WPX ENERGY, INC.
Form 10-K
February 27, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)

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

For the fiscal year ended December 31, 2013
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 1-35322
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.)
3500 One Williams Center, Tulsa, Oklahoma	74172-0172
(Address of Principal Executive Offices)	(Zip Code)

855-979-2012
(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 R No £

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

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 R No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 R 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. R

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	R	Accelerated filer	£
Non-accelerated filer	£ (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 R

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second quarter was approximately $3,775,544,298.

The number of shares outstanding of the registrant's common stock outstanding at February 26, 2014 was 201,737,171.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be delivered to stockholders in connection with its 2014 Annual Meeting of Stockholders are incorporated by reference into Part III.

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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.

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.

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.

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

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. Our principal executive office is located at 3500 One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 855-979-2012. 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 oil positions in the Williston Basin in North Dakota and the San Juan Basin in the southwestern United States. Our other areas of domestic operations include natural gas plays in the Appalachian Basin in Pennsylvania, the San Juan Basin, and the Powder River Basin in Wyoming. 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 3 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, 2013 were 4,905 Bcfe, comprised of 4,762 Bcfe in domestic reserves and 143 Bcfe in net international reserves. Our domestic reserves reflect a mix of 76.2 percent natural gas, 13.0 percent crude oil and 10.8 percent NGLs. During 2013, we replaced our domestic production for all commodities at a rate of 162 percent. For oil alone, we replaced 547 percent of our oil production. Our Piceance Basin operations form the majority of our proved reserves and current production, providing a low-cost, scalable asset base.

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 AND PROPERTIES

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 attractive rates of return on our investments.

- 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 grow our reserves and production in a manner that maximizes our returns on investments. 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.
- 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 have replicated these cost-efficient approaches in the Williston Basin.
- Target a More Balanced Commodity Mix in Our Production Profile through development and exploration. With our Williston Basin, Gallup Sandstone in the San Juan Basin and our liquids-rich Piceance Basin assets, we have a significant drilling inventory of oil and liquids-rich opportunities that we intend to develop 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. However, the newly discovered Niobrara shale formation is generally considered to be dry gas. We will continue to pursue other oil- and liquids-rich organic development and acquisition opportunities that meet our investment returns and strategic criteria.
- Pursue Efforts to Monetize Certain Assets and Redeploy Proceeds. From time to time we consider transactions that would monetize certain of our assets and enable us to redeploy the proceeds in areas where there is an opportunity for a higher return. In 2013, for example, we announced plans to consider the formation of a master limited partnership, or “MLP,” which would hold working interests in mature, producing natural gas properties located in the Piceance Basin in Colorado. Subject to final board approval and favorable market conditions, we expect to pursue these plans in the first half of 2014.
- Maintain Financial Liquidity and Manage Commodity Price Sensitivity. We plan to maintain 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 appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. As of February 26, 2014, our estimated domestic natural gas production revenues were approximately 61 percent hedged for 2014 and our estimated domestic oil production revenues were approximately 56 percent hedged for 2014.
- Optimize and Focus our Portfolio of Assets over Time. Our objective over time is to grow our production within our cash flow. With that in mind, we continuously evaluate the performance of our assets and, when appropriate, we consider divestitures of assets that are underperforming or which are no longer a part of our strategic focus. As previously announced, we are actively pursuing the potential disposition of our interests in Apco. We may consider additional divestitures under conditions that we deem appropriate.
- Pursue Significant Resource Potential through Exploration Activities. 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. 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.

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Significant Properties
Our principal areas of operation are the Piceance Basin, Williston Basin, San Juan Basin, Appalachian Basin, Powder River 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 2013, we operated an average of 6.6 drilling rigs in the basin, including 5.6 in the Piceance Valley and one in the Piceance Highlands. We expect to operate nine rigs in the Piceance Basin in 2014. In 2013, we had an average of 601 MMcf/d of net gas production from our Piceance Basin properties along with an average of 19.1 Mbbls/d of NGLs and 1.9 Mbbls/d of condensate recovered from our Piceance Basin properties. Capital expenditures were approximately $374 million which included the completion of 250 gross (237 net) wells in 2013. As of December 31, 2013, another 18 gross operated wells were awaiting completions. 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 6,000 to 9,000 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.
In early 2013, we announced a successful discovery in the Niobrara shale formation which has the potential to significantly increase our natural gas reserves and daily production in future years. The discovery well produced an initial high of 16 MMcf/d at a flowing pressure of 7,300 pounds per square inch. The Niobrara and Mancos Shales are generally located at depths of 10,000 to 13,000 feet. We have the lease rights to approximately 180,000 net acres of the Niobrara/Mancos Shale play that underlies our expansive leasehold position in the Piceance Basin. Substantial gathering and processing infrastructure is in place to accommodate additional gas volumes from the area, as is take-away capacity from the basin. Gas produced from the Niobrara and Mancos Shales can be processed without modification to existing gas treatment facilities. We plan to double our delineation drilling in 2014 with up to 10 wells expected and we also initiated 3D seismic work in the Piceance Valley to aid in the delineation. This activity will provide 70 percent seismic coverage of our Piceance Valley acreage.
Williston Basin
In December 2010, we acquired leasehold positions of approximately 85,800 net acres in the Williston Basin. All of these properties are on the Fort Berthold Indian Reservation in North Dakota and 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 and Three Forks formation, the primary targets for all of the well locations in our current drilling inventory.
During 2013, we operated an average of 4.1 rigs on our Williston Basin properties and we had an average of 14.8 Mboe/d of net production from our Williston Basin wells. Capital expenditures were approximately $476 million which included the completion of 51 gross (36 net) wells in 2013. As of December 31, 2013, another 12 gross operated wells were awaiting completion.
We are developing oil reserves through horizontal drilling in the Middle Bakken and plan to develop the Upper Three Forks Shale oil formations. Based on our subsurface geological analysis, we believe that our position lies in an area of the basin with substantial potential recovery for Bakken formation oil.

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.

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. 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 many operators are drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation, we believe that most of our Williston Basin acreage is prospective in the Three Forks formation.

Our acreage in the Williston Basin, 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, the 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.

San Juan Basin

We acquired our San Juan Basin properties as part of The Williams Companies, Inc. (“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 Mesaverde, Fruitland Coal and Mancos Shale formations which are predominantly gas bearing. We operate two units in New Mexico (Rosa and Cox Canyon) as well as a number of non-unit properties, and we operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We operate 878 wells in the San Juan Basin and also own interest in 2,328 wells operated by other operators in New Mexico and Colorado. We hold approximately 128,000 net acres in the gas window of the basin.

In 2013, we announced a successful oil discovery in the Mancos Gallup Sandstone in the San Juan Basin that has the potential to significantly increase our oil production and reserves in future years. At December 31, 2013, our leasehold position in the oil window of the San Juan Basin was approximately 32,000 net acres and we are targeting additional acreage. In early 2014, we have acquired approximately 12,000 additional net acres.

During 2013, we had an average of 123 MMcfe/d of net production from our San Juan Basin properties. Capital expenditures, including exploratory expenditures, were approximately $117 million which included the completion of 13 gross (13 net) wells from our oil properties. As of December 31, 2013, another 3 gross operated wells were awaiting completion.

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 feet with net thickness ranging from zero to 100 feet. The Mesaverde play is the top producing tight gas play in the basin with total thickness ranging from 500 to 2,500 feet. The Mesaverde is underlain by the upper Mancos Shale and overlain by the Lewis Shale. The Mancos Shale, locally referred to as the Gallup Sandstone, is found at a depth of approximately 5,400 feet and is fine-grained sandstone interval of approximately 150 feet thick. The Mancos Shale includes both oil and natural gas.

Some of our acreage in the San Juan Basin is leased to us by or with the approval of the federal government or its agencies, including the United States Forest Service (USFS), Bureau of Land Management (BLM), the Bureau of Indian Affairs (BIA), and the Federal Indian Minerals Office (FIMO). These particular leases are subject to federal authority, including the National Environmental Policy Act, and 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 both permits to drill and rights of way.

Appalachian Basin

Our Appalachian Basin acreage is located in three 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 and centrally in Clearfield and Centre Counties. We also have acreage in Columbia County in Pennsylvania. We have expanded our position since our entry into the Appalachian Basin in 2009, both organically and through third-party acquisitions. We are the primary operator on our acreage for the three areas. A third party gathering system provides trunkline service out of the Susquehanna area. This system experienced operational, maintenance and remediation efforts throughout much of 2013.

During 2013, we operated one rig on our Appalachian Basin properties and we had an average of 83 MMcfe/d of net production from our Appalachian Basin wells. Production levels were hampered for much of 2013 due to the issues discussed previously on the aforementioned third party gathering system. Capital expenditures were approximately $126 million which included the completion of 37 gross (24 net) wells in 2013. Our drilling program in the Appalachian Basin will be limited to completions in 2014. As of December 31, 2013, another 18 gross operated wells were awaiting completion. Additionally in 2013, we recorded impairment charges related to the Appalachian Basin. See Note 6 of Notes to Consolidated Financial Statements for further discussion.

The Marcellus Shale formation of the Appalachian Basin 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 806,482 acres, of which our ownership represents 360,002 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 2013, we had an average of 174 MMcfe/d of net production from our Powder River Basin properties. Capital expenditures were approximately $6 million which included the completion of 37 gross (16 net) wells in 2013. The majority of these wells were drilled in prior years and completed the dewatering process in 2012. In 2014, we expect a level of expenditures similar to our 2013 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 5 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.

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 52 percent oil, 44 percent natural gas and 4 percent liquefied petroleum gas.

During 2013, Apco had an average of 12.5 Mboe/d of net production.

Apco participated in the drilling of 31 gross wells operated by its partners in 2013. Apco spent, for its direct ownership interest, approximately $51 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, amounting to less than one percent of our assets, are primarily comprised of gas reserves in the Green River Basin of southwest Wyoming.

Acquisitions and Divestitures

Our acquisitions during 2013 consisted of miscellaneous leasehold purchases of $57 million with minimal associated production. The majority of these purchases were for oil exploration leaseholds. 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 Piceance, Williston and San Juan Basins located in 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 3 percent and 5 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

The following table sets forth our estimated domestic net proved developed and undeveloped reserves expressed by product and on a natural gas equivalent basis for the reporting periods December 31, 2013, 2012 and 2011.

	As of December 31, 2013				
	Gas (MMcf)	Oil (Mbbls)	NGL (Mbbls)	Equivalent (MMcfe)(a)	%
Proved Developed	2,265,204	36,828	48,587	2,777,695	58%
Proved Undeveloped	1,364,552	66,102	37,128	1,983,930	42%
Total Proved-Domestic	3,629,756	102,930	85,715	4,761,625	

	As of December 31, 2012				
	Gas (MMcf)	Oil (Mbbls)	NGL (Mbbls)	Equivalent (MMcfe)(a)	%
Proved Developed	2,170,681	23,740	64,910	2,702,579	60%
Proved Undeveloped	1,198,392	52,807	45,449	1,787,928	40%
Total Proved-Domestic	3,369,073	76,547	110,359	4,490,507	

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

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(a) 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, 2013.

	As of December 31, 2013			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Equivalent (MMcfe)
Piceance Basin	2,518,993	8,156	75,130	3,018,712
Williston Basin	46,111	88,690	9,086	632,763
Appalachian Basin	328,071	—	—	328,071
Powder River Basin	244,569	1	—	244,573
San Juan Basin	472,463	5,935	1,499	517,065
Other	19,549	148	—	20,441
Total Proved-Domestic	3,629,756	102,930	85,715	4,761,625

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 2013 year-end estimated proved reserves reflect an average natural gas price of $3.27 per Mcf, an average oil price of $92.16 per barrel and average NGL price of $37.45 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 respective location price differentials. During 2013, we added 534 Bcfe of additions to our proved reserves. During 2013, we participated in the drilling of 416 gross wells at a net capital cost of approximately $1,022 million, which includes costs associated with nine exploratory wells.

Proved reserves reconciliation

PROVED U.S. RESERVES RECONCILIATION CHART
Bcfe
The 534 Bcfe of Extensions and Discoveries reflects 127 Bcfe added for drilled locations and 407 Bcfe added for new proved undeveloped locations. The extensions and discoveries were primarily in the Piceance Basin, Williston Basin, Appalachia Basin and San Juan Basin. The overall net positive revisions of 177 Bcfe reflects 133 Bcfe of net positive revisions made to developed reserves and 44 Bcfe of net positive revisions made to undeveloped reserves.
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 pervasiveness 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.
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 as appropriate. The compensation of our reserves analysis team is not directly linked to reserves additions or revisions except to the extent that reserves additions are a component of our all-employee incentive plan.

Approximately 99 percent of our total year-end 2013 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, 2013 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. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserves audit is our Director of Reserves and Production Services. The Director’s qualifications include 31 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, 2013, our proved undeveloped reserves were 1,984 Bcfe, an increase of 196 Bcfe over our December 31, 2012 proved undeveloped reserves estimate of 1,788 Bcfe. During 2013, 257 Bcfe of our December 31, 2012 proved undeveloped reserves were converted to proved developed reserves at a cost of $414 million. An additional 192 Bcfe of proved developed reserves was added to total proved reserves due to the development of unproved locations. Combined extensions and revisions of proved undeveloped reserves were 451 Bcfe of which 407 Bcfe were extensions of previously unproved locations and the remainder of 44 Bcfe are the total net revisions to proved undeveloped reserves.

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

Oil and Gas Production, Production Prices and Production Costs

The following table summarizes our net production sales for the years indicated.

	Year Ended December 31,		
	2013	2012	2011
Production Sales Data:			
Natural Gas (MMcf)			
U.S.			
Piceance Basin	219,317	246,179	247,700
Other(a)	140,146	151,303	141,080
International(b)	6,534	7,061	7,389
Total	365,997	404,543	396,169
Oil (Mbbls)			
U.S.	5,928	4,394	2,651
International(b)	2,032	2,178	2,054
Total	7,960	6,572	4,705
NGLs (Mbbls)			
U.S.			
Piceance Basin	6,963	10,075	9,902
Other(a)	458	317	155
International(b)	167	181	183
Total	7,588	10,573	10,240
Combined Equivalent Volumes (MMcfe)(b)	459,287	507,416	485,840
Combined Equivalent Volumes (Mboe)(b)	76,548	84,569	80,793
Average Daily Combined Equivalent Volumes (MMcfe/d)			
U.S.			
Piceance Basin	727	852	855
Other(a)	477	476	419
International(b)	54	58	57
Total	1,258	1,386	1,331

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(a) Excludes production from our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.

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

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

	Year Ended December 31, 2013	2012	2011
Domestic realized average price per unit(a):			
Natural gas:			
Natural gas excluding all derivative settlements (per Mcf)	$2.97	$2.32	$3.48
Impact of hedges (per Mcf)	0.02	1.06	0.84
Natural gas including hedges (per Mcf)	2.99	3.38	4.32
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)	(0.06)	0.03	—
Natural gas net price including all derivative settlements (per Mcf)	$2.93	$3.41	$4.32
Oil:			
Oil excluding all derivative settlements (per barrel)	$90.21	$83.35	$84.91
Impact of hedges (per barrel)	—	2.23	0.39
Oil including hedges (per barrel)	90.21	85.58	85.30
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	1.52	0.35	—
Oil net price including all derivative settlements (per barrel)	$91.73	$85.93	$85.30
NGL:			
NGL excluding all derivative settlements (per barrel)	$30.70	$28.56	$40.17
Impact of hedges (per barrel)	—	—	—
NGL including hedges (per barrel)	30.70	28.56	40.17
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	0.07	1.56	—
NGL net price including all derivative settlements (per barrel)	$30.77	$30.12	$40.17
Combined commodity price per Mcfe, including all derivative settlements(b)	$4.15	$4.21	$4.96

(a) Excludes our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.
(b) Realized average prices reflect realized market prices, net of fuel and shrink.

	Year Ended December 31, 2013	2012	2011
Domestic expenses per Mcfe(a):			
Production costs:			
Lifting costs and workovers	$0.51	$0.44	$0.43
Facilities operating expense	0.06	0.03	0.03
Other operating and maintenance	0.05	0.05	0.05
Total LOE	$0.62	$0.52	$0.51
Gathering, processing and transportation charges	0.98	1.04	1.05
Taxes other than income	0.27	0.18	0.24
Total production cost	$1.87	$1.74	$1.80
General and administrative	$0.62	$0.56	$0.57
Depreciation, depletion and amortization	$2.06	$1.93	$1.89

(a) Excludes our Barnett Shale and Arkoma Basin operations, which were the subject of a disposition in 2012.

Productive Oil and Gas Wells

The table below summarizes 2013 productive wells by area (a).

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance Basin	4,748	4,326	—	—
Williston Basin	—	—	161	94
Appalachian Basin	141	80	—	—
Powder River Basin	4,873	2,101	—	—
San Juan Basin	3,193	855	13	13
Other(b)	1,104	26	—	—
Total	14,059	7,388	174	107

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(a) 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.

(b) Other includes Green River Basin and miscellaneous smaller properties.

At December 31, 2013, there were 231 gross and 110 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2013.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance Basin	134,163	103,950	154,375	117,236	288,538	221,186
Williston Basin	61,687	54,774	27,289	25,962	88,976	80,736
Appalachian Basin	36,169	26,620	77,064	61,374	113,233	87,994
Powder River Basin	621,975	278,706	184,507	81,296	806,482	360,002
San Juan Basin	229,959	116,238	51,582	44,587	281,541	160,825
Other(a)	31,850	6,131	385,121	247,560	416,971	253,691
Total	1,115,803	586,419	879,938	578,015	1,995,741	1,164,434

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(a) Other includes exploratory acreage in Montana and Kansas and miscellaneous smaller properties.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was 100 percent in 2013, 100 percent in 2012 and approximately 99 percent in 2011.

