service as of December 31:

| | 2011 | 2010 |
|---|---|---|
| | (Millions) | |
| Receivables by product or service: | | |
| Sale of natural gas and related products and services | $ 286 | $ 272 |
| Joint interest owners | 150 | 83 |
| Other | 11 | 7 |
| Total | $ 447 | $ 362 |

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains and Gulf Coast. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

*Derivative assets and liabilities*

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2011, 2010 and 2009, we did not incur any significant losses due to counterparty bankruptcy filings.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The gross credit exposure from our derivative contracts as of December 31, 2011, is summarized as follows.

| Counterparty Type | Investment Grade* | Total |
|---|---|---|
| | (Millions) | |
| Gas and electric utilities and integrated oil and gas companies | $ 2 | $ 2 |
| Energy marketers and traders | | 50 |
| Financial institutions | 410 | 464 |
| | $ 412 | 516 |
| Credit reserves | | |
| Gross credit exposure from derivatives | | $ 516 |

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2011, excluding collateral support discussed below, is summarized as follows.

| Counterparty Type | Investment Grade* | Total |
|---|---|---|
| | (Millions) | |
| Gas and electric utilities | $ 2 | $ 2 |
| Energy marketers and traders | | 4 |
| Financial institutions | 374 | 388 |
| | $ 376 | 394 |
| Credit reserves | | |
| Net credit exposure from derivatives | | $ 394 |

* We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade.

Our seven largest net counterparty positions represent approximately 97 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are counterparty positions hedging our production of energy commodities, representing 88 percent of our net credit exposure from derivatives. Under our new marginless hedging agreements with key banks, we nor the participating financial institutions are required to provide collateral support related to hedging activities.

At December 31, 2011, we hold collateral support, which may include cash or letters of credit, of $2 million related to our other derivative positions.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

*Revenues*

During 2011 and 2010, BP Energy Company, a domestic segment customer, accounted for 11% and 13% of our consolidated revenues, respectively. During 2009, there were no customers for which our sales exceeded 10 percent of our consolidated revenues. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

**Note 18. Segment Disclosures**

Our reporting segments are Domestic and International. (See Note 1.)

Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and International maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

***Performance Measurement***

We evaluate performance based upon segment revenues and segment operating income (loss). The accounting policies of the segments are the same as those described in Note 1. There are no intersegment sales between Domestic and International. Costs historically allocated from Williams were not allocated by us to our International segment.

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

The following tables reflect the reconciliation of segment revenues and segment operating income (loss) to revenues and operating income (loss) as reported in the Consolidated Statement of Operations. Long-lived assets are comprised of gross property, plant and equipment and long-term investments.

| For the year ended December 31, 2011 | Domestic | International (Millions) | Total |
|---|---|---|---|
| Total revenues | $ 3,878 | $ 110 | $ 3,988 |
| Costs and expenses: | | | |
| Lease and facility operating | $ 268 | $ 27 | $ 295 |
| Gathering, processing and transportation | 499 | | 499 |
| Taxes other than income | 119 | 21 | 140 |
| Gas management, including charges for unutilized pipeline capacity | 1,473 | | 1,473 |
| Exploration | 131 | 3 | 134 |
| Depreciation, depletion and amortization | 927 | 22 | 949 |
| Impairment of producing properties and costs of acquired unproved reserves | 547 | | 547 |
| General and administrative | 273 | 12 | 285 |
| Other net | (2) | 3 | 1 |
| Total costs and expenses | $ 4,235 | $ 88 | $ 4,323 |
| Operating income (loss) | $ (357) | $ 22 | $ (335) |
| Interest expense, including affiliate | (117) | | (117) |
| Interest capitalized | 9 | | 9 |
| Investment income and other | 6 | 20 | 26 |
| Income (loss) from continuing operation before income taxes | $ (459) | $ 42 | $ (417) |
| Other financial information: | | | |
| Net capital expenditures | $ 1,531 | $ 41 | $ 1,572 |
| Total assets | $ 10,144 | $ 288 | $ 10,432 |
| Long-lived assets | $ 12,284 | $ 354 | $ 12,638 |