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

	2013		2012		2011	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance Basin	249	236	239	208	385	361
Williston Basin	51	36	41	27	25	20
Appalachian Basin	37	24	54	33	36	17
Powder River Basin	37	16	150	92	523	225
San Juan Basin	9	9	11	6	56	33
Other(a)	24	—	52	—	212	34
Productive, development	407	321	547	366	1,237	690
Productive, exploration (b)	9	9	1	1	2	2
Total Productive	416	330	548	367	1,239	692
Dry, development	—	—	—	—	2	1
Dry, exploration	—	—	—	—	—	—
Total Drilled	416	330	548	367	1,241	693

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(a) Other includes Green River Basin and miscellaneous smaller properties.
(b) Productive, exploration includes 4 wells in the Gallup Sandstone in the San Juan Basin.

Total gross operated wells drilled were 361 in 2013, 423 in 2012 and 758 in 2011.

Present Activities

At December 31, 2013, we had 18 gross (14 net) wells in the process of being drilled. As previously noted in Significant Properties, we also have a large number of wells that are awaiting completion.

Scheduled Lease Expirations

Domestic

The table below sets forth, as of December 31, 2013, 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.

	2014	2015	2016	2017+	Total
Piceance Basin	17,766	777	4,836	11,362	34,741
Williston Basin	840	—	—	906	1,746
Appalachian Basin	11,258	22,073	14,768	12,379	60,478
Powder River Basin	10,278	157	39	1,667	12,141
San Juan Basin	—	160	—	6,720	6,880
Other	25,406	49,300	99,179	130,576	304,461
Total (Gross Acres)	65,548	72,467	118,822	163,610	420,447
	2014	2015	2016	2017+	Total
Piceance Basin	10,269	398	4,091	10,442	25,200
Williston Basin	456	—	—	902	1,358
Appalachian Basin	7,845	19,259	12,517	8,577	48,198
Powder River Basin	7,125	78	19	834	8,056
San Juan Basin	—	144	—	6,720	6,864
Other	24,554	38,843	83,354	83,655	230,406
Total (Net Acres)	50,249	58,722	99,981	111,130	320,082

International

In general, all of our concessions have expiration dates of either 2025 or 2026, except for two concessions that expire beyond 2030 and one that expires in 2016. With respect to this concession, we are negotiating a ten-year extension for which we have contractual rights. This concession represents approximately 49,000 acres net to Apco or approximately 34,000 acres net to WPX based on our 69 percent 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 between 2014 and 2017 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, oil and NGL production along with third party purchases and sales of natural gas, which includes natural gas purchased from working interest owners in operated wells and other area third party producers. Through May 1, 2012, this activity included sales of natural gas to Williams Partners for use in its midstream business. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related price risk management activity. 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. Transportation capacity demand payments associated with contracts that are currently not utilized to support our development activities are captured as an expense item in gas management.

Delivery Commitments

We hold a long-term obligation to deliver and sell 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. This obligation expires in November 2014.

Purchase Commitments

In December 2010, we entered a long-term obligation to purchase 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 temporarily constrained thus amplifying localized price volatility. 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 summer 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, crude oil and NGL properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Customers

Natural gas, oil and NGL 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 under various pricing structures. Our third party customers include other producers, utility companies, power generators, banks, marketing and trading companies and midstream service providers. In 2013, natural gas sales to BP Energy Company, Southern California Gas Company and Williams accounted for approximately 15 percent, 11 percent and 8 percent of our consolidated revenues, respectively. 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 other purchasers, 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;
- the notice to surface owners and other third parties; and
- the use, maintenance and restoration of roads and bridges used during all phases of drilling and production.

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.

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.

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 Bureau of Land Management ("BLM"), and the Environmental Protection Agency ("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 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, EPA's 2011 – 2013 and 2014 – 2016 National Enforcement Initiatives include Energy Extraction and "Assuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that 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. 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. 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 restrict 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. In 2012, the EPA issued federal regulations affecting our operations under the New Source Performance Standards (“NSPS”) provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants (“NESHAP”), although implementation of some of the more rigorous requirements is not required until 2015.

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.

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 670,000 acres and represents approximately 93 percent 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 28 percent 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 six 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, (v) setback requirements as to the location of waste disposal areas, and (vi) pre- and post-drilling groundwater sampling. 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.

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 is required by the Colorado Oil and Gas Conservation Commission (“COGCC”) and may be required by BLM as a condition of approval for the drilling permit.
- 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 Williston Basin or the New Mexico portion of our San Juan Basin assets. We plan to begin voluntarily conducting water monitoring in the Williston Basin. 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.

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

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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 fractures 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 percent 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. Through December 31, 2013, we have loaded data on more than 1,140 wells, including data relating to 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 2013, we used 99.9 percent 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.

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 have considered 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. 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 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, and on May 10, 2012, the EPA published its proposed guidance on the issue. The public comment period for the proposed permitting guidance closed on August 23, 2012, and the EPA has yet to issue any final guidance. 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, which are expected to be published in a draft report for public and peer review in 2014, 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 and responded to 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 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, Colorado, North Dakota, New Mexico and Wyoming, have adopted or are considering adopting, regulations that could restrict or impose additional requirements related to hydraulic fracturing. For example, Pennsylvania 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. Wyoming requires public disclosure of chemicals used in hydraulic fracturing. 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. A number of states have also adopted regulations increasing the setback requirements, or are in the process of rulemaking to address the issue, including Colorado, New Mexico and Pennsylvania.

In addition, a number of local governments in Colorado 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 Appalachian Basin and San Juan Basin in New Mexico 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. Certain organizations have promoted ballot initiatives at the local level that are aimed at imposing restrictions on hydraulic fracturing, and may attempt to do the same on a wider basis in one or more states where we operate. 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. The 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, and our reporting began 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 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 Colombia 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, 2013, 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 17 of our Notes to Consolidated Financial Statements for financial information with respect to our segments' revenues, profits or losses, and total assets.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Item 8—Financial Statements and Supplementary Data—Note 17 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 17 of 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., 3500 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. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "potential," "projects," "scheduled," "will" or other similar expressions. These forward-looking 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 natural gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Acquisitions or divestitures
- Seasonality of our business; and
- Natural gas, natural gas liquids ("NGLs") and crude oil 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 regulation 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."

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."

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 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. We expect to fund our capital expenditures through a combination of cash flows from operations and, when appropriate, borrowings under our credit facility. 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,

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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;
- 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.

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, due to the drop in natural gas and natural gas liquids prices during 2013 and more significantly in the fourth quarter, we performed annual and interim assessments of our proved and unproved properties. As a result, we recorded impairments of capitalized costs of certain natural gas properties of $1.4 billion in 2013. 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 costs of acquired unproved reserves, 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 64 percent could be at risk for impairment if forward natural gas and NGL prices across all future periods decline by approximately 6 percent to 8 percent, on average, as compared to the forward prices at December 31, 2013. We estimate that approximately 28 percent could be at risk for impairment if forward oil prices across all periods decline by approximately 11 percent to 13 percent. 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.

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 42 percent of our total estimated proved reserves at December 31, 2013 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 present 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 Appalachian Basin 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:

- Weather conditions;
- The level of consumer demand;
- The overall economic environment;
- 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;
- 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 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 Williston Basin and Appalachian Basin or that we will be able to obtain sufficient transportation capacity on economic terms.

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, 2013 , we were not the operator of approximately 13 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 and reduce our liquidity.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), which was enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Title VII of the Dodd-Frank Act ("Title VII") provides for new statutory and regulatory requirements for derivative transactions in the major energy markets, including swaps, hedging and other transactions. Among other things, Title VII provides that transactions be cleared on a derivatives clearing organization if those transactions are within a class of swaps designated by the the Commodity Futures Trading Commission (the "CFTC") for clearing. As of February 27, 2014, the CFTC had only designated certain classes of interest rates swaps and index credit default swaps for mandatory clearing, and it is unclear when the CFTC will designate other classes of swaps, such as physical commodity swaps, for mandatory clearing. The clearing of such transactions would require us to post cash or other liquid collateral in connection with those transactions. Moreover, certain of the transactions required to be cleared will have to be executed on boards of trade. If the derivative transactions into which we enter are not required to be cleared, new regulations expected to be adopted by the CFTC and banking regulators may require us to comply with requirements to post margin with our counterparties for uncleared swaps, although these regulations are not final and how the final regulations will affect us is uncertain at this time. Title VII also provides for the creation of position limits for certain core futures and equivalent swaps contracts for or linked to certain physical commodities, including Henry Hub natural gas and light sweet crude oil. The CFTC recently proposed new position limits rules that set limits on the positions in such contracts that market participants could hold, subject to exceptions for certain bona fide hedging transactions intended to hedge certain price risks. A rule recently adopted under the Dodd-Frank Act, commonly referred to as the “Volcker Rule,” may also require certain of the counterparties to our

derivative instruments to spin off some of their derivatives activities to separate entities. Those separate entities would be our counterparties in future swaps and may not be as creditworthy as our current counterparties.
The final impact of the Dodd-Frank Act on our hedging activities is uncertain at this time due to the fact that the SEC, the CFTC and other federal regulatory bodies that have involvement in this area have yet to complete the adoption and implementation of all of the rules and regulations required to implement the swap provisions of the Dodd-Frank Act. Although we believe the derivative contracts that we enter into should not be impacted by position limits and that we should generally be eligible to elect the exception from any requirement to clear our hedging transactions through a clearing organization and execute those transactions on an exchange, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC and other federal regulators, among other factors.

Compliance with the regulations adopted and to be adopted by the CFTC and other federal regulatory bodies may significantly increase the cost of entering into and maintaining derivative contracts. The increased costs may include costs associated with swap recordkeeping and reporting requirements and any required posting of cash or other liquid collateral for our commodities hedging transactions under circumstances in which we do not currently do so. Posting of such additional cash or liquid collateral could also impact our liquidity and reduce our cash available for capital expenditures and reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. The Dodd-Frank Act and related swaps regulations may lead to material alterations of the terms of derivative contracts we enter, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the related regulations, our results of operations may become more volatile and may be otherwise adversely affected and our cash flows may be less predictable. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act is to lower commodity prices.
Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, liquidity and cash flows.
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.

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.

In 2012, the Argentine government asserted that certain exploration and production companies operating in Argentina had not invested sufficiently to overcome Argentina's domestic production declines, thereby leading to reduced levels of oil and natural gas production as well as reductions in oil and natural gas proved reserves. On that basis, six provinces rescinded certain of Repsol YPF S.A.'s ("YPF") and other producers' concessions. In addition, the federal government expropriated a majority interest in YPF, the largest oil producing company in Argentina. If the government subjectively determines that we have not sufficiently invested in our properties, it could take action with regard to our concessions before our contract terms expire.

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 senior 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.

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, as well as their own reporting requirements. 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 Greenhouse Gas Reporting Program ("GHGRP"). 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 each year in March under this rule. The EPA publishes the data on its website. 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.

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 affecting 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;
- 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 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 were extended by the EPA for fiscal years 2014 to 2016, and which include Energy Extraction and "Assuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." 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 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.

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. Recently, there has been heightened debate about the hydraulic fracturing process 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. If adopted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, 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. 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 EPA published its “Status Report” in December 2012 and expects to publish results for public and peer review in 2014. 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.

Several states have 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, Colorado, North Dakota and New Mexico). Certain organizations have prompted ballot initiatives at the local level that are directed at imposing restrictions on hydraulic fracturing, and such ballot initiatives may be attempted on a wider basis in one or more states where we operate. 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 Appalachian Basin, San Juan Basin, Williston Basin 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 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 Williston Basin, 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 changes to certain federal income tax deductions currently available with respect to oil and gas exploration and production.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws 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 for the periods for which the filings are made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation, it could have a material adverse effect on us.

President Obama has proposed changes to certain federal income tax provisions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) repeal of the percentage depletion allowance for oil and gas properties; (ii) elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; (iii) repeal of the manufacturing deduction for certain U.S. production activities; and (iv) 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. Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition and results of operations.

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.

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 services are currently provided by our outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which our 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.

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, it may not be available on commercially reasonable terms. 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.

We entered into a number of agreements with The Williams Companies prior to our separation or "spin-off" from that company on December 31, 2011. 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. More financing may also be necessary if we are unable to execute dispositions of assets that are underperforming or which are no longer a part of our strategic focus. 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.

If there is a determination that the spin-off from Williams 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 to the effect that the spin-off would not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams, and Williams' stockholders. In addition, Williams received a private letter ruling 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. The private letter ruling and opinion relied on certain facts, assumptions, representations and undertakings from Williams and us. 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. Further, under the tax sharing agreement, we are required to indemnify Williams against tax-related liabilities that may be incurred by Williams relating to the spin-off, to the extent caused by our breach of any representations or covenants made with respect to the spin-off. These liabilities include the substantial tax-related liability that would result if the spin-off of our stock to Williams' stockholders failed to qualify as a tax-free transaction. The IRS is currently auditing Williams' 2011 consolidated federal income tax return that includes the spin-off.

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 were included in Williams' consolidated group for federal income tax purposes as well as any combined, consolidated or unitary tax returns of Williams for state or local income tax purposes. Under the tax sharing agreement, for each period in which we were consolidated or combined with Williams for purposes of any tax return, a pro forma tax return was prepared for us as if we filed our own consolidated, combined or unitary return. For any adjustments to the pro forma tax returns following the spin-off we will reimburse Williams for any additional taxes shown on the pro forma tax returns, and

Williams will reimburse us for reductions in the taxes shown on the pro forma tax returns. In addition, Williams will effectively control all of our tax decisions in connection with any Williams consolidated, combined or unitary income tax returns in which we are included. Thus 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. The IRS completed its audits of Williams’ 2009 and 2010 consolidated federal income tax returns during 2012. Williams’ 2011 consolidated federal income tax return is currently being audited by the IRS.

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.
Risks Related to Our Common Stock
Future issuances of our common stock may depress the price of our common stock.
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.
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 percent 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 11 of our Notes to Consolidated Financial Statements for the information that is called for by this item.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WPX". The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange.

	Years Ended December 31,			
	2013		2012	
	High	Low	High	Low
Common Stock:				
Fourth quarter	$23.69	$17.54	$18.31	$14.43
Third quarter	$20.36	$18.10	$17.73	$14.15
Second quarter	$21.11	$14.87	$18.90	$13.22
First quarter	$16.98	$14.03	$19.74	$14.20

At February 26, 2014, there were 8,477 holders of record of our common stock.

We have not paid or declared any cash dividends on our common stock. Any decision as to future payment of dividends is subject to the discretion of our Board of Directors.

Item 6. Selected Financial Data

The following financial data at December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, 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 results for periods prior to 2012 should not be relied upon as an indicator of our future performance.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(Millions, except per share amounts)				
Statement of operations data:					
Revenues	$2,761	$3,189	$3,882	$3,935	$3,586
Income (loss) from continuing operations(a)	$(1,191)	$(233)	$(150)	$(937)	$182
Income (loss) from discontinued operations(b)	—	22	(142)	(346)	(42)
Net income (loss)	(1,191)	(211)	(292)	(1,283)	140
Less: Net income attributable to noncontrolling interests	(6)	12	10	8	6
Net income (loss) attributable to WPX Energy, Inc.	$(1,185)	$(223)	$(302)	$(1,291)	$134
Basic and diluted earnings (loss) per common share:					
Income (loss) from continuing operations	$(5.91)	$(1.23)	$(0.81)	$(4.80)	$0.89
Income (loss) from discontinued operations	$—	$0.11	$(0.72)	$(1.75)	$(0.21)

	As of December 31,				
	2013	2012	2011	2010	2009
	(Millions)				
Balance sheet data:					
Notes payable to Williams—current(c)	$—	$—	$—	$2,261	$1,216
Long-term debt	1,916	1,508	1,503	—	—
Total assets	8,429	9,456	10,432	9,846	10,553
Total equity(c)	4,210	5,371	5,759	4,484	5,390

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(a) Income (loss) from continuing operations for the year ended December 31, 2013 includes $1,055 million of impairment charges primarily related to producing properties in the Appalachian Basin and Powder River Basin and costs of acquired unproved reserves in the Powder River Basin and Piceance Basin. In addition, income (loss) from continuing operations for 2013 includes a $317 million impairment charge to estimated fair value of unproved leasehold costs in the Appalachian Basin, $20 million impairment on our equity method investment, as well as, a $36 million gain on the sale of leasehold for deep rights in the Powder River Basin. Income (loss) from continuing operations for the year ended December 31, 2012 includes $225 million of impairment charges related to producing properties in the Green River Basin and costs of acquired unproved reserves in the Piceance and Powder River Basins. Income (loss) from continuing operations for the year ended December 31, 2011 includes $367 million of impairment charges related to producing properties and costs of acquired unproved reserves in the Powder River Basin. Income (loss) from continuing operations for the year ended December 31, 2010 includes a $1 billion impairment charge related to goodwill and a $175 million impairment charge related to costs of acquired unproved reserves in the Piceance Basin. See Note 6 of Notes to Consolidated Financial Statements for further discussion of the impairments in 2013, 2012 and 2011.

(b) Income (loss) from discontinued operations includes the results from holdings in the Barnett Shale and Arkoma Basin that were sold in 2012. The activity in the years 2009 through 2012 primarily relates to the Barnett Shale and Arkoma Basin operations. Activity in 2012 also reflects a $38 million pre-tax gain on the sale of the Barnett Shale and Arkoma Basin. Activity in 2011 and 2010 reflects pre-tax impairment charges of $180 million and $503 million, respectively, related to the Barnett Shale operations.

(c) On June 30, 2011, all of our notes payable to Williams were canceled 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 that was partially offset by a $981 million cash distribution to Williams. See Part II, Item 8, Financial Statements and Supplementary Data for activity related to our equity at December 31, 2013 and 2012.

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 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 oil positions in the Williston Basin in North Dakota and the San Juan Basin in the southwestern United States. Our other areas of domestic operations include natural gas plays in the Appalachian Basin in Pennsylvania, the San Juan Basin and the Powder River Basin in Wyoming. In addition, we own a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ("Apco") which has oil and gas activities 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 sales and marketing activities that include the sale of our natural gas, oil and NGL production, along with third party purchases and sales of natural gas, which include natural gas purchased from working interest owners in operated wells and other area third party producers. Through May 1, 2012, this activity also included sales of natural gas to Williams Partners L.P. ("Williams Partners") for use in its midstream business. 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 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. Due to the seasonal aspects of the transportation and storage contracts utilized to manage our third party marketing obligations, our quarter to quarter results may vary with economic gains in the winter months and losses in the summer months.

WPX Energy, Inc. was formed in 2011 to effect the separation from The Williams Companies, Inc. ("Williams") of Williams' exploration and production business. The spin-off was completed by way of a pro rata distribution on December 31, 2011 of WPX common stock to Williams' stockholders.

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".

Basis of Presentation

The consolidated financial statements for 2011 included elsewhere in this Form 10-K, principally represent the Exploration & Production segment of Williams of which the legal entities were contributed to WPX in 2011. Through December 2011, our results included allocations of costs for corporate functions historically provided to us by Williams. See Note 3 of the Notes to Consolidated Financial Statements for more information.

Our management believes the assumptions and methodologies underlying the allocation of expenses from Williams were 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.

In second-quarter 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. These properties represented less than 5 percent of our year- end 2011 proved domestic reserves and approximately 5 percent of total production in 2011. We have reported the results of operations and financial position of Barnett Shale and Arkoma operations as discontinued operations. Unless otherwise noted, the following discussion relates to our continuing operations.

Overview

The following table presents our production volumes and financial highlights for 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
Production Sales Volume Data:(a)			
Domestic:			
Natural gas (MMcf)	359,463	397,483	388,780
Oil (MBbls)	5,928	4,394	2,651
NGLs (MBbls)	7,421	10,392	10,057
Domestic combined equivalent volumes (MMcfe)(b)	439,554	486,198	465,030
Domestic combined equivalent volumes (MBoe)	73,259	81,033	77,505
International combined equivalent volumes (MMcfe)(b)(c)	19,733	21,218	20,810
Total WPX combined equivalent volumes (MMcfe)(b)(c)	459,287	507,416	485,840
Production Sales Volume Per Day:			
Domestic:			
Natural Gas (MMcf/d)	985	1,086	1,065
Oil (MBbls/d)	16	12	7
NGL (MBbls/d)	20	28	28
Domestic combined equivalent volumes (MMcfe/d)(b)	1,204	1,328	1,274
International combined equivalent volumes (MMcfe/d)(b)(c)	54	58	57
Total WPX per day combined equivalent volumes (MMcfe/d)(b)(c)	1,258	1,386	1,331
Financial Data (millions):			
Total domestic revenues	$2,609	$3,052	$3,772
Total international revenues	$152	$137	$110
Consolidated operating income (loss)	$(1,748)	$(280)	$(142)
Consolidated capital expenditures	$(1,154)	$1,521	$1,572

(a) Excludes production from our Barnett Shale and Arkoma Basin operations which are classified as discontinued operations.

(b) 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.

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

Our 2013 operating results were $1,468 million unfavorable as compared to 2012. The primary unfavorable impact includes $1.4 billion recorded in the fourth quarter 2013 for impairments of producing properties, costs of acquired unproved reserves and leasehold costs as compared to $225 million of impairments recorded in 2012 (see Note 6 of Notes to Consolidated Financial Statements). Significant declines in the forward natural gas prices relative to the forward prices at December 31, 2012 and more notably in the fourth quarter 2013, especially the Appalachia index prices, were the primary factors for the impairments. Additional unfavorable impacts include the absence of $423 million of gains realized in 2012 on natural gas derivatives designated as hedges for accounting purposes, $202 million unfavorable change in derivatives not designated as hedges, $90 million related to lower domestic natural gas production volumes and $85 million related to lower domestic NGL production volumes. Operating results were favorably impacted by $218 million related to higher domestic realized natural gas prices (excluding hedges), $168 million from higher domestic oil production volumes and prices (excluding hedges), $73 million lower gathering, processing and transportation costs, and a $36 million gain in 2013 on the sale of Powder River Basin deep rights leasehold.

While our total 2012 domestic production volumes increased over 2011, our 2012 results were impacted by lower realized natural gas prices (including hedges) coupled with lower natural gas liquids prices relative to 2011. Also, as a result of declines in forward natural gas prices during 2012 compared to 2011, we recorded impairments of producing properties and costs of acquired unproved reserves totaling $225 million during 2012. Our 2011 results were also impacted by impairment charges of $367 million on certain producing properties in 2011. See Note 6 of Notes to Consolidated Financial Statements.

Outlook

In 2014, we will continue our focus of growing our oil production and developing oil reserves, primarily those located in the Williston Basin and the Gallup Sandstone in the San Juan Basin. More than half of our planned 2014 capital expenditures are in domestic oil properties which includes a goal of 62 oil wells (gross) in the Williston Basin, an increase of 25 percent versus 2013, and 29 oil wells (gross) in the Gallup Sandstone which would nearly double 2013 activity.

We will also continue to focus our natural gas drilling effort in the Piceance Basin because of our scale and efficiency of that operation combined with significant infrastructure already in place. We have a goal of increasing our natural gas volumes over current production in the Piceance Basin by planning to deploy an average of nine drilling rigs in the Piceance Basin for 2014 which includes drilling focused on the Niobrara Shale discussed below. Our drilling program in the Appalachian Basin will be limited to completions in 2014. We are working to resolve constraints on our third party gatherer's system in Susquehanna County and may resume development in 2015.

We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities and negotiating cost savings on vendor contracts. Additionally, we are undertaking extensive review of our general and administrative costs and services.

Also in 2014, we will evaluate transactions that would monetize certain of our assets and enable us to redeploy the sales proceeds in areas where there is an opportunity for a higher return. These transactions could include the sale or contribution of mature, producing natural gas properties located in the Piceance to a master limited partnership (“MLP”). As previously announced, we have begun the process of forming an MLP although it is subject to final board approval and favorable market conditions.

Approximately 12 percent of our estimated annual capital spending in 2014 will be for exploratory activities, primarily for further delineation of our Niobrara Shale discovery in the Piceance Basin. We are also in the process of drilling test wells in other new areas. We will also continue to evaluate the purchase of leasehold in these and other areas. Our initial Niobrara Shale discovery well in the Piceance Basin produced 2.2 billion cubic feet of natural gas production in the first year of operation. We drilled four additional wells in 2013, two of which are producing, one that is a vertical test well and one that is being evaluated for alternatives due to a casing issue in the lateral section before completion began. Initial drilling thus far has validated the existence of a highly pressured continuous gas accumulation capable of producing pipeline-quality gas. Future drilling will focus on driving down costs while optimizing completion techniques. We plan to double our Niobrara delineation drilling in 2014 with up to 10 wells expected and we also initiated 3-D seismic work in the Piceance Valley to aid in the delineation. This activity will provide 70 percent seismic coverage of our Piceance Valley acreage.

We anticipate our total capital spending in 2014 will be up to $1.5 billion. The execution of transactions to monetize certain of our assets as previously mentioned is an important component to achieving the necessary capital to fund our spending program. If we are unable to successfully execute on assets sales, we may reduce our capital spending or make additional borrowings on our revolver. Our 2013 capital expenditures totaled approximately $1.15 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;
- Continuing to diversify our commodity portfolio through the development of our Williston Basin oil play position, Gallup Sandstone oil play and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- Fully delineating Niobrara Shale potential through drilling and 3-D seismic;
- Continuing to pursue cost improvements and efficiency gains;
- Continuing to invest in exploration projects to add new development opportunities to our portfolio;
- 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; and
- Continuing to maintain an active economic hedging program around our commodity price risks.

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

- Lower than anticipated energy commodity prices;
- Higher capital costs of developing our properties;
- Lower than expected levels of cash flow from operations;

- Lower than expected proceeds from asset sales;
- Counterparty credit and performance risk;

- General economic, financial markets or industry downturn;
- Changes in the political and regulatory environments;
- Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation;
- Decreased drilling success; and
- Unavailability of capital.

Currently the forward natural gas prices for 2014 are higher than our realized prices for 2013. However, forward natural gas and oil prices for 2015 and after are lower than the 2014 prices. Changes in the forward prices will be considered as we proceed with our 2014 capital program. Additionally, if forward natural gas prices were to decline by 6 to 8 percent or forward oil prices were to decline by 11 to 13 percent as compared to the forward prices at December 31, 2013, we would need to review a substantial portion of the producing properties net book value for impairment. With the exception of potential impairments, 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.

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. We have the following contracts as of February 26, 2014 for over 50 percent of our estimated daily domestic production in 2014, shown at weighted average volumes and basin-level weighted average prices:

Natural Gas	2014 Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed-price—Henry Hub	323	$ 4.21
Swaptions—Henry Hub	50	$ 4.24
Collars—Henry Hub	184	$ 4.04 - $4.66
Basis swaps—Northeast	23	$ 0.09
Basis swaps—Mid-Continent	197	$ (0.18)
Basis swaps—West	50	$ 0.10
Basis swaps—Rockies	104	$ (0.23)
Crude Oil	2014 Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed-price—WTI	13,243	$ 94.82
Basis swaps—Brent	4,463	$ 9.64

Natural Gas Liquids	2014 Volume (Bbls/d)	Weighted Average Price ($/Gal)
Fixed-price—Mont Belvieu Ethane	3,096	$ 0.29
Fixed-price—Mont Belvieu Propane	493	$ 1.19
Fixed-price—Mont Belvieu Iso Butane	548	$ 1.38
Fixed-price—Mont Belvieu Normal Butane	301	$ 1.38
Fixed-price—Mont Belvieu Natural Gasoline	1,438	$ 2.06

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 an obligation, which expires in November 2014, to 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. However, the price received is based on a Northeast

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index and was less than the index price in the Rockies in 2013. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation.

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, oil and natural gas liquids development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. Our development and production techniques specialize in production from tight-sands and shale formations as well as coal bed methane reserves in the Piceance, Williston, San Juan, Powder River, Appalachian and Green River Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management 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, an oil and gas exploration and production company with activities primarily in Argentina and Colombia.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges for accounting purposes. Most of our commodity derivative contracts entered into after 2011 continue to serve as economic hedges but are not 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. The unrealized changes in fair value of cash flow hedge derivatives recorded in accumulated other comprehensive income at December 31, 2012 were realized at the end of first quarter 2013.

2013 vs. 2012

Revenue Analysis

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2013	2012		
	(Millions)			
Domestic revenues:				
Natural gas sales	$1,074	$1,346	$(272)	(20)%
Oil and condensate sales	534	376	158	42%
Natural gas liquid sales	228	296	(68)	(23)%
Total product revenues	1,836	2,018	(182)	(9)%
Gas management	891	949	(58)	(6)%
Net gain (loss) on derivatives not designated as hedges	(124)	78	(202)	NM
Other	6	7	(1)	(14)%
Total domestic revenues	$2,609	$3,052	$(443)	(15)%
Total international revenues	152	$137	$15	11%
Total revenues	$2,761	$3,189	$(428)	(13)%

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 the respective line items of domestic revenues are comprised of the following:

- $272 million decrease in natural gas sales primarily due to the absence of $423 million of realized gains in 2012 from derivatives designated as hedges and $90 million related to lower production sales volumes offset by $218 million related to higher sales prices (excluding hedges). The Company no longer designated derivatives entered into after December 31, 2011 as hedges for accounting purposes. The decrease in our production sales volumes is due in part to our disciplined development of natural gas reserves in a low natural gas price environment. However, natural gas production in the Appalachian Basin has increased over prior year but third party infrastructure constraints are continuing. We also have increased drilling in the Piceance Basin that will increase production from current levels in that basin. Natural gas production from the Piceance Basin represents approximately 60 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for 2013 and 2012:

	Years ended December 31,	
	2013	2012
Natural gas sales excluding all derivative settlements (per Mcf)	$ 2.97	$ 2.32
Impact of hedges (per Mcf)	0.02	1.06
Natural gas sales including hedges (per Mcf)	$ 2.99	$ 3.38
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)(a)	(0.06)	0.03
Natural gas net price including all derivative settlements (per Mcf)	$ 2.93	$ 3.41
Natural gas production sales volumes (MMcf)	359,463	397,483

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $158 million increase in oil and condensate sales reflects increased production sales volumes as well as a higher price per barrel (including the impact of hedges in 2012) for 2013 compared to 2012. The increase in production sales volumes primarily relates to increased production in the Williston Basin where the per day volumes were 13.2 MBbls per day for 2013 compared to 9.5 MBbls per day for 2012. The San Juan Basin also had production of 0.8 MBbls per day for 2013. The following table reflects oil and condensate production prices and volumes for 2013 and 2012:

	Years ended December 31,	
	2013	2012
Oil sales excluding all derivative settlements (per barrel)	$ 90.21	$ 83.35
Impact of hedges (per barrel)	$ —	$ 2.23
Oil sales including hedges (per barrel)	$ 90.21	$ 85.58
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)(a)	$ 1.52	$ 0.35
Oil net price including all derivative settlements (per barrel)	$ 91.73	$ 85.93
Oil and condensate production sales volumes (MBbls)	5,928	4,394

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $68 million decrease in natural gas liquids sales reflects decreased production sales volumes for 2013 compared to 2012, a portion of which relates to lower ethane recovery rates as a result of ethane prices in the Piceance Basin during 2013. The increased average per barrel price for natural gas liquids reflects a change in the composition of the barrel, as noted in the table below, due to lower ethane recovery rates. The following table reflects NGL production prices and volumes for 2013 and 2012:

	Years ended December 31,	
	2013	2012
NGL sales excluding all derivative settlements (per barrel)	$ 30.70	$ 28.56
Impact of hedges (per barrel)	$ —	$ —
NGL sales including hedges (per barrel)	$ 30.70	$ 28.56
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)(a)	$ 0.07	$ 1.56
NGL net price including all derivative settlements (per barrel)	30.77	30.12
NGL production sales volumes (MBbls)	7,421	10,392

(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

The following table summarizes the composition of the Piceance NGL barrel for 2013 and 2012:

	Years ended December 31,					
	2013			2012		
	% of barrel		$/gallon	% of barrel		$/gallon
Ethane	39	%	$0.25	56	%	$0.41
Propane	29	%	$0.98	21	%	$1.00
Iso-Butane	8	%	$1.41	6	%	$1.80
Normal Butane	7	%	$1.38	5	%	$1.65
Natural Gasoline	17	%	$2.11	12	%	$2.14

- $58 million decrease in gas management revenues is primarily due to lower commodity sales volumes partially offset by an increase in average prices on physical natural gas sales. We experienced a similar decrease of $65 million in related gas management costs and expenses.
- $202 million change in net gain (loss) on derivatives not designated as hedges reflects both unrealized and realized losses on derivatives for 2013. The change in the unrealized loss for 2013 primarily relates to crude and natural gas derivatives as well as natural gas transportation hedges. The net change in the realized loss in 2013 primarily related to natural gas and NGL derivatives.

International Revenues

International revenues increased primarily due to the reinstatement of a government hydrocarbon subsidy program in Argentina in 2013.

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

	Years ended December 31, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$271	$251	$(20)	(8)%
Gathering, processing and transportation	430	504	74	15%
Taxes other than income	117	87	(30)	(34)%
Gas management, including charges for unutilized pipeline capacity	931	996	65	7%
Exploration	424	72	(352)	NM
Depreciation, depletion and amortization	906	939	33	4%
Impairment of producing properties and costs of acquired unproved reserves	1,052	225	(827)	NM
Gain on sale of Powder River Basin deep rights leasehold	(36)	—	36	NM
General and administrative	275	273	(2)	(1)%
Other—net	17	12	(5)	(42)%
Total domestic costs and expenses	$4,387	$3,359	$(1,028)	(31)%
International costs and expenses:				
Lease and facility operating	$37	$32	$(5)	(16)%
Gathering, processing and transportation	3	2	(1)	(50)%
Taxes other than income	24	24	—	—%
Exploration	7	11	4	36%
Depreciation, depletion and amortization	34	27	(7)	(26)%
Impairment of producing properties and costs of acquired unproved reserves	3	—	(3)	NM
General and administrative	14	14	—	—%
Other—net	—	—	—	NM
Total international costs and expenses	$122	$110	$(12)	(11)%
Total costs and expenses	$4,509	$3,469	$(1,040)	(30)%
Domestic operating income (loss)	$(1,778)	$(307)	$(1,471)	NM
International operating income (loss)	$30	$27	$3	11%

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

Significant components on our domestic costs and expenses are comprised of the following:

- $20 million increase in lease and facility operating expense primarily relates to increased water disposal costs due in part to decreased drilling in the Appalachian Basin and the corresponding utilization of produced water in the well hydraulic fracturing process. Additionally, increased Williston Basin production in relation to our overall portfolio impacted the increase in lease and facility operating expense. Lease and facility operating expense averaged $0.62 per Mcfe for 2013 compared to $0.52 per Mcfe in 2012.
- $74 million decrease in gathering, processing and transportation charges primarily related to new favorable contract terms for gathering and processing services in the Piceance Basin as well as lower volumes. Gathering, processing and transportation expenses averaged $0.98 per Mcfe compared to $1.04 per Mcfe for 2013 and 2012, respectively. Gathering, processing and transportation for 2012 includes a $9 million adjustment related to royalty calculations for

prior periods. Excluding this adjustment, gathering, processing and transportation expenses would have averaged $1.02 per Mcfe for 2012.