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

| For the year ended December 31, 2010 | Domestic | International (Millions) | Total |
|---|---|---|---|
| Total revenues | $ 3,945 | $ 89 | $ 4,034 |
| Costs and expenses: | | | |
| Lease and facility operating | $ 267 | $ 19 | $ 286 |
| Gathering, processing and transportation | 326 | | 326 |
| Taxes other than income | 109 | 16 | 125 |
| Gas management, including charges for unutilized pipeline capacity | 1,771 | | 1,771 |
| Exploration | 67 | 6 | 73 |
| Depreciation, depletion and amortization | 858 | 17 | 875 |
| Impairment of producing properties and costs of acquired unproved reserves | 678 | | 678 |
| Goodwill impairment | 1,003 | | 1,003 |
| General and administrative | 244 | 9 | 253 |
| Other net | (19) | | (19) |
| Total costs and expenses | $ 5,304 | $ 67 | $ 5,371 |
| Operating income (loss) | $ (1,359) | $ 22 | $ (1,337) |
| Interest expense, including affiliate | (124) | | (124) |
| Interest capitalized | 16 | | 16 |
| Investment income and other | 4 | 17 | 21 |
| Income (loss) from continuing operation before income taxes | $ (1,463) | $ 39 | $ (1,424) |
| Other financial information: | | | |
| Net capital expenditures | $ 1,821 | $ 35 | $ 1,856 |
| Total assets | $ 9,590 | $ 256 | $ 9,846 |
| Long lived assets | $ 12,363 | $ 306 | $ 12,669 |

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**WPX Energy, Inc.**

**Notes to Consolidated Financial Statements (continued)**

| For the year ended December 31, 2009 | Domestic | International (Millions) | Total |
|---|---|---|---|
| Total revenues | $ 3,603 | $ 78 | $ 3,681 |
| Costs and expenses: | | | |
| Lease and facility operating | $ 247 | $ 16 | $ 263 |
| Gathering, processing and transportation | 273 | | 273 |
| Taxes other than income | 80 | 13 | 93 |
| Gas management, including charges for unutilized pipeline capacity | 1,495 | | 1,495 |
| Exploration | 53 | 1 | 54 |
| Depreciation, depletion and amortization | 870 | 17 | 887 |
| Impairment of producing properties and costs of acquired unproved reserves | 15 | | 15 |
| General and administrative | 242 | 9 | 251 |
| Other net | 32 | 1 | 33 |
| Total costs and expenses | $ 3,307 | $ 57 | $ 3,364 |
| Operating income | $ 296 | $ 21 | $ 317 |
| Interest expense, including affiliate | (100) | | (100) |
| Interest capitalized | 18 | | 18 |
| Investment income and other | 5 | 3 | 8 |
| Income from continuing operation before income taxes | $ 219 | $ 24 | $ 243 |
| Other financial information: | | | |
| Net capital expenditures | $ 1,409 | $ 25 | $ 1,434 |
| Total assets | $ 10,323 | $ 230 | $ 10,553 |
| Long lived assets | $ 11,014 | $ 270 | $ 11,284 |

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**WPX Energy, Inc.**

**QUARTERLY FINANCIAL DATA**

**(Unaudited)**

Summarized quarterly financial data are as follows:

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| | (Millions, except per-share amounts) | | | |
| **2011** | | | | |
| Revenues | $ 984 | $ 990 | $ 1,022 | $ 992 |
| Operating costs and expenses | 862 | 841 | 928 | 859 |
| Income (loss) from continuing operations | 7 | 28 | 19 | (326) |
| Net income (loss) | (1) | 28 | 16 | (335) |
| Amounts attributable to WPX Energy: | | | | |
| Net income (loss) | (3) | 25 | 14 | (338) |
| Basic and diluted earnings (loss) per common share: | | | | |
| Income (loss) from continuing operations | 0.02 | 0.13 | 0.09 | (1.67) |
| **2010** | | | | |
| Revenues | $ 1,164 | $ 904 | $ 1,006 | $ 960 |
| Operating costs and expenses | 960 | 775 | 882 | 839 |
| Income (loss) from continuing operations | 83 | 32 | (1,410) | 20 |
| Net income (loss) | 83 | 31 | (1,411) | 14 |
| Amounts attributable to WPX Energy: | | | | |
| Net income (loss) | 81 | 29 | (1,413) | 12 |
| Basic and diluted earnings (loss) per common share: | | | | |
| Income (loss) from continuing operations | 0.41 | 0.15 | (7.17) | 0.09 |

*The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to rounding.*

*Net loss* for fourth-quarter 2011 includes the following pre-tax items:

- $547 million of impairments of producing properties and costs of acquired unproved reserves (see Note 7) and $13 million of impairments related to the Arkoma discontinued operations (see Note 3).

*Net income* for third-quarter 2011 includes the following pre-tax items:

- $50 million write-off of leasehold costs associated with approximately 65 percent of our Columbia County, Pennsylvania acreage;

- $11 million of dry hole costs associated with an exploratory Marcellus Shale well in Columbia County;

*Net loss* for third-quarter 2010 includes the following pre-tax items:

- $1,003 million impairment of goodwill (see Note 7);

$678 million of impairments of certain producing properties and acquired unproved reserves (see Note 7);

$15 million of exploratory dry hole costs.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures**

**(Unaudited)**

We have significant oil and gas producing activities primarily in the Rocky Mountain, Northeast and Mid-continent areas of the United States. Additionally, we have international oil and gas producing activities, primarily in Argentina. The following information excludes our gas management activities.