- $30 million increase in taxes other than income from 2013 compared to 2012 relates to the increase in natural gas prices (excluding derivatives), increased crude oil production volumes and higher crude oil prices. Taxes other than income averaged $0.27 per Mcfe for 2013 compared to $0.18 per Mcfe for 2012.
- $65 million decrease in gas management expenses reflect the lower commodity purchase volumes partially offset by an increase in average prices on physical natural gas cost of sales. Also included in gas management expenses are $61 million and $46 million for 2013 and 2012, respectively, for unutilized pipeline capacity. Gas management expenses for the period ended December 31, 2013 and 2012 included $1 million and $11 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage and 2013 includes $9 million related to the buyout of a transportation agreement.
- $352 million higher exploration expense primarily relates to a $317 million impairment to fair value of leasehold in the Appalachian Basin in 2013 as well as higher leasehold amortization expense.
- $33 million decrease in depreciation, depletion and amortization primarily due to lower production volumes in 2013 compared to 2012. Also during 2013, we have adjusted our proved reserves used for the calculation of depletion and amortization which resulted in a net $17 million reduction of depreciation, depletion and amortization expense for 2013. These adjustments primarily reflect the impact of an increase in the 12 month average price partially offset by reduced NGL reserves due to continued lower ethane recovery. During 2013 our depreciation, depletion and amortization averaged $2.06 per Mcfe compared to an average $1.93 per Mcfe in 2012. This increase partially reflects the growth of the Williston Basin as part of our portfolio.
- $1,052 million in 2013 of impairments of producing properties and cost of acquired unproved reserves compared to $225 million for 2012, as previously discussed. (See Note 6 of Notes to Consolidated Financial Statements.)
- $36 million gain on the sale of Powder River Basin deep rights leasehold in 2013.
- General and administrative expense was relatively flat compared to 2012. Additionally, 2013 includes $4 million of costs associated with the separation of our chief executive officer. General and administrative expense averaged $0.62 per Mcfe compared to $0.56 per Mcfe for 2013 and 2012, respectively.
- Other expenses for 2013 includes approximately $8 million for settlement of litigation. Rig release and standby fees were $12 million and $9 million for 2013 and 2012, respectively.

International costs

International costs increased primarily due to higher depreciation, depletion and amortization and higher production and lifting costs. Additionally, a $3 million impairment for property in Colombia was recorded in 2013.

Consolidated results below operating income (loss)

	Years ended December 31, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$(1,748)	$(280)	$(1,468)	NM
Interest expense	(108)	(102)	(6)	(6)%
Interest capitalized	5	8	(3)	(38)%
Investment income, impairment of equity method investment and other	5	30	(25)	(83)%
Loss from continuing operations before income taxes	(1,846)	(344)	(1,502)	NM
Benefit for income taxes	(655)	(111)	(544)	NM
Income (loss) from continuing operations	(1,191)	(233)	(958)	NM
Income (loss) from discontinued operations	—	22	(22)	(100)%
Net income (loss)	(1,191)	(211)	(980)	NM
Less: Net income attributable to noncontrolling interests	(6)	12	(18)	(150)%
Net income (loss) attributable to WPX Energy, Inc.	$(1,185)	$(223)	$(962)	NM

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

The increase in interest expense primarily relates to a higher amount outstanding on our revolver in 2013.

Our investment income and other primarily reflects equity earnings associated with our international and domestic equity method investments. In addition, 2013 includes a $20 million impairment related to an equity method investment in the Appalachian Basin. This impairment was a result of the 2013 impairment of the producing properties in the Appalachian Basin (see Notes 4 and 6 of Notes to Consolidated Financial Statements).

Benefit for income taxes changed favorably primarily due to greater pre-tax loss for 2013 compared to 2012. Income taxes in 2013 include a $80 million deferred tax provision related to the increase in a valuation allowance on certain state deferred tax assets. Income taxes in 2013 also included a $10 million provision related to the impact of the new capital tax law in Argentina. In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of our consolidated investment in Apco, a Cayman Islands corporation. The new 10 percent dividend tax will be accrued by Apco when dividends are paid by its Argentine investments in future periods. The capital gains tax applies to the sale of Argentine securities by a non Argentine resident, such as Apco, making such sales subject to an effective 13.5 percent tax on the gross proceeds. As a result, Apco recorded approximately $14 million of a foreign deferred tax expense during third quarter 2013 for the excess book basis over tax basis in its equity investment in Petrolera Entre Lomas S.A., of which approximately $12 million relates to basis differences that occurred prior to 2013. This accrual was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX related to the additional Argentine tax. See Note 10 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income from discontinued operations for 2012 reflects a $38 million pretax gain on sale in 2012.

The change in net income (loss) attributable to noncontrolling interests is primarily due to $11 million associated with the impairment of a certain Appalachian Basin facility asset as well as a $4 million impact in 2013 as a result of the new Argentine tax law.

2012 vs. 2011

Revenue Analysis

	Years ended December 31,		Favorable (Unfavorable)	Favorable (Unfavorable) %
	2012	2011	$ Change	Change
	(Millions)			
Domestic revenues:				
Natural gas sales	$1,346	$1,678	$(332)	(20)%
Oil and condensate sales	376	226	150	66%
Natural gas liquid sales	296	404	(108)	(27)%
Total product revenues	2,018	2,308	(290)	(13)%
Gas management	949	1,428	(479)	(34)%
Net gain (loss) on derivatives not designated as hedges	78	29	49	169%
Other	7	7	—	—
Total domestic revenues	$3,052	$3,772	$(720)	(19)%
Total international revenues	$137	$110	$27	25%
Total revenues	$3,189	$3,882	$(693)	(18)%

Domestic Revenues

Significant variances in the respective line items of domestic revenues are comprised of the following:

- $332 million decrease in natural gas sales primarily reflects lower gas prices (including hedges) for 2012 compared to 2011. The following table reflects natural gas production prices and volumes for 2012 and 2011:

	Years ended December 31, 2012	2011
Natural gas sales excluding all derivative settlements (per Mcf)	$ 2.32	$ 3.48
Impact of hedges (per Mcf)	1.06	0.84
Natural gas sales including hedges (per Mcf)	$ 3.38	$ 4.32
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)(a)	0.03	—
Natural gas net price including all derivative settlements (per Mcf)	$ 3.41	$ 4.32
Natural gas production sales volumes (MMcf)	397,483	388,780

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $150 million increase in oil and condensate sales reflects increased production sales volumes for 2012 compared to 2011. The following table reflects oil and condensate production prices and volumes for 2012 and 2011:

	Years ended December 31, 2012	2011
Oil sales excluding all derivative settlements (per barrel)	$ 83.35	$ 84.91
Impact of hedges (per barrel)	$ 2.23	$ 0.39
Oil sales including hedges (per barrel)	$ 85.58	$ 85.30
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)(a)	$ 0.35	$ —
Oil net price including all derivative settlements (per barrel)	$ 85.93	$ 85.30
Oil and condensate production sales volumes (MBbls)	4,394	2,651

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $108 million decrease in natural gas liquids sales reflects lower NGL prices for 2012 compared to 2011. The following table reflects natural gas liquid production prices and volumes for 2012 and 2011:

	Years ended December 31, 2012	2011
NGL sales excluding all derivative settlements (per barrel)	$ 28.56	$ 40.17
Impact of hedges (per barrel)	$ —	$ —
NGL sales including hedges (per barrel)	$ 28.56	$ 40.17
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)(a)	$ 1.56	$ —
NGL net price including all derivative settlements (per barrel)	$ 30.12	$ 40.17
NGL production sales volumes (MBbls)	10,392	10,057

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $479 million decrease in gas management revenues due to a 27 percent decrease in average prices on physical natural gas sales and 9 percent lower natural gas sales volumes. We experienced a similar decrease of $475 million in related gas management costs and expenses.
- $49 million change in net gain (loss) on derivatives not designated as hedges primarily relates to unrealized and realized mark-to-market gains on crude oil and natural gas derivatives not designated as hedges.

International Revenues

International revenues increased primarily due to increased oil sales due to higher average oil sales prices and new oil production in Colombia for 2012 compared to 2011.

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

	Years ended December 31, 2012	2011	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$251	$235	$(16)	(7)%
Gathering, processing and transportation	504	487	(17)	(3)%
Taxes other than income	87	113	26	23%
Gas management, including charges for unutilized pipeline capacity	996	1,471	475	32%
Exploration	72	123	51	41%
Depreciation, depletion and amortization	939	880	(59)	(7)%
Impairment of producing properties and costs of acquired unproved reserves	225	367	142	39%
General and administrative	273	263	(10)	(4)%
Other—net	12	(3)	(15)	NM
Total domestic costs and expenses	$3,359	$3,936	$577	15%
International costs and expenses:				
Lease and facility operating	$32	$27	$(5)	(19)%
Gathering, processing and transportation	2	—	(2)	NM
Taxes other than income	24	21	(3)	(14)%
Exploration	11	3	(8)	NM
Depreciation, depletion and amortization	27	22	(5)	(23)%
General and administrative	14	12	(2)	(17)%
Other—net	—	3	3	1%
Total international costs and expenses	$110	$88	$(22)	(25)%
Total costs and expenses	$3,469	$4,024	$555	14%
Domestic operating income (loss)	$(307)	$(164)	$(143)	(87)%
International operating income (loss)	$27	$22	$5	23%

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

Significant components on our domestic costs and expenses are comprised of the following:

- Lease and facility operating expense in 2012 averaged $0.52 per Mcfe compared to $0.51 per Mcfe during 2011.
- $17 million increase in gathering, processing and transportation expenses primarily as a result of an increase in natural gas liquids volumes. This increase includes a $9 million adjustment related to royalty calculations for prior periods. Excluding this adjustment, our gathering, processing and transportation charges averaged $1.02 per Mcfe for 2012 compared to an average of $1.05 for 2011.

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- $26 million decrease in taxes other than income for 2012 primarily reflecting the impact of decreased total product revenues (excluding hedges) resulting from lower commodity prices in 2012 compared to 2011. Our taxes other than income averaged $0.18 per Mcfe for 2012 compared to an average of $0.24 for 2011.
- $475 million decrease in gas management expenses due to a 27 percent decrease in average prices on physical natural gas cost of sales and a 9 percent decrease in natural gas sales volumes. Also included in gas management expenses are $46 million and $35 million in 2012 and 2011, respectively, for unutilized pipeline capacity. Gas management expenses in 2012 and 2011 also include $11 million and $10 million, respectively, related to lower of cost or market charges to the carrying value of natural gas inventories in storage.
- $51 million decrease in exploration expenses primarily reflects lower unproved leasehold impairment, amortization and expiration expenses in 2012 compared to 2011 which includes a $50 million write-off impairment of acreage in Columbia County, Pennsylvania that we no longer planned to develop. Additionally, in 2011 we incurred approximately $11 million of dry hole expenses in connection with a Marcellus Shale well in Columbia County because results were inconclusive and raised substantial doubt about the economic and operational viability of the well.
- $59 million increase in depreciation, depletion and amortization expenses which reflects higher production volumes and a slightly higher rate. During 2012 our depreciation, depletion and amortization averaged $1.93 per Mcfe compared to an average $1.89 per Mcfe in 2011. During the course of 2012, we adjusted our estimated proved reserves used for the calculation of depletion and amortization to reflect the impact of the decrease in the 12 month average price; this resulted in a total of approximately $31 million additional depreciation, depletion and amortization expense in 2012 and was the main driver of the increase in the average per Mcfe.
- $225 million of property impairments in 2012 compared to $367 million in 2011, as previously discussed.
- The increase in other-net expense for 2012 primarily reflects $9 million in rig release penalties and rig standby fees.

International costs

International costs increased primarily due to higher exploration expenses related to 3-D seismic acquisition costs and dry hole expenses. Costs also increased due to higher depreciation, depletion and amortization and higher production and lifting costs.

Consolidated results below operating income (loss)

	Years ended December 31,		Favorable (Unfavorable)	Favorable (Unfavorable) %
	2012	2011	$ Change	Change
	(Millions)			
Consolidated operating income (loss)	$(280)	$(142)	$(138)	(97)%
Interest expense	(102)	(117)	15	13%
Interest capitalized	8	9	(1)	(11)%
Investment income	30	26	4	15%
Loss from continuing operations before income taxes	(344)	(224)	(120)	(54)%
Benefit for income taxes	(111)	(74)	37	50%
Income (loss) from continuing operations	(233)	(150)	(83)	(55)%
Income (loss) from discontinued operations	22	(142)	164	NM
Net income (loss)	(211)	(292)	81	28%
Less: Net income attributable to noncontrolling interests	12	10	2	20%
Net income (loss) attributable to WPX Energy, Inc.	$(223)	$(302)	$79	26%

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 in 2012 primarily reflects interest accrued on our senior notes issued in November 2011. Interest expense in 2011 primarily reflects interest through June 30, 2011 associated with our unsecured notes payable with Williams. The outstanding amounts were cancelled by Williams and contributed to capital on June 30, 2011.

Additionally, interest expense in 2011 also includes $11 million of interest on our senior notes issued in November 2011.

Our investment income and other primarily reflects equity earnings associated with our international and domestic equity method investments.

The benefit for income taxes increased in 2012 from 2011 due to an increased loss from continuing operations. See Note 10 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations reflects a $38 million pretax gain on sale in 2012 and a $209 million pretax impairment in 2011. As previously discussed, we completed the sale of our holdings in Barnett Shale and the Arkoma Basin during 2012. See Note 2 of Notes to Consolidated Financial Statements.

Management’s Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

In 2013 we continued to focus upon growth through continued disciplined investments in expanding our natural gas, oil and NGL portfolio.

Our main sources of liquidity are cash on hand, internally generated cash flow from operations and our bank 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. Prior to December 1, 2011, our liquidity was 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 canceled by Williams. Any cash activity from 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 senior notes. In consideration of our liquidity, we note the following:

- As of December 31, 2013, 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 and cash on hand. Included in our cash and cash equivalents at December 31, 2013 is $51 million related to our international 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. Our primary sources of liquidity in 2014 are expected cash flows from operations, proceeds from monetization of assets, including the potential formation of an MLP, and additional borrowings on our $1.5 billion credit facility. The combination of these sources should be sufficient to allow us to pursue our business strategy and goals for 2014.

We note the following assumptions for 2014:

- Our capital expenditures, including international, are estimated to be up to $1.5 billion in 2014 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 cash on hand.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;
- Lower than expected proceeds from asset sales;
- 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 leaseholds; and
- Reduced access to our credit facility.

Under the credit facility agreement ("Credit Facility Agreement") and prior to our receipt of an investment grade rating with a stable outlook, we are required to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness (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 are adjusted to reflect the impact of hedges, our lenders' commodity price forecasts, and, if necessary, to include only a portion of our reserves that are not proved developed producing reserves). See Note 9 of Notes to Consolidated Financial Statements. We are in the process of completing the net present value calculation due by April 20, 2014, however, we believe that we will have full access to the $1.5 billion in 2014. Further declines in natural gas prices during future years could reduce our net present value and thus limit our available capacity under the agreement.

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 to 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 Agreement. At December 31, 2013, a total of $361 million in letters of credit have been issued.

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(a)	
Corporate Credit Rating	BB+
Senior Unsecured Debt Rating	BB+
Outlook	Stable
Moody's Investors Service(b)	
Senior Unsecured Debt Rating	Ba1
LT Corporate Family Rating	Ba1
Outlook	Stable

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(a) 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.

(b) 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.

Sources (Uses) of Cash

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Net cash provided (used) by:			
Operating activities	$636	$796	$1,207
Investing activities	(1,111)	(1,204)	(1,556)
Financing activities	426	37	839
Increase (decrease) in cash and cash equivalents	$(49)	$(371)	$490

Operating activities

Our net cash provided by operating activities in 2013 decreased from 2012 primarily due to the decrease in our operating results driven by lower natural gas (including the impact of hedges) and NGL sales revenues.

The decrease in net cash provided by operating activities in 2012 from 2011 is primarily due to lower realized commodity prices.

Investing activities

Significant items include expenditures for drilling and completion of approximately $1.0 billion, $1.2 billion and $1.4 billion in 2013, 2012 and 2011, respectively. Also included, are proceeds of $36 million from the sale of deep rights in the Powder River Basin in 2013 and $306 million from the sale of our holdings in the Barnett Shale and Arkoma Basin in 2012.

Financing activities

Net cash provided by financing activities in 2013 includes $410 million net borrowings on our credit facility.

Net cash provided by financing activities in 2012 includes $10 million of a contribution from a third party related to the formation of a consolidated limited liability company. This company was formed to hold gathering facilities.

Net cash provided by financing activities in 2011 includes $1.5 billion Note proceeds in November 2011 and $159 million in borrowings from Williams prior to July 2011. Partially offsetting these proceeds was a $981 million distribution to Williams in November 2011.

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, 2013 and December 31, 2012.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2013.

	2014	2015 – 2016	2017 – 2018	Thereafter	Total
	(Millions)				
Long-term debt, including current portion:					
Principal	$3	$416	$400	$1,100	$1,919
Interest	96	191	143	231	661
Operating leases and associated service commitments:					
Drilling rig commitments(a)	108	111	—	—	219
Other	15	18	15	22	70
Transportation and storage commitments(b)	224	416	345	578	1,563
Natural gas purchase commitments(c)	3	—	—	—	3
Oil and gas activities(d)	123	145	105	114	487
Other	16	16	—	—	32
Other long-term liabilities, including current portion:					
Physical and financial derivatives(e)	383	530	512	1,240	2,665
Total	$971	$1,843	$1,520	$3,285	$7,619

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

(b) Excludes additional commitments totaling $58 million associated with projects for which the counterparty has not yet received satisfactory regulatory approvals or, for other business reasons, has not yet begun construction.

(c) 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, 2013 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. In 2013, certain parties converted their gas purchase agreements to firm gathering and processing agreements, which services will be provided by Williams Partners. WPX Energy's gas purchase obligations totaling $1.2 billion at December 31, 2012 terminated at the effective date of the new agreements.

(d) Includes gathering, processing and other oil and gas related services commitments. Excluded are liabilities associated with asset retirement obligations, which total $364 million as of December 31, 2013. The ultimate settlement and timing cannot be precisely determined in advance; however, we estimate that approximately 6 percent of this liability will be settled in the next five years.

(e) Includes $2.6 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, 2013, 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.

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.

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, 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 and natural gas liquids forward prices during 2013 and more significantly in the fourth quarter, 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 reserves quantities, estimates of future commodity prices (primarily natural gas, 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 $1,055 million of impairment charges in 2013. See Notes 6 and 15 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 64 percent could be at risk for impairment if forward natural gas and NGL prices across all future periods decline by approximately 6 percent to 8 percent, on average, as compared to the forward commodity prices at December 31, 2013. We estimate that

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approximately 28 percent could be at risk for impairment if forward oil prices across all periods decline by approximately 11 percent to 13 percent.

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, new commodity derivative contracts that serve as economic hedges of production 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 derivative instruments, hereafter referred to as economic hedges or derivatives not designated as 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. The unrealized changes in fair value of cash flow hedge derivatives recorded in accumulated other comprehensive income at December 31, 2012 were realized at the end of the first-quarter 2013.

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 13 months. We further assess the appropriate accounting method for any derivatives identified, which could include:

- applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings;
- qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or
- 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 for derivatives entered into prior to 2012.

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 included 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 assessed whether the hedged forecasted transaction is probable of occurring. This assessment required 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 compared 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 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.

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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 Statements of Operations		Consolidated Balance Sheets	
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 16 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 natural gas, oil and NGL reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates; and
- Changes in natural gas, oil and NGL reserves and forward market prices both impact projected future cash flows from our 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, over 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 $80 million and $98 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.

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. Additionally, our leasehold costs are evaluated for impairment if the proved property costs in the basin are impaired. Our capitalized lease acquisition costs, including costs of acquired unproved reserves, totaled $382 million at December 31, 2013.

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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 11 of Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Liabilities

We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years. Included in our deferred taxes are 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 deferred tax assets and establish a valuation allowance for those that do not meet the more likely than not threshold. When assessing the need for a valuation allowance, we consider future reversals of existing taxable temporary differences, future taxable income exclusive of reversing temporary differences and carryforwards, and tax-planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryforwards. 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.

The determination of our state deferred tax requires judgment as we did not exist as a stand-alone filer in all states prior to the spin-off and the state deferred tax can change periodically based on changes in our operations. Our state deferred tax is based upon our current entity structure and the jurisdictions in which we operate.

See Note 10 of Notes to Consolidated 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. 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, 2013, 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, 2013, 92 percent of the fair value of our derivatives portfolio expires in the next 12 months and more than 99 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, 2013, 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, 2013, 2012 and 2011, 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

Our interest rate risk exposure is related primarily to our debt portfolio. Our senior notes are fixed rate debt in order to mitigate the impact of fluctuations in interest rates. For our fixed rate debt, $400 million matures in 2017 and $1,100 million matures in 2022. Interest rates for each group are 5.25 percent and 6.00 percent, respectively. The aggregate fair value of the senior notes is $1,528 million. Borrowings under our credit facility are based on a variable interest rate and could expose us to the risk of increasing interest rates. As of December 31, 2013, the weighted average variable interest rate was 2.27 percent on the $410 million outstanding under the Credit Facility Agreement. See Note 9 of Notes to Consolidated Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, oil and NGLs, 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 Notes 15 and 16 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 $1 million at December 31, 2013 and a net asset of $1 million at December 31, 2012. The value at risk for contracts held for trading purposes was less than $1 million at December 31, 2013 and December 31, 2012.

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 liability of $64 million at December 31, 2013 and a net asset of $39 million at December 31, 2012.

The value at risk for derivative contracts held for nontrading purposes was $19 million at December 31, 2013, and $6 million at December 31, 2012. During the year ended December 31, 2013, our value at risk for these contracts ranged from a high of $19 million to a low of $12 million. The increase in value at risk from December 31, 2012 primarily reflects new derivative contracts entered into to hedge our equity production.

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Item 8. Financial Statements and Supplementary Data

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a—15(f) and 15d—15(f) under the Securities Exchange Act of 1934). Our internal controls over financial reporting are designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and Board of Directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2013, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (1992). Based on our assessment, we concluded that, as of December 31, 2013, our internal control over financial reporting was effective.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm on
Internal Control over Financial Reporting

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

We have audited WPX Energy, Inc. internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). WPX Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, WPX Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of WPX Energy, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2013, of WPX Energy, Inc. and our report dated February 27, 2014, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 27, 2014

Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders of WPX Energy, Inc.
We have audited the accompanying consolidated balance sheets of WPX Energy, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15.(a). These financial statements and schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.
In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of WPX Energy, Inc. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), WPX Energy, Inc.’s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 27, 2014, expressed an unqualified opinion thereon.
/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 27, 2014

WPX Energy, Inc.
Consolidated Balance Sheets

	December 31, 2013 (Millions)	2012
Assets		
Current assets:		
Cash and cash equivalents	$99	$153
Accounts receivable, net of allowance of $7 and $11 as of December 31, 2013 and 2012, respectively	536	443
Deferred income taxes	49	17
Derivative assets	50	58
Inventories	72	66
Margin deposits	71	—
Other	45	35
Total current assets	922	772
Investments	145	145
Properties and equipment, net (successful efforts method of accounting)	7,241	8,416
Derivative assets	7	2
Other noncurrent assets	114	121
Total assets	$8,429	$9,456
Liabilities and Equity		
Current liabilities:		
Accounts payable	652	509
Accrued and other current liabilities	190	201
Customer margin deposits payable	55	2
Derivative liabilities	110	14
Total current liabilities	1,007	726
Deferred income taxes	788	1,401
Long-term debt	1,916	1,508
Derivative liabilities	12	1
Asset retirement obligations	358	316
Other noncurrent liabilities	138	133
Contingent liabilities and commitments (Note 11)		
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; 201 million shares issued at December 31, 2013 and 199.3 million shares issued at December 31, 2012)	2	2
Additional paid-in-capital	5,516	5,487
Accumulated deficit	(1,408)	(223)
Accumulated other comprehensive income (loss)	(1)	2
Total stockholders' equity	4,109	5,268
Noncontrolling interests in consolidated subsidiaries	101	103
Total equity	4,210	5,371
Total liabilities and equity	$8,429	$9,456

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Operations

	Years Ended December 31, 2013	2012	2011
	(Millions, except per share amounts)		
Revenues:			
Product revenues:			
Natural gas sales	$1,093	$1,364	$1,694
Oil and condensate sales	649	491	312
Natural gas liquid sales	230	299	408
Total product revenues	1,972	2,154	2,414
Gas management	891	949	1,428
Net gain (loss) on derivatives not designated as hedges (Note 16)	(124)	78	29
Other	22	8	11
Total revenues	2,761	3,189	3,882
Costs and expenses:			
Lease and facility operating	308	283	262
Gathering, processing and transportation	433	506	487
Taxes other than income	141	111	134
Gas management, including charges for unutilized pipeline capacity	931	996	1,471
Exploration (Note 6)	431	83	126
Depreciation, depletion and amortization	940	966	902
Impairment of producing properties and costs of acquired unproved reserves (Note 6)	1,055	225	367
Gain on sale of Powder River Basin deep rights leasehold	(36)	—	—
General and administrative	289	287	275
Other—net	17	12	—
Total costs and expenses	4,509	3,469	4,024
Operating income (loss)	(1,748)	(280)	(142)
Interest expense	(108)	(102)	(117)
Interest capitalized	5	8	9
Investment income, impairment of equity method investment and other	5	30	26
Income (loss) from continuing operations before income taxes	(1,846)	(344)	(224)
Provision (benefit) for income taxes	(655)	(111)	(74)
Income (loss) from continuing operations	(1,191)	(233)	(150)
Income (loss) from discontinued operations	—	22	(142)
Net income (loss)	(1,191)	(211)	(292)
Less: Net income (loss) attributable to noncontrolling interests	(6)	12	10
Net income (loss) attributable to WPX Energy, Inc.	$(1,185)	$(223)	$(302)
Amounts attributable to WPX Energy, Inc.:			
Basic and diluted earnings (loss) per common share (Note 5):			
Income (loss) from continuing operations	$(5.91)	$(1.23)	$(0.81)
Income (loss) from discontinued operations	—	0.11	(0.72)
Net income (loss)	$(5.91)	$(1.12)	$(1.53)
Weighted-average shares	200.5	198.8	197.1

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Net income (loss) attributable to WPX Energy, Inc.	$(1,185)	$(223)	$(302)
Other comprehensive income (loss):			
Change in fair value of cash flow hedges, net of tax(a)	$—	$57	$262
Net reclassifications into earnings of net cash flow hedge gains, net of tax(b)	(3)	(274)	(211)
Other comprehensive income (loss), net of tax	(3)	(217)	51
Comprehensive income (loss) attributable to WPX Energy, Inc.	$(1,188)	$(440)	$(251)

(a) Change in fair value of cash flow hedges is net of income tax of $33 million and $151 million for 2012 and 2011, respectively. 2012 includes a $15 million before tax unrealized gain that was recognized in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations, as the underlying transaction was no longer probable of occurring (see Note 16).

(b) Net reclassifications into earnings of net cash flow hedge realized gains are net of $2 million, $159 million and $120 million of income tax for 2013, 2012 and 2011, respectively. Before tax amounts realized and reclassified to product revenues, primarily natural gas sales revenues, on the Consolidated Statements of Operations were $5 million, $434 million and $331 million for 2013, 2012 and 2011, respectively.

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Changes in Equity

	WPX Energy, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Williams' Net Investment	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests(a)	Total
	(Dollars in millions)							
Balance at December 31, 2010	$—	$—		$ 4,244	$ 168	$ 4,412	$ 72	$4,484
Comprehensive income:								
Net income (loss)	—	—		(302)	—	(302)	10	(292)
Other comprehensive income (loss)	—	—		—	51	51	—	51
Comprehensive income (loss)								(241)
Contribution of Notes Payable to Williams (Note 3)				2,420		2,420		2,420
Allocation of alternative minimum tax credit (Note 10)				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
Comprehensive income:								
Net income (loss)	—	—	(223)	—	—	(223)	12	(211)
Other comprehensive income (loss)	—	—		—	(217)	(217)	—	(217)
Comprehensive income (loss)								(428)
Contribution from noncontrolling interest							10	10

Stock based compensation, net of tax benefit	—	30		—	—	30	—	30
Balance at December 31, 2012	2	5,487	(223)	—	2	5,268	103	5,371
Comprehensive income:								
Net income (loss)	—	—	(1,185)			(1,185)	(6)	(1,191)
Other comprehensive income (loss)	—	—			(3)	(3)		(3)
Comprehensive income (loss)								(1,194)
Contribution from noncontrolling interest	—	—		—	—	—	4	4
Stock based compensation, net of tax benefit	—	29		—	—	29	—	29
Balance at December 31, 2013	$2	$5,516	$(1,408)	$—	$(1)	$4,109	$101	$4,210

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(a) Primarily represents the 31 percent of Apco Oil and Gas International Inc. owned by others.
See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2013	2012	2011
Operating Activities	(Millions)		
Net income (loss)	$(1,191)	$(211)	$(292)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	940	973	951
Deferred income tax provision (benefit)	(645)	(160)	(176)
Provision for impairment of properties and equipment (including certain exploration expenses) and investments	1,483	288	694
Amortization of stock-based awards	32	28	5
Gain on sales of assets (a)	(41)	(42)	(1)
Cash provided (used) by operating assets and liabilities:			
Accounts receivable	(43)	68	(100)
Inventories	(5)	7	3
Margin deposits and customer margin deposit payable	(18)	(5)	(18)
Other current assets	(7)	7	(11)
Accounts payable	41	(128)	131
Accrued and other current liabilities	(21)	12	10
Changes in current and noncurrent derivative assets and liabilities	106	(32)	8
Other, including changes in other noncurrent assets and liabilities	5	(9)	3
Net cash provided by operating activities	636	796	1,207
Investing Activities			
Capital expenditures (b)	(1,154)	(1,521)	(1,572)
Proceeds from sales of assets	49	310	15
Purchases of investments	(3)	(2)	(12)
Other	(3)	9	13
Net cash used in investing activities	(1,111)	(1,204)	(1,556)
Financing Activities			
Proceeds from common stock	6	3	—
Proceeds from long-term debt	—	6	1,502
Borrowings on credit facility	970	50	—
Payments on credit facility	(560)	(50)	—
Contribution from noncontrolling interest	4	10	—
Excess tax benefit of stock based awards	—	13	—
Payments for debt issuance costs	—	—	(30)
Net increase in notes payable to Williams	—	—	159
Net changes in Williams' net investment	—	—	(777)
Other	6	5	(15)
Net cash provided by financing activities	426	37	839
Net increase (decrease) in cash and cash equivalents	(49)	(371)	490
Effect of exchange rate changes on cash and cash equivalents	(5)	(2)	(1)
Cash and cash equivalents at beginning of period	153	526	37
Cash and cash equivalents at end of period	$99	$153	$526

(a) 2013 includes a $36 million gain on sale of Powder River Basin deep rights leasehold (Note 6) and 2012 includes the gain on the sale of Barnett Shale and Arkoma Basin (Note 2).

(b) Increase to properties and equipment	$(1,207)	$(1,449)	$(1,641)
Changes in related accounts payable and accounts receivable	53	(72)	69
Capital expenditures	$(1,154)	$(1,521)	$(1,572)

See accompanying notes.

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. WPX Energy, Inc. was formed in 2011 by The Williams Companies, Inc. (“Williams”) to effect the separation of its exploration and production business. Williams contributed to the Company its investment in certain subsidiaries related to Williams’ domestic and international exploration and production businesses, collectively referred to as the “Contribution”. The separation was completed on December 31, 2011 through a pro rata distribution of WPX common stock to Williams’ stockholders.
Domestic includes natural gas, oil and NGL development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. We specialize in development and production from tight-sands and shale formations and coal bed methane reserves in the Piceance, Williston, San Juan, Powder River, Appalachian and Green River Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management 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 activities in Argentina and Colombia.
The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as “WPX” or the “Company” is at times referred to in the first person as “we”, “us” or “our”.
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. Management believes the assumptions underlying the financial statements are reasonable. The financial statements of 2011 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 2011. 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 Williams’ net investment in excess of the par value of our common stock as additional paid-in capital. Transactions in 2011 with Williams’ other operating businesses, which generally settled monthly, are shown as changes in accounts receivable or accounts payable in the Consolidated Statements of Cash Flows for the year ended December 31, 2011. Other transactions during the period prior to separation between the Company and Williams which were not part of the notes payable to Williams have been identified in the Consolidated Statements of Equity as net transfers with Williams (see Note 3).
Discontinued operations
During the second quarter of 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. We have reported the results of operations and financial position of the Barnett Shale and Arkoma Basin operations as discontinued operations for all periods presented.
Additionally, see Note 11 for a discussion of contingencies related to Williams’ former power business (most of which was disposed in 2007).
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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

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;
- Valuations of derivatives;
- Estimation of natural gas and oil reserves;
- Assessments of litigation-related contingencies; and
- Asset retirement obligations.

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 operations consists of approximately $21 million and $19 million at December 31, 2013 and 2012, respectively, primarily related to escrow accounts established as part of the settlement agreement with certain California utilities and is included in other current and 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 11). Additionally, restricted cash of our international segment consists of approximately $6 million and $9 million at December 31, 2013 and 2012, respectively, associated with various letters of credit that is also classified in other current and 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 $49 million and $42 million at December 3l, 2013 and 2012, respectively. Additionally, we have natural gas in storage related to our gas management activities of $13 million and $24 million at December 31, 2013 and 2012, respectively, and crude oil production in transit of $10 million at December 31, 2013. 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 $1 million, $11 million and $10 million in 2013, 2012 and 2011, respectively.
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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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 Statements 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 for our domestic properties or on a 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 operating income (loss) as either a separate line item, if individually significant, or included in other—net.

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.

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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

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.

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 Statements 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 those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheets in derivative assets and derivative liabilities as 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 commodity derivatives entered into prior to January 1, 2012, we 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 established hedging relationships pursuant to our risk management policies. We evaluated 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

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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 Statements 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.

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, oil and condensate and natural gas liquids 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, 2013 and 2012 was insignificant. Additionally, natural gas revenues include $5 million, $423 million and $326 million in 2013, 2012 and 2011, respectively, of realized gains from derivatives designated as cash flow hedges of our production sold.

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 through May 2012 included purchases and subsequent sales to Williams Partners for fuel and shrink gas (see Note 3). 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, oil and NGLs 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 $61 million, $46 million and $35 million in 2013, 2012 and 2011, respectively.

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 3). We did not capitalize interest for the period from July 1, 2011 to mid November 2011. Beginning November 2011, we began using the weighted average rate of our long-term notes payable which were issued in November 2011 (see Note 9).

Income taxes

We file consolidated and combined federal and state income tax returns for the Company and its subsidiaries. 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 provisions for 2011 were calculated on a separate return basis for us and our subsidiaries, except for certain adjustments. We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years.

Employee stock-based compensation

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 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.

Through the date of the 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.

Through the date of the 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.

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 (see Note 5).

Note 2. Discontinued Operations

During the first quarter of 2012, our management signed an agreement to divest its holdings in the Barnett Shale and the Arkoma Basin. The transaction closed in second-quarter 2012. Total proceeds received from the sale were $306 million.