With the exception of Capitalized Costs in 2011 and the Results of Operations for all years presented, the following information includes our Arkoma Basin operations which have been reported as discontinued operations in our consolidated financial statements. These operations represent less than one percent of our total domestic and international proved reserves for all periods presented.

**Capitalized Costs**

| | As of December 31, 2010 | | | |
|---|---|---|---|---|
| | Domestic | International | Consolidated Total | Entity s share of international equity method investee |
| Proved Properties | $ 9,854 | $ 213 | $ 10,067 | $ 220 |
| Unproved properties | 2,094 | 3 | 2,097 | |
| | 11,948 | 216 | 12,164 | 220 |
| Accumulated depreciation, depletion and amortization and valuation provisions | (3,867) | (109) | (3,976) | (129) |
| Net capitalized costs | $ 8,081 | $ 107 | $ 8,188 | $ 91 |

| | As of December 31, 2011 | | | |
|---|---|---|---|---|
| | Domestic | International | Consolidated Total | Entity s share of international equity method investee |
| Proved Properties | $ 10,116 | $ 259 | $ 10,375 | $ 254 |
| Unproved properties | 1,686 | 3 | 1,689 | |
| | 11,802 | 262 | 12,064 | 254 |
| Accumulated depreciation, depletion and amortization and valuation provisions | (3,696) | (133) | (3,829) | (154) |
| Net capitalized costs | $ 8,106 | $ 129 | $ 8,235 | $ 100 |

Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $349 million and $312 million, net, for 2011 and 2010, respectively.

Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs and successful exploratory wells.

Unproved properties consist primarily of unproved leasehold costs and costs for acquired unproven reserves.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

**Cost Incurred**

| | Domestic | International (Millions) | Entity s share of international equity method investee |
|---|---|---|---|
| **For the Year Ended December 31, 2009** | | | |
| Acquisition | $ 305 | $ 3 | $ |
| Exploration | 51 | 3 | 3 |
| Development | 878 | 19 | 21 |
| | $ 1,234 | $ 25 | $ 24 |
| **For the Year Ended December 31, 2010** | | | |
| Acquisition | $ 1,731 | $ | $ |
| Exploration | 22 | 13 | 3 |
| Development | 988 | 27 | 25 |
| | $ 2,741 | $ 40 | $ 28 |
| **For the Year Ended December 31, 2011** | | | |
| Acquisition | $ 45 | $ | $ |
| Exploration | 31 | 20 | 8 |
| Development | 1,461 | 24 | 26 |
| | $ 1,537 | $ 44 | $ 34 |

Costs incurred include capitalized and expensed items.

Acquisition costs are as follows: The 2011 costs are primarily for additional leasehold in the Appalachian basin. The 2010 costs are primarily for additional leasehold in the Williston and Appalachian basins and include approximately $422 million of proved property values. The 2009 costs are primarily for additional leasehold and reserve acquisitions in the Piceance basin, and include $85 million of proved property values.

Exploration costs include the costs incurred for geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions and retaining undeveloped leaseholds.

Development costs include costs incurred to gain access to and prepare well locations for drilling and to drill and equip wells in our development basins.

We have classified our step-out drilling and site preparation costs in the Powder River basin as development. While the immediate offsets are frequently in the dewatering stage, the development classification better reflects the low risk profile of the costs incurred.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

**Results of Operations**

| | Domestic | International (Millions) | Total |
|---|---|---|---|
| **For the Year Ended December 31, 2009** | | | |
| Revenues: | | | |
| Natural gas sales | $ 1,916 | $ 13 | $ 1,929 |
| Natural gas liquid sales | 136 | 3 | 139 |
| Oil and condensate sales | 38 | 59 | 97 |
| Other revenues | 39 | 3 | 42 |
| Total revenues | 2,129 | 78 | 2,207 |
| Costs: | | | |
| Lease and facility operating | 247 | 16 | 263 |
| Gathering, processing and transportation, including expenses with Williams | 273 | | 273 |
| Taxes other than income | 80 | 13 | 93 |
| Exploration | 53 | 1 | 54 |
| Depreciation, depletion and amortization | 869 | 17 | 886 |
| Impairment of costs of acquired unproved reserves | 15 | | 15 |
| General and administrative | 221 | 9 | 230 |
| Other (income) expense | 33 | 1 | 34 |
| Total costs | 1,791 | 57 | 1,848 |
| Results of operations | 338 | 21 | 359 |
| (Provision) benefit for income taxes | (123) | (8) | (131) |
| Exploration and production net income (loss) | $ 215 | $ 13 | $ 228 |

| | Domestic | International (Millions) | Total |
|---|---|---|---|
| **For the Year Ended December 31, 2010** | | | |
| Revenues: | | | |
| Natural gas sales | $ 1,797 | $ 15 | $ 1,812 |
| Natural gas liquid sales | 282 | 3 | 285 |
| Oil and condensate sales | 57 | 71 | 128 |
| Other revenues | 40 | | 40 |
| Total revenues | 2,176 | 89 | 2,265 |
| Costs: | | | |
| Lease and facility operating | 267 | 19 | 286 |
| Gathering, processing and transportation, including expenses with Williams | 326 | | 326 |

| | | | |
|---|---|---|---|
| Taxes other than income | 109 | 16 | 125 |
| Exploration | 67 | 6 | 73 |
| Depreciation, depletion and amortization | 858 | 17 | 875 |
| Impairment of certain natural gas properties in the Ft. Worth Basin | 503 | | 503 |
| Impairment of costs of acquired unproved reserves | 175 | | 175 |
| Goodwill impairment | 1,003 | | 1,003 |
| General and administrative | 225 | 9 | 234 |
| Other (income) expense | (19) | | (19) |
| Total costs | 3,514 | 67 | 3,581 |
| Results of operations | (1,338) | 22 | (1,316) |
| (Provision) benefit for income taxes | 123 | (8) | 115 |
| Exploration and production net income (loss) | $ (1,215) | $ 14 | $ (1,201) |

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

| | Domestic | International (Millions) | Total |
|---|---|---|---|
| **For the Year Ended December 31, 2011** | | | |
| Revenues: | | | |
| Natural gas sales | $ 1,779 | $ 16 | $ 1,795 |
| Natural gas liquid sales | 404 | 4 | 408 |
| Oil and condensate sales | 229 | 86 | 315 |
| Other revenues | 9 | 4 | 13 |
| Total revenues | 2,421 | 110 | 2,531 |
| Costs: | | | |
| Lease and facility operating | 268 | 27 | 295 |
| Gathering, processing and transportation, including expenses with Williams | 499 | | 499 |
| Taxes other than income | 119 | 21 | 140 |
| Exploration | 131 | 3 | 134 |
| Depreciation, depletion and amortization | 927 | 22 | 949 |
| Impairment of certain natural gas properties in the Ft. Worth Basin | 180 | | 180 |
| Impairment of certain natural gas properties in the Powder River Basin | 276 | | 276 |
| Impairment of costs of acquired unproved reserves | 91 | | 91 |
| General and administrative | 256 | 12 | 268 |
| Other (income) expense | (2) | 3 | 1 |
| Total costs | 2,745 | 88 | 2,833 |
| Results of operations | (324) | 22 | (302) |
| (Provision) benefit for income taxes | 119 | (8) | 111 |
| Exploration and production net income (loss) | $ (205) | $ 14 | $ (191) |

Amount for all years exclude the equity earnings from the international equity method investee. Equity earnings from this investee were $24 million, $16 million and $14 million in 2011, 2010 and 2009, respectively.

Natural gas revenues consist of natural gas production sold and includes the impact of hedges.

Other revenues consist of activities that are an indirect part of the producing activities. Other expenses in 2009 also include $32 million of expense related to penalties from the early release of drilling rigs.

Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes and the cost of retaining undeveloped leaseholds including lease amortization and impairments.

Depreciation, depletion and amortization includes depreciation of support equipment. Additionally, 2009 includes $17 million additional depreciation, depletion and amortization as a result of our recalculation of fourth quarter depreciation, depletion and amortization utilizing our year-end reserves. The lower reserves in fourth quarter 2009 were primarily a result of the application of new rules issued by the SEC.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

**Proved Reserves**

Our proved reserves were previously reported on a combined products basis, however, with the increase in the significance of our oil and natural gas liquids reserves estimates we have separated our disclosure into natural gas, oil and natural gas liquids. As a result, previously reported periods have been recast to reflect the current presentation. The International reserves are primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest. The Entity s share of international equity method investee represents Apco s 40.8% interest in reserves of Petrolera Entre Lomas S.A.

| | Natural Gas (Bcf) | | | |
|---|---|---|---|---|
| | Domestic | International | Entity s share of international equity method investee | Combined |
| **Proved reserves at December 31, 2008** | **4,321.3** | **74.4** | **23.9** | **4,419.6** |
| Revisions | (984.5) | 7.3 | 0.7 | (976.5) |
| Purchases | 156.4 | | | 156.4 |
| Extensions and discoveries | 998.4 | 11.8 | 15.3 | 1,025.5 |
| Production | (421.9) | (9.0) | (3.8) | (434.7) |
| **Proved reserves at December 31, 2009** | **4,069.7** | **84.5** | **36.1** | **4,190.3** |
| Revisions | (274.7) | (13.1) | 2.2 | (285.6) |
| Purchases | 37.3 | | | 37.3 |
| Extensions and discoveries | 478.7 | 11.9 | 13.7 | 504.3 |
| Production | (396.8) | (9.0) | (3.8) | (409.6) |
| **Proved reserves at December 31, 2010** | **3,914.2** | **74.3** | **48.2** | **4,036.7** |
| Revisions | (279.4) | 0.2 | (4.0) | (283.2) |
| Purchases | 8.0 | | | 8.0 |
| Divestitures | (12.8) | | | (12.8) |
| Extensions and discoveries | 769.7 | 9.6 | 11.5 | 790.8 |
| Production | (416.8) | (9.1) | (4.7) | (430.6) |
| **Proved reserves at December 31, 2011** | **3,982.9** | **75.0** | **51.0** | **4,108.9** |
| **Proved developed reserves at December 31, 2009** | 2,298.4 | 55.0 | 23.0 | 2,376.4 |
| **Proved developed reserves at December 31, 2010** | 2,368.5 | 43.4 | 27.9 | 2,439.8 |
| **Proved developed reserves at December 31, 2011** | 2,497.3 | 48.4 | 28.5 | 2,574.2 |