Summarized Results of Discontinued Operations

	2012	2011
	(Millions)	
Revenues	$28	$118
Income (loss) from discontinued operations before gain on sale, impairments and income taxes	$(3)	$(15)
Gain on sale	38	—
Impairments	—	(209)
Less: Provision (benefit) for income taxes	13	(82)
Income (loss) from discontinued operations	$22	$(142)

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

The impairments in 2011 reflect write-downs to estimates of fair value of our holdings in the Barnett Shale and the Arkoma Basin. Impairment charges on our Fort Worth (Barnett Shale) properties were $180 million in 2011. Impairment charges in Arkoma were $29 million in 2011. These nonrecurring fair value measurements, which fall within Level 3 of the fair value hierarchy, utilized a probability-weighted discounted cash flow analysis that was based on internal cash flow models.

Note 3. 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. 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 for one year following separation.

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 sponsored and maintained employee compensation and benefit programs relating to all employees who transferred to us from Williams in connection with the spin-off through the contribution of two newly established service entities that employees of Williams were moved to prior to the spin-off. 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 transferred to us or our benefit plans and our employees ceased active participation in those plans as of January 1, 2012.

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 13). 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.

Through the date of 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 Statements of Operations.

In addition, Williams charged us for certain employees of Williams who provided 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 Statements of Operations. In management's estimation, the allocation methodologies used were reasonable and resulted in a reasonable allocation to us of our costs of doing business incurred by Williams.

Other arrangements with Williams or its affiliates

We also have operating activities with Williams Partners and another Williams subsidiary. Beginning January 1, 2012, Williams and its subsidiaries were no longer related parties, therefore only amounts related to 2011 are disclosed as related parties. For 2011, the following were considered related party transactions. Our revenues include revenues from the following types of transactions:

- Sales of NGLs related to our production to Williams Partners at market prices at the time of sale and included within our oil and gas sales revenues; and
- Sales to Williams Partners 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 Williams Partners:

- 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 included commitments totaling $401 million at December 31, 2011.

We have managed a transportation capacity contract for Williams Partners. To the extent the transportation is not fully utilized or does not recover full-rate demand expense, Williams Partners reimburses us for these transportation costs. These reimbursements to us totaled approximately $11 million for the year ended December 31, 2011, and are included in gas management revenues. We signed an agreement with Williams Partners under which these contracts were assigned to them effective May 1, 2012.

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 percent at June 30, 2011.

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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Below is a summary for 2011 of the transactions with Williams or its affiliates (including amounts in discontinued operations) discussed above:

	2011
	(Millions)
Product revenues—sales of NGLs to Williams Partners	$258
Gas management revenues—sales of natural gas for fuel and shrink to Williams Partners and another Williams subsidiary	586
Lease and facility operating expenses from Williams-direct employee salary and benefit costs	21
Gathering, processing and transportation expense from services with Williams Partners:	
Gathering and processing	298
Transportation	44
General and administrative from Williams:	
Direct employee salary and benefit costs	111
Charges for general and administrative services	62
Allocated general corporate costs	62
Other	16
Interest expense on notes payable to Williams	96

Note 4. Investment Income and Other

Investment income

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Equity earnings- Petrolera Entre Lomas S.A.	$19	$26	$20
Equity earnings- other	4	4	4
Impairment of equity method investment in Appalachian Basin	(20)	—	—
Other	2	—	2
Total investment income and other	$5	$30	$26

The nature of the assets in the equity method investment in the Appalachian Basin is such that under normal circumstances an entity would capitalize and evaluate the assets as part of its producing properties. Therefore, our ability to recover the carrying amount of our investment lies in the value of our producing properties that utilize the assets of the entity. As a result of the 2013 impairment of the producing properties in the Appalachian Basin, we recorded an impairment of the equity method investment in 2013.

Investments

	December 31,	
	2013	2012
	(Millions)	
Petrolera Entre Lomas S.A.—40.8%	$125	$109
Other	20	36
	$145	$145

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 $7 million, $12 million and $17 million in 2013, 2012 and 2011, respectively.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Note 5. Earnings (Loss) Per Common Share from Continuing Operations

The following table summarizes the calculation of earnings per share.

	Years Ended December 31,		
	2013	2012	2011
	(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	$1,185	$(245)	$(160)
Basic weighted-average shares	200.5	198.8	197.1
Diluted weighted-average shares	200.5	198.8	197.1
Earnings (loss) per common share from continuing operations:			
Basic	$(5.91)	$(1.23)	$(0.81)
Diluted	$(5.91)	$(1.23)	$(0.81)

The following table includes amounts that have been excluded from the computation of diluted earnings per common share as their inclusion would be antidiltive due to our loss from continuing operations attributable to WPX Energy, Inc.

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Weighted-average nonvested restricted stock units and awards	2.5	1.9	2.9
Weighted-average stock options	1.1	1.0	1.2

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 2011 in the calculation of basic and diluted weighted average shares.

The table below includes information related to stock options that were outstanding at December 31, 2013 and 2012 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the fourth quarter weighted-average market price of our common shares.

	2013	2012
Options excluded (millions)	0.4	1.3
Weighted-average exercise price of options excluded	$20.24	$18.17
Exercise price range of options excluded	$20.21 - $20.97	$16.46 - $20.97
Fourth quarter weighted-average market price(a)	$19.97	$16.15

(a) Our stock began trading on the New York Stock Exchange on January 3, 2012; therefore, a fourth quarter weighted-average market price is not available for 2011.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Note 6. Asset Sales, Impairments and Exploration Expenses
In 2013, we recorded a total of $1.4 billion in impairment charges of which $1,055 million is recorded as a separate line on the Consolidated Statements of Operations, $317 million is included in exploration expense and $20 million is included in investment income and other (see Note 4). These impairments are discussed further in the sections below.
Impairments and Asset Sales
The following table presents a summary of significant gains or losses reflected in impairment of producing properties and costs of acquired unproved reserves, gain on sale, and other—net within costs and expenses. These significant adjustments are primarily associated with our domestic operations.

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Impairment of producing properties and costs of acquired unproved reserves(a)	$1,055	$225	$367
Gain on sale of Powder River Basin deep rights leasehold	$36	$—	$—
Net gain on sales of other assets	$4	$4	$1

(a) Excludes unproved leasehold property impairment, amortization and expiration included in exploration expenses.
As a result of declines in forward natural gas prices primarily during the fourth-quarter 2013 as compared to forward prices as of December 31, 2012, we performed impairment assessments of our proved producing properties and capitalized cost of acquired unproved reserves. Accordingly, we recorded the following impairments during 2013:
- $772 million impairment in the fourth quarter of proved producing oil and gas properties in the Appalachian Basin;
- $192 million impairment in the fourth quarter including $107 million of proved producing oil and gas properties and $85 million of the capitalized costs of acquired unproved reserves in the Powder River Basin;
- $88 million impairment in the Piceance Basin including impairments of capitalized costs of acquired unproved reserves of $19 million and $69 million in the third and fourth quarters, respectively, in the Kokopelli area; and,
- $3 million impairment in the fourth quarter on property in Colombia.

As a result of declines in forward natural gas and natural gas liquids prices during 2012 as compared to forward natural gas and natural gas liquids prices as of December 31, 2011, we performed impairment assessments of our proved producing properties and capitalized cost of acquired unproved reserves during 2012. Accordingly, we recorded impairments of $48 million of proved producing oil and gas properties in the Green River Basin. Additionally, we recorded a total of $102 million and $75 million in impairments of capitalized costs of acquired unproved reserves primarily in the Powder River Basin and Piceance Basin, respectively. Our impairment analyses included an assessment of undiscounted and discounted future cash flows, which considered information obtained from drilling, other activities and reserves quantities (see Note 15).
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 (see Note 15). Additionally, we recorded a $91 million impairment of our capitalized cost of acquired unproved reserves in the Powder River Basin.
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 (see Note 15).
In October 2013, we completed the sale of deep rights leasehold on approximately 140,000 net acres in the Powder River Basin for $36 million. This sale did not include our producing coal bed methane assets in the Powder River Basin.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Exploration Expenses

The following table presents a summary of exploration expenses.

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Geologic and geophysical costs	$22	$21	$18
Dry hole costs	7	4	13
Unproved leasehold property impairment, amortization and expiration	402	58	95
Total exploration expenses	$431	$83	$126

Dry hole costs in 2011 reflect an $11 million dry hole expense in connection with a Marcellus Shale well in Columbia County, Pennsylvania.

Unproved leasehold impairment, amortization and expiration in 2013 includes a $317 million impairment to estimated fair values of Appalachia leasehold, while 2011 includes a $50 million write-off of leasehold costs associated with certain portions of our Columbia County, Pennsylvania acreage that we did not plan to develop. The $317 million impairment is associated with our impairment of the producing properties in the Appalachian Basin.

Note 7. Properties and Equipment

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

	Estimated Useful Life(a) (Years)	December 31, 2013	2012
		(Millions)	
Proved properties	(b)	$11,476	$11,267
Unproved properties	(c)	423	1,156
Gathering, processing and other facilities	15-25	225	247
Construction in progress	(c)	382	497
Other	3-40	180	172
Total properties and equipment, at cost		12,686	13,339
Accumulated depreciation, depletion and amortization		(5,445)	(4,923)
Properties and equipment—net		$7,241	$8,416

(a) Estimated useful lives are presented as of December 31, 2013.
(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 Appalachian Basin and the Williston Basin and costs of acquired unproved reserves in the Powder River and Piceance Basins.

Construction in progress includes $15 million in 2013 and $44 million in 2012 related to wells located in the Powder River Basin. In order to produce gas from the coal seams, an extended period of dewatering is required prior to natural gas production. Additionally, construction in progress in 2013 includes $24 million related to exploratory well costs pending the determination of proved reserves.

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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

A rollforward of our asset retirement obligations for the years ended 2013 and 2012 is presented below.

	2013	2012
	(Millions)	
Balance, January 1	$321	$289
Liabilities incurred during the period	14	19
Liabilities settled during the period	(11)	(7)
Estimate revisions	17	(1)
Accretion expense(a)	23	21
Balance, December 31	$364	$321
Amount reflected as current	$6	$5

(a) Accretion expense is included in lease and facility operating expense on the Consolidated Statements of Operations.

Estimate revisions in 2013 are primarily associated with increases in anticipated plug and abandonment costs.

Note 8. Accounts Payable and Accrued and Other Current Liabilities

Accounts Payable

	December 31, 2013	2012
	(Millions)	
Trade	$213	$209
Accrual for capital expenditures	237	126
Royalties	130	106
Cash overdrafts	35	34
Other	37	34
	$652	$509

Accrued and other current liabilities

	December 31, 2013	2012
	(Millions)	
Taxes other than income taxes	$41	$54
Accrued interest	43	42
Compensation and benefit related accruals	52	52
Other, including other loss contingencies	54	53
	$190	$201

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Note 9. Debt and Banking Arrangements
As of the indicated dates, our debt consisted of the following:

	December 31, 2013(a) (Millions)	2012 (a)
5.250% Senior Notes due 2017	$400	$400
6.000% Senior Notes due 2022	1,100	1,100
Credit facility agreement	410	—
Apco	8	8
Other	1	2
Total debt	$1,919	$1,510
Less: Current portion of long-term debt	3	2
Total long-term debt	$1,916	$1,508

(a) Interest paid on debt totaled $91 million and $58 million for 2013 and 2012, respectively.

Senior Notes

In November 2011, we issued $1.5 billion in face value Senior Notes (“the 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 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 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

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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.
Notes Registration. In June 2012, we completed an exchange offer whereby we exchanged our privately-placed Notes for like principal amounts of registered 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022. The exchange offer fulfilled our obligations under the registration rights agreement that we entered into as part of the November 2011 issuance.
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. As of December 31, 2013, the weighted average variable interest rate was 2.27 percent on the $410 million outstanding under the Credit Facility Agreement. Subsequent to December 31, 2013, we have borrowed an additional net amount of $195 million under the Credit Facility Agreement. Interest on borrowings under the Credit Facility Agreement will be payable at rates per annum equal to, at our option: (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 we select and our credit rating. Additionally, we 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 are adjusted to reflect the impact of hedges, our lenders' commodity price forecasts, and, if necessary, to include 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%. We were in compliance with our debt covenant ratios as of December 31, 2013. Investment Grade Date means the first date on which our long-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 entered into 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, 2013 a total of $361 million in letters of credit have been issued.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Apco
Apco had a loan agreement with a financial institution for a $10 million bank line of credit. As of December 31, 2013, Apco had borrowed $8 million under this banking agreement. Principal amounts will be repaid in installments through 2016. 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.
Note 10. Provision (Benefit) for Income Taxes
The provision (benefit) for income taxes from continuing operations includes:

	Years Ended December 31,		
	2013	2012	2011
	(Millions)		
Provision (benefit):			
Current:			
Federal	$(29)	$48	$49
State	1	3	7
Foreign	18	14	10
	(10)	65	66
Deferred:			
Federal	(608)	(162)	(139)
State	(51)	(13)	(1)
Foreign	14	(1)	—
	(645)	(176)	(140)
Total provision (benefit)	$(655)	$(111)	$(74)

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,		
	2013	2012	2011
	(Millions)		
Provision (benefit) at statutory rate	$(646)	$(120)	$(79)
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(110)	(10)	(5)
State income change in valuation allowance (net of federal benefit)	80	3	—
Effective state income tax rate change (net of federal benefit)	(3)	—	9
Alternative minimum tax credits	—	11	—
Argentina capital tax (net of federal benefit)	10	—	—
Foreign operations	5	4	—
Other	9	1	1
Provision (benefit) for income taxes	$(655)	$(111)	$(74)

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Significant components of deferred tax liabilities and deferred tax assets are as follows:

	December 31, 2013	2012
	(Millions)	
Deferred tax liabilities:		
Properties and equipment	$ 963	$ 1,652
Other, net	36	19
Total deferred tax liabilities	999	1,671
Deferred tax assets:		
Accrued liabilities and other	176	176
Alternative minimum tax credits	76	99
Loss carryovers	89	31
Other	21	—
Total deferred tax assets	362	306
Less: valuation allowance	102	19
Total net deferred tax assets	260	287
Net deferred tax liabilities	$ 739	$ 1,384

Net cash refunds for domestic income taxes were $26 million in 2013 while net cash payments were $40 million and $10 million in 2012 and 2011, respectively. Additionally, payments made directly to foreign taxing authorities were $14 million, $11 million and $10 million in 2013, 2012 and 2011, respectively.

As of December 31, 2013, the Company has approximately $114 million of federal net operating loss ("NOL") carryovers which begin expiring after 2033, as well as approximately $825 million of state NOL carryovers, primarily in Pennsylvania, of which more than 90 percent expire after 2029.

Income (loss) from continuing operations before income taxes includes foreign income of $50 million, $52 million and $40 million in 2013, 2012 and 2011, respectively. This income is attributable to our 69 percent investment in Apco, a Cayman Islands corporation with operations in Argentina and Colombia. The statutory income tax rate in Argentina is 35 percent while the rate in Colombia is 25 percent with an additional 9 percent for certain items.

We have recorded valuation allowances against deferred tax assets attributable primarily to our operations in Pennsylvania and Apco's operations in Colombia. In determining whether to record a valuation allowance we assess available positive and negative evidence to evaluate whether it is more likely than not that we will realize the benefit of a deferred tax asset. We have historically generated NOLs in Pennsylvania where we file separately, plus they have an annual limitation that impacts our ability to use NOL carryovers to reduce future taxable income in Pennsylvania. Apco has historically generated NOLs from its Colombia operations. As a result of our assessment of available evidence, valuation allowances were recorded to reduce recognized tax assets, net of federal benefit, to an amount that will more likely than not be realized by the Company.

Undistributed earnings of Apco at December 31, 2013, excluding amounts related to Apco's equity investment in Petrolera Entre Lomas S.A. ("Petrolera") totaled approximately $76 million. No provision for deferred U.S. income taxes has been made for those undistributed earnings because it is our intent to reinvest Apco's earnings in its operation in Argentina and Colombia. U.S income taxes have been accrued as required by GAAP, however, to the extent book basis exceeds tax basis in Apco's equity investment in Petrolera.

In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of Apco. The new 10 percent dividend tax will be accrued by Apco when dividends are paid by its Argentine investments in future periods. The capital gains tax applies to the sale of Argentine securities by a non-Argentine resident, such as Apco, making such sales subject to an effective 13.5 percent tax on the gross proceeds. As a result, Apco recorded approximately $14 million of foreign deferred tax expense during third quarter 2013 for the excess book basis over tax basis in its equity investment in Petrolera, of which approximately $12 million relates to basis differences that occurred prior to 2013. This accrual was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX related to the additional Argentine tax.

Employee share-based compensation attributable to the exercise of stock options and vesting of restricted stock is deductible by us for tax purposes. To the extent these tax deductions exceed the previously accrued deferred tax benefit for these items the additional tax benefit is not recognized under GAAP until the deduction reduces current taxes payable. Since the additional tax benefit does not reduce our current taxes payable for 2013, these tax benefits are not included in the Company's loss carryovers deferred tax asset. The additional tax benefit deductible for tax purposes but not included in our loss carryovers deferred tax asset as of December 31, 2013 totaled $7 million.
Through the effective date of the spin-off, December 31, 2011, 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 for 2011 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. 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.
In connection with the spin-off, alternative minimum tax credits were estimated and allocated between Williams and the Company effective December 31, 2011. This resulted in the allocation to the Company of a $98 million deferred tax asset with a corresponding increase to additional paid-in-capital. Subsequent to the spin-off, Williams notified the Company of certain corrections that resulted in $15 million of reductions in the alternative minimum tax credit allocated to the Company of which $11 million is a reduction of the benefit for income taxes in 2012.
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 third quarter of 2012, Williams finalized settlements with the IRS for 2009 and 2010. We were recently notified that the IRS has commenced an audit of Williams' 2011 consolidated tax filing. The statute of limitations for most states expires one year after expiration of the IRS statute. Income tax returns for Apco's operations in Argentina are open to audit for the 2006 to 2013 tax years.
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.
As of December 31, 2013, the Company has no significant unrecognized tax benefits. 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 an unrecognized tax benefit.