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

| | NGLs (MMBbls) | | | |
|---|---|---|---|---|
| | Domestic | International | Entity s share of international equity method investee | Combined |
| **Proved reserves at December 31, 2008** | | **0.7** | **0.8** | **1.5** |
| Revisions | 50.3 | 0.1 | | 50.4 |
| Purchases | 0.1 | | | 0.1 |
| Extensions and discoveries | 18.4 | 0.3 | 0.3 | 19.0 |
| Production | (4.7) | (0.1) | (0.1) | (4.9) |
| **Proved reserves at December 31, 2009** | **64.1** | **1.0** | **1.0** | **66.1** |
| Revisions | 30.7 | | | 30.7 |
| Purchases | 0.2 | | | 0.2 |
| Extensions and discoveries | 8.9 | 0.1 | 0.2 | 9.2 |
| Production | (8.1) | (0.1) | (0.1) | (8.3) |
| **Proved reserves at December 31, 2010** | **95.8** | **1.0** | **1.1** | **97.9** |
| Revisions | 23.0 | (0.1) | (0.1) | 22.8 |
| Purchases | 0.3 | | | 0.3 |
| Extensions and discoveries | 25.0 | | | 25.0 |
| Production | (10.1) | (0.1) | (0.1) | (10.3) |
| **Proved reserves at December 31, 2011** | **134.0** | **0.8** | **0.9** | **135.7** |
| **Proved developed reserves at December 31, 2009** | **31.6** | **0.8** | **0.7** | **33.1** |
| **Proved developed reserves at December 31, 2010** | **48.7** | **0.7** | **0.7** | **50.1** |
| **Proved developed reserves at December 31, 2011** | **72.1** | **0.6** | **0.6** | **73.3** |

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

| | Oil (MMBbls) | | | |
|---|---|---|---|---|
| | Domestic | International | Entity s share of international equity method investee | Combined |
| **Proved reserves at December 31, 2008** | **2.9** | **8.9** | **9.9** | **21.7** |
| Revisions | 0.8 | 0.7 | 0.8 | 2.3 |
| Purchases | 0.5 | | | 0.5 |
| Extensions and discoveries | 1.3 | 2.9 | 3.9 | 8.1 |
| Production | (0.8) | (1.4) | (1.6) | (3.8) |
| **Proved reserves at December 31, 2009** | **4.7** | **11.1** | **13.0** | **28.8** |
| Revisions | (0.9) | 0.1 | 0.3 | (0.5) |
| Purchases | 20.5 | | | 20.5 |
| Extensions and discoveries | 0.9 | 2.0 | 1.7 | 4.6 |
| Production | (0.9) | (1.3) | (1.6) | (3.8) |
| **Proved reserves at December 31, 2010** | **24.3** | **11.9** | **13.4** | **49.6** |
| Revisions | 1.2 | (0.7) | (0.9) | (0.4) |
| Extensions and discoveries | 24.3 | 1.5 | 1.3 | 27.1 |
| Production | (2.7) | (1.4) | (1.6) | (5.7) |
| **Proved reserves at December 31, 2011** | **47.1** | **11.3** | **12.2** | **70.6** |
| **Proved developed reserves at December 31, 2009** | **1.9** | **7.0** | **7.8** | **16.7** |
| **Proved developed reserves at December 31, 2010** | **4.0** | **7.1** | **8.1** | **19.2** |
| **Proved developed reserves at December 31, 2011** | **13.6** | **6.8** | **7.6** | **28.0** |

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

| | All products (Bcfe) (1) | | | |
|---|---|---|---|---|
| | Domestic | International | Entity s share of international equity method investee | Combined |
| **Proved reserves at December 31, 2008** | **4,338.6** | **132.2** | **88.1** | **4,558.9** |
| Revisions | (678.2) | 11.9 | 5.5 | (660.8) |
| Purchases | 159.8 | | | 159.8 |
| Extensions and discoveries | 1,116.6 | 31.0 | 40.5 | 1,188.1 |
| Production | (455.0) | (18.2) | (14.0) | (487.2) |
| **Proved reserves at December 31, 2009** | **4,481.8** | **156.9** | **120.1** | **4,758.8** |
| Revisions | (95.8) | (12.5) | 4.0 | (104.3) |
| Purchases | 161.8 | | | 161.8 |
| Extensions and discoveries | 537.5 | 24.5 | 25.1 | 587.1 |
| Production | (450.3) | (17.5) | (14.0) | (481.8) |
| **Proved reserves at December 31, 2010** | **4,635.0** | **151.4** | **135.2** | **4,921.6** |
| Revisions | (134.3) | (4.6) | (10.0) | (148.9) |
| Purchases | 9.9 | | | 9.9 |
| Divestitures | (12.8) | | | (12.8) |
| Extensions and discoveries | 1,065.5 | 18.6 | 19.3 | 1,103.4 |
| Production | (493.2) | (18.2) | (14.9) | (526.3) |
| **Proved reserves at December 31, 2011** | **5,070.1** | **147.2** | **129.6** | **5,346.9** |
| **Proved developed reserves at December 31, 2009** | **2,499.3** | **101.8** | **74.0** | **2,675.1** |
| **Proved developed reserves at December 31, 2010** | **2,684.4** | **90.1** | **80.7** | **2,855.2** |
| **Proved developed reserves at December 31, 2011** | **3,011.5** | **93.0** | **77.7** | **3,182.2** |

(1) Oil and natural gas liquids were converted to Bcfe using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as 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 regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

Purchases in 2009 and 2010 include proved developed reserves of 24 Bcfe and 42 Bcfe, respectively.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

Revisions in 2011 and 2010 primarily relate to the reclassification of reserves from proved to probable reserves attributable to locations not expected to be developed within five years. A significant portion of the revisions for 2009 are a result of the impact of the new SEC rules. Proved reserves are lower because of the lower 12-month average, first-of-the-month price as compared to the 2008 year-end price, and the revision of proved undeveloped reserve estimates based on new guidance.

Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit.

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

The following is based on the estimated quantities of proved reserves. Prices are based on the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. For the years ended December 31, 2011 and 2010 and 2009, the average domestic natural gas equivalent price, including deductions for gathering, processing and transportation, used in the estimates was $3.89, $3.48 and $2.62 per MMcfe, respectively. The increase in the equivalent price reflects the impact of oil and NGLs growth in our reserves. Future cash inflows for the years ended December 31, 2010 and 2009 reflect deductions for the estimates for gathering, processing and transportation. For the year ended December 31, 2011, the estimates for gathering, processing and transportation are included in production costs. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

**Standardized Measure of Discounted Future Net Cash Flows**

| As of December 31, 2010 | Domestic | International(1) | Entity s share of international equity method investee(2) |
|---|---|---|---|
| | | (Millions) | |
| Future cash inflows | $ 16,151 | $ 779 | $ 787 |
| Less: | | | |
| Future production costs | 4,927 | 273 | 278 |
| Future development costs | 2,960 | 89 | 92 |
| Future income tax provisions | 2,722 | 98 | 114 |
| Future net cash flows | 5,542 | 319 | 303 |
| Less 10 percent annual discount for estimated timing of cash flows | (2,728) | (121) | (117) |
| Standardized measure of discounted future net cash inflows | $ 2,814 | $ 198 | $ 186 |

| As of December 31, 2011 | Domestic | International(1) | Entity s share of international equity method investee(2) |
|---|---|---|---|
| Future cash inflows | $ 25,498 | $ 897 | $ 891 |
| Less: | | | |
| Future production costs | 11,738 | 340 | 336 |
| Future development costs | 3,484 | 126 | 117 |
| Future income tax provisions | 3,196 | 100 | 117 |
| Future net cash flows | 7,080 | 331 | 321 |
| Less 10 percent annual discount for estimated timing of cash flows | (3,489) | (132) | (124) |
| Standardized measure of discounted future net cash inflows | $ 3,591 | $ 199 | $ 197 |

(1) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.

(2) Represents Apco s 40.8% interest in Petrolera Entre Lomas S.A.