Note 11. 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 related to 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 related to the issue of 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. Plaintiffs had claimed damages of approximately $20 million plus interest for the period from July 2000 to July 2008. The court issued pretrial orders finding that we do bear the burden of demonstrating enhancement of the value of gas in order to deduct transportation costs and that the enhancement test must be applied on a monthly basis in order to determine the reasonableness of post-production transportation costs. Trial occurred in December 2013 on the issue of whether we have met that burden. Following that trial, the court issued its order rejecting plaintiffs' proposed standard and accepting our position as to the methodology to use in determining the standard by which our activity should be judged. We are in the process of conducting an accounting under that standard. However, we continue to believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law.

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 presently alleges failure to pay royalty on hydrocarbons including drip condensate, breach of the duty of good faith and fair dealing, fraud, fraud concealment, conversion, misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons in Colorado, violation of the New Mexico Oil and Gas Proceeds Payment Act, and bad faith breach of contract. Plaintiffs seek monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter has been removed to the United States District Court for New Mexico. In August 2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico, violation of the New Mexico Oil and Gas Proceeds Payment Act and seek declaratory judgment, accounting and injunction. 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.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in 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 are monitoring 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 guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. 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 and, independent of the issuance of additional guidance, ONRR asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas. 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 2007 through December 2013, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $106 million.

Environmental matters

The Environmental Protection Agency ("EPA"), other federal agencies, 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, green completions, 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 Federal Energy Regulatory Commission ("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 currently have a settlement agreement in principle with certain California utilities aimed at eliminating and substantially reducing this exposure. Once finalized, the settlement agreement will 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 will 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 and 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 appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion on the Western States Antitrust Litigation. The panel held that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims, reversing the summary judgment entered in favor of the defendants. The panel further held that the district court did not abuse its discretion in denying the plaintiffs' motions for leave to amend complaints. Defendants' filed a petition for writ of certiorari with the U.S. Supreme Court. 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.

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, 2013, 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.

Summary

As of December 31, 2013 and December 31, 2012, the Company had accrued approximately $16 million and $18 million, respectively, for loss contingencies associated with royalty litigation and other contingencies. In 2013, we accrued and settled certain royalty litigation matters for approximately $8 million. 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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Commitments
As part of managing our commodity price risk, we utilize contracted pipeline capacity 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, 2013 are as follows:

	(Millions)
2014	$224
2015	219
2016	197
2017	178
2018	167
Thereafter	578
Total	$1,563

We also have certain commitments (including commitments to an equity investee), primarily for natural gas gathering and treating services and well completion services, which total $389 million over approximately six 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 November 2014.
In connection with a gathering agreement entered into by Williams Partners 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 Shale) at market prices from the same third party. Purchases under the 12-year contract began 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.
Future minimum annual rentals under noncancelable operating leases as of December 31, 2013, are payable as follows:

	(Millions)
2014	$58
2015	50
2016	29
2017	8
2018	7
Thereafter	22
Total	$174

Total rent expense, excluding amounts capitalized, was $27 million, $20 million and $12 million in 2013, 2012 and 2011, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting; however, charges for rig release penalties or long term standby charges are expensed as incurred.
Note 12. Employee Benefit Plans
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. Total contributions to this plan were $16 million and $6 million for 2013 and 2012, respectively. Approximately $11 million and $10 million were included in accrued and other current liabilities at December 31, 2013 and December 31, 2012, respectively, related to the non-matching annual employer contribution.

Prior to spin-off

Through the spin-off date, certain benefit costs associated with direct employees who supported our operations were 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 3, 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 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 Sheets do not reflect any assets or liabilities related to these plans.

Pension plans

Williams is the sponsor of noncontributory defined benefit pension plans that provide pension benefits for its eligible employees. Pension expense charged to us by Williams for 2011 totaled $8 million.

Other postretirement benefits

Williams is the sponsor of subsidized retiree medical and life insurance benefit plans ("other postretirement benefits") that provide 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 totaled less than $1 million.

Defined contribution plan

Williams also is the sponsor of a defined contribution plan that provides benefits to certain eligible participants and charged us compensation expense of $4 million in 2011 for Williams' matching contributions to this plan.

Note 13. Stock-Based Compensation

WPX Energy, Inc. 2011 Incentive Plan

Subsequent to the spin-off, we have an equity incentive plan ("2011 Incentive Plan") and an employee stock purchase plan ("ESPP"). 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 million shares. The 2011 Incentive Plan is administered by either the full Board of Directors or a committee as designated by the Board of Directors, determined by the grant. Our employees, officers and non-employee directors are eligible to receive awards under the 2011 Incentive Plan.

The ESPP 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 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 million shares, subject to adjustment for stock splits and similar events. The first offering under the ESPP commenced on March 1, 2012 and ended on June 30, 2012. Subsequent offering periods are from January through June and from July through December. Employees purchased 117 thousand shares at an average price of $14.33 per share during 2013.

The Williams Companies, Inc. Incentive Plan

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.

Through the date of spin-off, we were charged by Williams for stock-based compensation expense related to our direct employees. Williams also charged us for the allocated costs of certain indirect employees of Williams (including stock-based compensation) who provided general and administrative services on our behalf. However, information included in this note is

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limited to stock-based compensation associated with the direct employees for 2011. See Note 3 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.

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.

Total stock-based compensation expense (including amount charged to us by Williams) reflected in general and administrative expense for the years ended December 31, 2013, 2012 and 2011 was $31 million, $28 million and $18 million, respectively. Measured but unrecognized stock-based compensation expense at December 31, 2013 was $41 million. This amount is comprised of $1 million related to stock options and $40 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 2.0 years.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2013.

	WPX Plan		
Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2012(a)	4.1	$12.68	$14
Granted	0.4	$14.41	
Exercised	(0.4)	$8.86	
Forfeited	—	$16.46	
Expired	—	$19.26	
Outstanding at December 31, 2013(a)	4.1	$13.27	$29
Exercisable at December 31, 2013	3.2	$12.62	$25

(a) Includes approximately 344 thousand shares held by Williams' employees at a weighted average price of $9.24 per share at December 31, 2013 and 598 thousand shares held by Williams' employees at a weighted average price of $8.48 per share at December 31, 2012.

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012 and 2011 was $5 million, $5 million and $7 million, respectively.

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, 2013.

	WPX Plan Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life
	(Millions)		(Years)	(Millions)		(Years)
$5.50 to $6.02	0.8	$5.95	4.5	0.8	$5.95	4.5
$9.08 to $11.75	0.9	$11.34	4.3	0.9	$11.34	4.3
$12.00 to $15.67	1.1	$14.45	5.4	0.7	$14.47	2.9
$16.46 to $20.97	1.3	$18.17	6.4	0.8	$18.48	5.9
Total	4.1	$13.27	5.3	3.2	$12.62	4.5

The estimated fair value at date of grant of options for our common stock and date of conversion for WPX awards in each respective year, using the Black-Scholes option pricing model, is as follows:

	WPX Plan 2013		2012		2011	
Weighted-average grant date fair value of options granted	$6.04		$7.79		$—	
Weighted-average conversion date fair value options granted					$8.48	
Weighted-average assumptions:						
Dividend yield	—		—		—	
Volatility	42.8	%	43.8	%	45.0	%
Risk-free interest rate	1.06	%	1.17	%	0.38	%
Expected life (years)	6.0		6.0		2.8	

For 2013 and 2012, we determined that the Williams stock option grant data was not relevant for valuing WPX options; therefore the Company used the SEC simplified method. The expected volatility is based primarily on the historical volatility of comparable peer group stocks. The risk free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life is assumed based on the SEC simplified method.
For 2011, the weighted average fair value is a component of the intrinsic value calculation at spin-off. The expected volatility yield is based on the historical volatility of comparable peer group stocks. The risk free 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.
Cash received from stock option exercises was $4 million and $2 million during 2013 and 2012, respectively.

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, 2013.

Restricted Stock Units	WPX Plan Shares (Millions)	Weighted-Average Fair Value(a)
Nonvested at December 31, 2012	4.8	$16.45
Granted	2.2	$14.97
Forfeited	(0.2)	$16.61
Vested	(1.6)	$11.27
Nonvested at December 31, 2013	5.2	$16.97

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(a) 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

	WPX Plan 2013	2012	Williams Plan 2011
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$14.97	$17.35	$27.74
Total fair value of restricted stock units vested during the year (millions)	$18	$14	$10

Performance-based shares granted represent 17 percent of nonvested restricted stock units outstanding at December 31, 2013. 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 14. 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 for 2013, 2012 or 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.

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 15. 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

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WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

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 or swaptions and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings.
- 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.

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. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, restricted cash, and margin deposits and customer margin deposits payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(Millions)				(Millions)		
Energy derivative assets	$30	$26	$1	$57	$20	$38	$2	$60
Energy derivative liabilities	$83	$38	$1	$122	$11	$1	$3	$15
Total debt(a)	$—	$1,945	$—	$1,945	$—	$1,617	$—	$1,617

(a) The carrying value of total debt, excluding capital leases, was $1,918 million and $1,508 million as of December 31, 2013 and 2012, respectively.

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps, options and swaptions. These are carried at fair value on the Consolidated Balance Sheets.

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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

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 or as swaptions and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us. Significant inputs into our Level 2 valuations include commodity prices, implied volatility, 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. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings. 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 24 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, 2013, consist primarily of natural gas index transactions that are used to manage our physical requirements.

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, 2013 or 2012. 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.

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.

	Years ended December 31,		
	2013	2012	2011
	Net Energy Derivatives	Net Energy Derivatives	Net Energy Derivatives
	(Millions)		
Beginning balance	$(1)	$1	$1
Realized and unrealized gains (losses):			
Included in income (loss) from continuing operations	(2)	3	15
Included in other comprehensive income (loss)	—	—	—
Purchases, issuances, and settlements	3	(5)	(12)

Transfers out of Level 3	—	—	(3)
Ending balance	$—	$(1)	$1
Unrealized gains included in income (loss) from continuing operations relating to instruments still held at December 31	$(1)	$(1)	$1

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WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statements of Operations.

For the year ending December 31, 2011, the entire $12 million reduction to level 3 fair value measurements are settlements.

As previously noted, 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. On several occasions in the past three years, we considered the significant declines in forward natural gas and NGL prices as compared to the previous respective period's forward prices to be indicators of a potential impairment. As a result, we assessed the carrying value of our natural gas-producing properties and costs of acquired unproved reserves for impairments as of the dates of those declines. Our assessments utilized estimates of future cash flows, including in some instances potential disposition proceeds. Significant judgments and assumptions in these assessments include estimates of proved, probable and possible reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, future natural gas liquids prices, expectation for market participant drilling plans, expected capital costs and an applicable discount rate commensurate with the risk of the underlying cash flow estimates. In each of the three years ended December 31, 2013, our assessments identified certain properties with a carrying value in excess of their calculated fair values and as a result, we recorded impairment charges. 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,					
	2013		2012		2011	
	(Millions)					
Impairments:						
Producing properties and costs of acquired unproved reserves (Note 6)	1,055	(a)	225	(b)	367	(c)
Unproved leasehold	317	(a)	—		—	
Equity method investment (Note 4)	20		—		—	
	$1,392		$225		$367	

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(a) As a result of our impairment assessment in 2013, we recorded the following significant impairment charges for which the fair value measured for these properties at December 31, 2013 was estimated to be approximately $365 million

- $792 million impairment charge related to natural gas producing properties and an equity method investment in the Appalachian Basin. Significant assumptions in valuing these properties included proved reserves quantities of more than 299 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.60 per Mcfe for natural gas (adjusted for locational differences), and an after-tax discount rate of 11 percent.
- $317 million impairment charge on our unproved leasehold acreage in the Appalachian Basin as a result of the impairment of the producing properties. Significant assumptions included estimates of the value per acre based on our recent transactions and those transactions observed in the market.
- $107 million impairment charge related to natural gas producing properties in the Powder River Basin. Significant assumptions in valuing these properties included proved reserves quantities of more than 294 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.53 per Mcfe for natural gas (adjusted for locational differences), and an after-tax discount rate of 11 percent.
- $88 million impairment charge related to acquired unproved reserves in the Piceance Basin. 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.
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$85 million impairment charge related to acquired unproved reserves in the Powder River Basin. 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 15 percent and 18 percent for probable and possible reserves, respectively.

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Notes to Consolidated Financial Statements—(Continued)

(b) As a result of our impairment assessments in 2012, we recorded the following significant impairment charges for which the fair value measured for these properties at December 31, 2012 was estimated to be approximately $351 million.

- $102 million and $75 million of impairment charges related to acquired unproved reserves in the Powder River Basin and Piceance Basin, respectively. 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.
- $48 million impairment charge related to natural gas-producing properties in the Green River Basin. Significant assumptions in valuing these properties included proved reserves quantities of more than 29 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $5.87 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rate of 11 percent.

(c) As a result of our impairment assessments in 2011, we recorded the following significant impairment charges for which the fair value measured for these properties at December 31, 2011, was estimated to be approximately $546 million.

- $276 million impairment charge related to natural gas-producing properties in the Powder River Basin. 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.
- $91 million impairment charge related to acquired unproved reserves in the Powder River Basin. 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.

Note 16. Derivatives and Concentration of Credit Risk

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, oil and natural gas liquids attributable to commodity price risk. Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we entered into commodity derivative contracts that continued to serve as economic hedges but were not designated as cash flow hedges for accounting purposes as we elected not to utilize this method of accounting on new derivatives instruments. Remaining commodity derivatives recorded at December 31, 2011 that were designated as cash flow hedges were fully realized by the end of the first quarter of 2013.

We produce, buy and sell natural gas, crude oil and natural gas liquids at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in commodity market prices, we enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas, crude oil and natural gas liquids. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Our financial option contracts are either purchased options, a combination of options that comprise a net purchased option or a zero-cost collar or swaptions.

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 economically hedge the expected cash flows generated by those agreements.

The following table sets forth the derivative notional volumes that are economic hedges of production volumes as well as notional volumes of the net long (short) positions of derivatives primarily related to storage and transportation contracts, both which are included in our commodity derivatives portfolio as of December 31, 2013.

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Notes to Consolidated Financial Statements—(Continued)

Derivatives related to production

Commodity	Period	Contract Type(a)	Location	Notional Volume(b)		Weighted Average Price(c)	
Crude Oil	2014	Fixed Price Swaps	WTI	(13,243	)	$94.82	
Crude Oil	2014	Basis Swaps	Brent	(4,463	)	$9.64	
Natural Gas	2014	Fixed Price Swaps	Henry Hub	(315	)	$4.19	
Natural Gas	2014	Swaptions	Henry Hub	(50	)	$4.24	
Natural Gas	2014	Costless Collars	Henry Hub	(165	)	$ 4.01 - 4.64	
Natural Gas	2014	Basis Swaps	Northeast	(23	)	$0.09	
Natural Gas	2014	Basis Swaps	MidCon	(39	)	$(0.18	)
Natural Gas	2014	Basis Swaps	Rockies	(78	)	$(0.18	)
Natural Gas	2014	Basis Swaps	West	(27	)	$0.08	
NGL - Ethane	2014	Fixed Price Swaps	Mont Belvieu	(986	)	$0.28	
NGL - Natural Gasoline	2014	Fixed Price Swaps	Mont Belvieu	(822	)	$2.05	
Crude Oil	2015	Swaptions	WTI	(1,750	)	$98.54	
Natural Gas	2015	Fixed Price Swaps	Henry Hub	(35	)	$4.38	
Natural Gas	2015	Swaptions	Henry Hub	(35	)	$4.38	

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type(d)	Location(e)	Notional Volume(b)		Weighted Average Price(f)
Natural Gas	2014	Fixed Price Swaps	Multiple	(11	)	—
Natural Gas	2014	Basis Swaps	Multiple	(31	)	—
Natural Gas	2014	Index	Multiple	(107	)	—
Natural Gas Liquids	2014	Fixed Price Swaps	Multiple	(822	)	—
Natural Gas	2015	Basis Swaps	Multiple	(6	)	—
Natural Gas	2015	Index	Multiple	(43	)	—
Natural Gas	2016	Index	Multiple	2		—
Natural Gas	2017	Index	Multiple	2		—

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(a) Derivatives related to crude oil production are business day average swaps, basis swaps, and swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, swaptions and costless collars. The derivatives related to natural gas liquids are fixed price swaps. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us.

(b) Natural gas volumes are reported in BBtu/day, crude oil volumes are reported in Bbl/day, and natural gas liquids are reported in Bbl/day.

(c) The weighted average price for natural gas is reported in $/MMBtu, the crude oil price is reported in $/Bbl and natural gas liquids are reported in $/Gallon.

(d) WPX Marketing enters into exchange traded fixed price and basis swaps, over the counter fixed price and basis swaps, physical fixed price transactions and transactions with an index component.

(e) WPX Marketing transacts at multiple locations primarily around our core assets to maximize the economic value of our transportation, storage and asset management agreements.

(f)

The weighted average price is not reported since the notional volumes represent a net position comprised of buys and sells with positive and negative transaction prices.

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 Sheets 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

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

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, 2013 Assets (Millions)	Liabilities	2012 Assets	Liabilities
Derivatives related to production designated as hedging instruments	$—	$—	$5	$—
Not designated as hedging instruments:				
Derivatives related to production not designated as hedging instruments	26	39	33	—
Derivatives related to physical marketing agreements not designated as hedging instruments	31	83	20	13
Legacy natural gas contracts from former power business	—	—	2	2
Total derivatives not designated as hedging instruments	57	122	55	15
Total derivatives	$57	$122	$60	$15

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, 2013 (Millions)	2012	Classification
Net gain recognized in other comprehensive income (loss) (effective portion)	$—	$90	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion)(a)	$5	$434	Revenues

(a) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains on derivatives designated as hedges of our production and are reflected in natural gas sales and oil and condensate sales.