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

**Sources of Change in Standardized Measure of Discounted Future Net Cash Flows**

| For the Year Ended December 31, 2009 | Domestic | International(1) | Entity s share of international equity method investee(2) |
|---|---|---|---|
| | | (Millions) | |
| Standardized measure of discounted future net cash flows beginning of period | $ 3,173 | $ 175 | $ 131 |
| Changes during the year: | | | |
| Sales of oil and gas produced, net of operating costs | (1,006) | (49) | (45) |
| Net change in prices and production costs | (3,310) | (35) | (49) |
| Extensions, discoveries and improved recovery, less estimated future costs | 1,131 | | |
| Development costs incurred during year | 389 | 17 | 21 |
| Changes in estimated future development costs | 701 | (1) | (3) |
| Purchase of reserves in place, less estimated future costs | 171 | | |
| Revisions of previous quantity estimates | (923) | 79 | 88 |
| Accretion of discount | 450 | 21 | 17 |
| Net change in income taxes | 932 | (4) | (2) |
| Other | 5 | (28) | (29) |
| Net changes | (1,460) | | (2) |
| Standardized measure of discounted future net cash flows end of period | $ 1,713 | $ 175 | $ 129 |

| For the Year Ended December 31, 2010 | Domestic | International(1) | Entity s share of international equity method investee(2) |
|---|---|---|---|
| | | (Millions) | |
| Standardized measure of discounted future net cash flows beginning of period | $ 1,713 | $ 175 | $ 129 |
| Changes during the year: | | | |
| Sales of oil and gas produced, net of operating costs | (1,446) | (59) | (55) |
| Net change in prices and production costs | 1,921 | 34 | 43 |
| Extensions, discoveries and improved recovery, less estimated future costs | 724 | | |
| Development costs incurred during year | 633 | 26 | 25 |
| Changes in estimated future development costs | (292) | (12) | (15) |
| Purchase of reserves in place, less estimated future costs | 439 | 2 | |
| Revisions of previous quantity estimates | (332) | 26 | 63 |
| Accretion of discount | 220 | 22 | 17 |

| | | | |
|---|---|---|---|
| Net change in income taxes | (758) | (13) | (20) |
| Other | (8) | (3) | (1) |
| Net changes | 1,101 | 23 | 57 |
| Standardized measure of discounted future net cash flows end of period | $ 2,814 | $ 198 | $ 186 |

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**WPX Energy, Inc.**

**Supplemental Oil and Gas Disclosures (continued)**

**(Unaudited)**

| **For the Year Ended December 31, 2011** | **Domestic** | **International(1)** | **Entity s share of international equity method investee(2)** |
|---|---|---|---|
| | | **(Millions)** | |
| Standardized measure of discounted future net cash flows beginning of period | $ 2,814 | $ 198 | $ 186 |
| Changes during the year: | | | |
| Sales of oil and gas produced, net of operating costs | (1,194) | (64) | (61) |
| Net change in prices and production costs | 495 | 26 | 29 |
| Extensions, discoveries and improved recovery, less estimated future costs | 1,661 | | |
| Development costs incurred during year | 593 | 23 | 25 |
| Changes in estimated future development costs | (750) | (32) | (30) |
| Purchase of reserves in place, less estimated future costs | 15 | | |
| Sale of reserves in place, loss estimated future costs | (20) | | |
| Revisions of previous quantity estimates | (209) | 22 | 18 |
| Accretion of discount | 395 | 25 | 26 |
| Net change in income taxes | (226) | 6 | 4 |
| Other | 17 | (5) | |
| Net changes | 777 | 1 | 11 |
| Standardized measure of discounted future net cash flows end of period | $ 3,591 | $ 199 | $ 197 |

(1) Amounts attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.
(2) Represents Apco s 40.8% interest in Petrolera Entre Lomas S.A.

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**Item 9.** ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***
None.

**Item 9A.** ***Controls and Procedures***
**Disclosure Controls and Procedures**

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a 15(e) and 15d 15(e) of the Securities Exchange Act) (Disclosure Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

**Evaluation of Disclosure Controls and Procedures**

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

As disclosed in our Form 10 filing, we previously had identified two material weaknesses: one related to the timing of the recognition of certain compression deficiency obligations under compression service agreements, and one reflecting the aggregation of two significant deficiencies relating to aspects of depreciation, depletion and amortization of property, plant and equipment.

We have modified our internal controls related to contract reviews and monitoring of special contractual provisions for future contingent events. In addition, we performed reviews of all material historical gas management contracts in order to determine that no unidentified special provisions for future contingent events existed. We also modified our internal controls around our processes related to property, plant and equipment. We consider these items to be remediated and the identified material weaknesses no longer existed as of the end of the period covered by this report.

**Management s Annual Report on Internal Control over Financial Reporting**

This annual report does not include a report of management s annual assessment of internal control over financial reporting due to a transition period established by the rules of the Securities and Exchange Commission for newly public companies.

**Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting**

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting due to a transition period established by the rules of the Securities and Exchange Commission for newly public companies.

**Fourth Quarter 2011 Changes in Internal Controls**

Other than described above, there have been no changes during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

**Item 9B.** ***Other Information***

None.

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## PART III

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

The information called for by this Item 10 will be included in an amendment to this Annual Report on Form 10-K to be filed not later than April 30, 2012.

**Item 11.** ***Executive Compensation***

The information called for by this Item 11 will be included in an amendment to this Annual Report on Form 10-K to be filed not later than April 30, 2012.

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

The information called for by this Item 12 will be included in an amendment to this Annual Report on Form 10-K to be filed not later than April 30, 2012.

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

The information called for by this Item 13 will be included in an amendment to this Annual Report on Form 10-K to be filed not later than April 30, 2012.

**Item 14.** ***Principal Accountant Fees and Services***

The information called for by this Item 14 will be included in an amendment to this Annual Report on Form 10-K to be filed not later than April 30, 2012.

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# PART IV

**Item 15.** ***Exhibits and Financial Statement Schedules***

(a) 1 and 2.



(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

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## INDEX TO EXHIBITS

| Exhibit No. | Description |
|---|---|
| 2.1 | Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.  s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011) |
| 3.1 | Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 3.2 | Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 4.1 | Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.  s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011) |
| 10.1* | Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. |
| 10.2 | Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 10.3 | Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 10.4 | Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 10.5 | Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.  s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011) |
| 10.6# | Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.  s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011) |
| 10.7 | Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.  s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |
| 10.8 | Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.8 to WPX Energy, Inc.  s current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012) |

# Certain portions have been omitted pursuant to an Order Granting Confidential Treatment issued by the SEC on December 5, 2011. Omitted information has been filed separately with the SEC.

| Exhibit No. | Description |
|---|---|
| 10.9 | First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc. s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011) |
| 10.10 | Registration Rights Agreement, dated November 14, 2011, between WPX Energy, Inc. and the initial purchasers listed therein (incorporated herein by reference to Exhibit 10.1 to The Williams Companies, Inc. s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011) |
| 10.11 | WPX Energy, Inc. 2011 Incentive Plan (incorporated herein by reference to Exhibit 4.3 to WPX Energy, Inc. s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) |
| 10.12 | WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc. s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) |
| 10.13* | Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors |
| 10.14* | Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers |
| 10.15* | Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers |
| 10.16* | Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers |
| 21.1* | List of Subsidiaries |
| 23.1* | Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP |
| 23.2* | Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc. |
| 24.1* | Powers of Attorney |
| 31.1* | Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1* | Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99.1* | Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc. |

* Filed herewith
** Furnished herewith

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## 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.

WPX ENERGY, Inc.
(Registrant)
By: /s/ J. Kevin Vann
**J. Kevin Vann**
**Controller**

Date: February 28, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Ralph A. Hill | President, Chief Executive Officer and Director (Principal Executive Officer) | February 28, 2012 |
| /s/ Rodney J. Sailor | Senior Vice President and Chief Financial Officer (Principal Financial Officer) | February 28, 2012 |
| /s/ J. Kevin Vann | Controller (Principal Accounting Officer) | February 28, 2012 |
| /s/ Kimberly S. Bowers* * | Director | February 28, 2012 |
| /s/ John A. Carrig* * | Director | February 28, 2012 |
| /s/ William R. Granberry* * | Director | February 28, 2012 |
| /s/ Don J. Gunther* * | Director | February 28, 2012 |
| /s/ Robert K. Herdman* * | Director | February 28, 2012 |

| | | |
|---|---|---|
| /s/ Henry E. Lentz*<br>* | Director | February 28, 2012 |
| /s/ George A. Lorch*<br>* | Director | February 28, 2012 |
| /s/ William G. Lowrie*<br>* | Chairman of the Board | February 28, 2012 |
| /s/ David F. Work*<br>* | Director | February 28, 2012 |

*By: /s/ Stephen E. Brilz February 28, 2012

**Attorney-in-Fact**

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**WPX Energy, Inc.**

**SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS**

| | Beginning Balance | Charged (Credited) to Costs and Expenses | Other (Millions) | Deductions | Ending Balance |
|---|---|---|---|---|---|
| 2011: | | | | | |
| Allowance for doubtful accounts accounts and notes receivable(a) | $16 | $(1) | $ | $(2) | $13 |
| Deferred tax asset valuation allowance(a) | 22 | | | (6)(f) | 16 |
| 2010: | | | | | |
| Allowance for doubtful accounts accounts and notes receivable(a) | 19 | (3) | | | 16 |
| Deferred tax asset valuation allowance(a) | 22 | | | | 22 |
| Price-risk management credit reserves liabilities(b) | (3) | 3(d) | | | |
| 2009: | | | | | |
| Allowance for doubtful accounts accounts and notes receivable(a) | 25 | 3 | | (9)(c) | 19 |
| Deferred tax asset valuation allowance(a) | 22 | | | | 22 |
| Price-risk management credit reserves assets(a) | 6 | (3)(d) | (3)(e) | | |
| Price-risk management credit reserves liabilities(b) | (15) | 12(d) | | | (3) |

(a) Deducted from related assets.

(b) Deducted from related liabilities.

(c) Represents recoveries of balances previously written off.

(d) Included in revenues.

(e) Included in accumulated other comprehensive income (loss).

(f) Deferred tax asset retained by Williams.