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The cash flow impact of our derivative activities is presented in the Consolidated Statements of Cash Flows as changes in current and noncurrent derivative assets and liabilities.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

Offsetting of derivative assets and liabilities
The following table presents our gross and net derivative assets and liabilities.

December 31, 2013	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted(Received)	Net Amount
Derivative assets with right of offset or master netting agreements	$57	$(50)	$ —	$7
Derivative liabilities with right of offset or master netting agreements	$(122)	$50	$ 52	$(20)
December 31, 2012				
Derivative assets with right of offset or master netting agreements	$60	$(10)	$ (2)	$48
Derivative liabilities with right of offset or master netting agreements	$(15)	$10	$ —	$(5)

(a) With all of our financial trading counterparties, we have agreements in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements. Additionally, we have negotiated master netting agreements with some of our counterparties. These master netting agreements allow multiple entities that have multiple underlying agreements the ability to net derivative assets and derivative liabilities at settlement or in the event of a default or a termination under one or more of the underlying contracts.

Credit-risk-related features
Certain of our derivative contracts contain credit-risk-related provisions that would require us, under certain events, 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 Investment Services. 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.

As of December 31, 2013, we had collateral totaling $71 million posted to derivative counterparties, which includes $19 million of initial margin to clearinghouses or exchanges to enter into positions and $52 million of maintenance margin for changes in fair value of those positions, to support the aggregate fair value of our net $72 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, 2012, we had collateral totaling $2 million posted to derivative counterparties to support the aggregate fair value of our net $5 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), 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 $20 million and $3 million at December 31, 2013 and December 31, 2012, 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. During the first quarter of 2012, approximately $15 million of unrealized gains were recognized into earnings in 2012

for hedge transactions where the underlying transactions were no longer probable of occurring due to the sale of our Barnett Shale properties. The $15 million gain is included in net gains (losses) on derivatives not designated as hedges on the Consolidated Statements of Operations for 2012, as are second-quarter 2012 changes in forward mark to market value. As of December 31, 2012, we had hedged portions of future cash flows associated with anticipated energy commodity sales for three months. Based on recorded values at December 31, 2012, $3 million of net gains (net of income tax provision of $2 million) were reclassified into earnings in the first quarter of 2013. These recorded values are based on market prices of the commodities as of December 31, 2012. Actual gains or losses realized in the first quarter of 2013 matched these values. These gains substantially offset net losses that were realized in earnings from previous unfavorable 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, net of allowances, by product or service as of December 31:

	2013 (Millions)	2012
Receivables by product or service:		
Sale of natural gas and related products and services	$339	$289
Joint interest owners	186	138
Other	11	16
Total	$536	$443

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 2013, 2012 and 2011, we did not incur any significant losses due to counterparty bankruptcy filings. 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 gross and net credit exposure from our derivative contracts as of December 31, 2013, is summarized as follows:

Counterparty Type	Gross Investment Grade(a) (Millions)	Gross Total	Net Investment Grade(a)	Net Total
Financial institutions	57	57	7	7
Credit reserves		—		—
Credit exposure from derivatives		$57		$7

(a) 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 three largest net counterparty positions represent approximately 89 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

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Other

At December 31, 2013, we held collateral support of approximately $55 million, either in the form of cash or letters of credit, related to our gas management sale agreements.

Revenues

During 2013, 2012, and 2011, BP Energy Company, a domestic segment customer, accounted for 15 percent, 10 percent and 11 percent of our consolidated revenues, respectively. During 2013, Southern California Gas Company accounted for 11 percent of our consolidated revenues. Williams accounted for 8 percent and 12 percent of our consolidated revenue for 2013 and 2012 respectively. Prior to 2012, Williams was considered an affiliate of WPX. See Note 3 for revenue related to Williams for 2011. 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 17. 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). There are no intersegment sales between domestic and international.

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 Statements of Operations. Long-lived assets are comprised of gross property, plant and equipment and long-term investments.

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

For the year ended December 31, 2013	Domestic	International (Millions)	Total
Total revenues	$2,609	$152	$2,761
Costs and expenses:			
Lease and facility operating	$271	$37	$308
Gathering, processing and transportation	430	3	433
Taxes other than income	117	24	141
Gas management, including charges for unutilized pipeline capacity	931	—	931
Exploration	424	7	431
Depreciation, depletion and amortization	906	34	940
Impairment of producing properties and costs of acquired unproved reserves	1,052	3	1,055
Gain on sale of Powder River Basin deep rights leasehold	(36)	—	(36)
General and administrative	275	14	289
Other—net	17	—	17
Total costs and expenses	$4,387	$122	$4,509
Operating income (loss)	$(1,778)	$30	$(1,748)
Interest expense	(108)	—	(108)
Interest capitalized	5	—	5
Investment income, impairment of equity method investment and other	(16)	21	5
Income (loss) from continuing operations before income taxes	$(1,897)	$51	$(1,846)
Other financial information:			
Net capital expenditures	$1,103	$51	$1,154
Total assets	$8,046	$383	$8,429
Long—lived assets	$12,346	$485	$12,831
For the year ended December 31, 2012			
Total revenues	$3,052	$137	$3,189
Costs and expenses:			
Lease and facility operating	$251	$32	$283
Gathering, processing and transportation	504	2	506
Taxes other than income	87	24	111
Gas management, including charges for unutilized pipeline capacity	996	—	996
Exploration	72	11	83
Depreciation, depletion and amortization	939	27	966
Impairment of producing properties and costs of acquired unproved reserves	225	—	225
General and administrative	273	14	287
Other—net	12	—	12
Total costs and expenses	$3,359	$110	$3,469
Operating income (loss)	$(307)	$27	$(280)
Interest expense	(102)	—	(102)
Interest capitalized	8	—	8
Investment income and other	3	27	30
Income (loss) from continuing operations before income taxes	$(398)	$54	$(344)
Other financial information:			
Net capital expenditures	$1,463	$58	$1,521

Total assets	$9,113	$343	$9,456
Long-lived assets	$13,056	$428	$13,484

WPX Energy, Inc.
Notes to Consolidated Financial Statements—(Continued)

For the year ended December 31, 2011	Domestic	International (Millions)	Total
Total revenues	$3,772	$110	$3,882
Costs and expenses:			
Lease and facility operating	$235	$27	$262
Gathering, processing and transportation	487	—	487
Taxes other than income	113	21	134
Gas management, including charges for unutilized pipeline capacity	1,471	—	1,471
Exploration	123	3	126
Depreciation, depletion and amortization	880	22	902
Impairment of producing properties and costs of acquired unproved reserves	367	—	367
General and administrative	263	12	275
Other—net	(3)	3	—
Total costs and expenses	$3,936	$88	$4,024
Operating income (loss)	$(164)	$22	$(142)
Interest expense	(117)	—	(117)
Interest capitalized	9	—	9
Investment income and other	6	20	26
Income (loss) from continuing operations before income taxes	$(266)	$42	$(224)
Other financial information:			
Net capital expenditures	$1,531	$41	$1,572
Total assets	$10,144	$288	$10,432
Long—lived assets	$11,969	$354	$12,323

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)			
2013				
Revenues	$631	$815	$658	$657
Operating costs and expenses	710	689	687	1,098
Income (loss) from continuing operations	(113)	22	(116)	(984)
Net income (loss)	(113)	22	(116)	(984)
Amounts attributable to WPX Energy, Inc.:				
Net income (loss)	(116)	18	(114)	(973)
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$(0.58)	$0.09	$(0.57)	$(4.85)
2012				
Revenues	$910	$775	$677	$827
Operating costs and expenses	834	673	680	758
Income (loss) from continuing operations	(38)	(29)	(63)	(103)
Net income (loss)	(40)	(6)	(61)	(104)
Amounts attributable to WPX Energy, Inc.:				
Net income (loss)	(43)	(10)	(64)	(106)
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$(0.21)	$(0.17)	$(0.33)	$(0.53)

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 2013 includes the following pre-tax items:

- $1,373 million of impairments of costs of producing properties, acquired unproved reserves, leasehold and equity method investment (see Note 4 and Note 6).
- $36 million gain on the sale of deep rights in the Powder River Basin.
- $9 million buyout of a transportation agreement.

Net loss for third-quarter 2013 includes the following pre-tax items:

- $19 million of impairments of costs of acquired unproved reserves in the Kokopelli area of the Piceance Basin (see Note 6).
- $7 million accrual for litigation.

Net loss for fourth-quarter 2012 includes the following pre-tax items:

- $108 million of impairments of producing properties and costs of acquired unproved reserves (see Note 6).

Net loss for second-quarter 2012 includes the following pre-tax items:

- $65 million of impairments of costs of acquired unproved reserves in the Powder River Basin (see Note 6).
- Gain on sale of Barnett and Arkoma properties.

Net loss for first-quarter 2012 includes the following pre-tax items:

- $52 million of impairments of costs of acquired unproved reserves primarily in the Powder River Basin (see Note 6).

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures
(Unaudited)

We have significant oil and gas producing activities primarily in the Piceance and San Juan Basins in the Rocky Mountain region, the Williston Basin in North Dakota and the Appalachian Basin in Pennsylvania, all of which are located in 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 and the Results of Operations for all years presented, the following information includes information, through the date of sale in 2012, for the holdings in the Barnett Shale and Arkoma Basin which have been reported as discontinued operations in our consolidated financial statements. These operations represented less than five percent of our total domestic and international proved reserves in 2011.

Capitalized Costs

	As of December 31, 2013			
	Domestic	International	Consolidated Total	Entity's share of equity method investee
	(Millions)			
Proved Properties	$ 11,349	$ 350	$ 11,699	$ 330
Unproved properties	414	9	423	2
	11,763	359	12,122	332
Accumulated depreciation, depletion and amortization and valuation provisions	(5,070)	(194)	(5,264)	(195)
Net capitalized costs	$ 6,693	$ 165	$ 6,858	$ 137

	As of December 31, 2012			
	Domestic	International	Consolidated Total	Entity's share of equity method investee
	(Millions)			
Proved Properties	$ 11,295	$ 310	$ 11,605	$ 292
Unproved properties	1,153	9	1,162	1
	12,448	319	12,767	293
Accumulated depreciation, depletion and amortization and valuation provisions	(4,612)	(161)	(4,773)	(181)
Net capitalized costs	$ 7,836	$ 158	$ 7,994	$ 112

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $329 million and $365 million, net, for 2013 and 2012, 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 unproved reserves.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Cost Incurred

	Domestic	International	Entity's share of equity method investee
	(Millions)		
For the Year Ended December 31, 2013			
Acquisition	$57	$—	$—
Exploration	104	16	3
Development	939	36	34
	$1,100	$52	$37
For the Year Ended December 31, 2012			
Acquisition	$111	$—	$—
Exploration	23	31	5
Development	1,130	35	35
	$1,264	$66	$40
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 2013 and 2012 costs are primarily for undeveloped leasehold in exploratory areas targeting oil reserves. The 2011 costs are primarily for additional leasehold in the Appalachian Basin.
- 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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Results of Operations

	Domestic (Millions)	International	Total
For the Year Ended December 31, 2013			
Revenues:			
Natural gas sales	$1,074	$19	$1,093
Oil and condensate sales	534	115	649
Natural gas liquid sales	228	2	230
Net gain (loss) on derivatives not designated as hedges	(57)	—	(57)
Other revenues	6	16	22
Total revenues	1,785	152	1,937
Costs:			
Lease and facility operating	271	37	308
Gathering, processing and transportation	430	3	433
Taxes other than income	117	24	141
Exploration	424	7	431
Depreciation, depletion and amortization	906	34	940
Impairment of certain natural gas properties primarily in the Appalachian and Powder River Basins	899	3	902
Impairment of costs of acquired unproved reserves	153	—	153
Gain on sale of Powder River deep rights leasehold	(36)	—	(36)
General and administrative	268	14	282
Other (income) expense	17	—	17
Total costs	3,449	122	3,571
Results of operations	(1,664)	30	(1,634)
Provision (benefit) for income taxes	(621)	11	(610)
Exploration and production net income (loss)	$(1,043)	$19	$(1,024)

	Domestic (Millions)	International	Total
For the Year Ended December 31, 2012			
Revenues:			
Natural gas sales	$1,346	$18	$1,364
Oil and condensate sales	376	115	491
Natural gas liquid sales	296	3	299
Net gain on derivatives not designated as hedges	66	—	66
Other revenues	7	1	8
Total revenues	2,091	137	2,228
Costs:			
Lease and facility operating	251	32	283
Gathering, processing and transportation	504	2	506
Taxes other than income	87	24	111
Exploration	72	11	83
Depreciation, depletion and amortization	939	27	966
Impairment of certain natural gas properties in the Green River Basin	48	—	48
Impairment of costs of acquired unproved reserves	177	—	177
General and administrative	267	14	281
Other (income) expense	14	—	14

Total costs	2,359	110	2,469
Results of operations	(268)	27	(241)
Provision (benefit) for income taxes	(98)	10	(88)
Exploration and production net income (loss)	$(170)	$17	$(153)

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

	Domestic (Millions)	International	Total
For the Year Ended December 31, 2011			
Revenues:			
Natural gas sales	$1,678	$16	$1,694
Oil and condensate sales	226	86	312
Natural gas liquid sales	404	4	408
Other revenues	7	4	11
Total revenues	2,315	110	2,425
Costs:			
Lease and facility operating	235	27	262
Gathering, processing and transportation	487	—	487
Taxes other than income	113	21	134
Exploration	123	3	126
Depreciation, depletion and amortization	880	22	902
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	246	12	258
Other (income) expense	(3)	3	—
Total costs	2,448	88	2,536
Results of operations	(133)	22	(111)
Provision (benefit) for income taxes	(49)	8	(41)
Exploration and production net income (loss)	$(84)	$14	$(70)

- Amounts for all years exclude the equity earnings (losses) from our equity method investees. Net equity earnings (losses) from these investees were $23 million, $30 million and $24 million in 2013, 2012 and 2011, respectively.
- Natural gas revenues consist of natural gas production sold and includes realized gains (losses) of derivatives that were designated as cash flow hedges in 2012 and 2011.
- For derivative instruments that were entered into after January 1, 2012, we did not designate those as cash flow hedges. Any gain (loss) related to these derivatives is included in net gain on derivatives not designated as hedges.
- Other revenues consist of activities that are an indirect part of the producing activities.
- 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. Additionally, exploration costs in 2013 include a $317 million impairment to estimated fair value of unproved leasehold costs in the Appalachia Basin.
- Depreciation, depletion and amortization includes depreciation of support equipment.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Proved Reserves

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.

The following is a summary of and changes in our domestic and international proved reserves. Our international reserves are primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest. The Entity's share of equity method investee represents Apco's 40.8 percent interest in reserves of Petrolera Entre Lomas S.A.

	Natural Gas (Bcf)			
	Domestic	International	Entity's share of equity method investee	Combined
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
Revisions	(404.8)	(18.0)	(18.5)	(441.3)
Purchases	5.8	—	—	5.8
Divestitures	(217.0)	—	—	(217.0)
Extensions and discoveries	409.2	5.7	7.4	422.3
Production	(407.0)	(8.6)	(4.4)	(420.0)
Proved reserves at December 31, 2012	3,369.1	54.1	35.5	3,458.7
Revisions	308.3	(1.7)	(3.1)	303.5
Divestitures	(0.2)	—	—	(0.2)
Extensions and discoveries	312.0	18.5	0.9	331.4
Production	(359.4)	(7.1)	(3.3)	(369.8)
Proved reserves at December 31, 2013	3,629.8	63.8	30.0	3,723.6
Proved developed reserves:				
December 31, 2011	2,497.3	48.4	28.5	2,574.2
December 31, 2012	2,170.7	36.5	20.8	2,228.0

December 31, 2013	2,265.2	41.4	18.7	2,325.3
Proved undeveloped reserves:				
December 31, 2011	1,485.6	26.6	22.5	1,534.7
December 31, 2012	1,198.4	17.6	14.7	1,230.7
December 31, 2013	1,364.6	22.4	11.3	1,398.3

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

	Oil (MMBbls)			
	Domestic	International	Entity's share of equity method investee	Combined
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
Revisions	5.6	(1.1)	(1.1)	3.4
Divestitures	(0.3)	—	—	(0.3)
Extensions and discoveries	28.5	2.1	1.1	31.7
Production	(4.4)	(1.5)	(1.6)	(7.5)
Proved reserves at December 31, 2012	76.5	10.8	10.6	97.9
Revisions	3.5	(1.6)	(0.8)	1.1
Extensions and discoveries	28.8	0.9	—	29.7
Production	(5.9)	(1.4)	(1.5)	(8.8)
Proved reserves at December 31, 2013	102.9	8.7	8.3	119.9
Proved developed reserves:				
December 31, 2011	13.6	6.8	7.6	28.0
December 31, 2012	23.7	6.1	6.4	36.2
December 31, 2013	36.8	5.2	5.3	47.3
Proved undeveloped reserves:				
December 31, 2011	33.5	4.5	4.6	42.6
December 31, 2012	52.8	4.7	4.2	61.7
December 31, 2013	66.1	3.5	3.0	72.6

	NGLs (MMBbls)			
	Domestic	International	Entity's share of equity method investee	Combined
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
Revisions	(21.1)	—	—	(21.1)
Divestitures	(1.0)	—	—	(1.0)
Extensions and discoveries	8.9	—	—	8.9
Production	(10.4)	(0.1)	(0.1)	(10.6)
Proved reserves at December 31, 2012	110.4	0.7	0.8	111.9
Revisions	(25.4)	—	—	(25.4)
Extensions and discoveries	8.1	0.1	—	8.2
Production	(7.4)	(0.1)	(0.1)	(7.6)

Proved reserves at December 31, 2013	85.7	0.7	0.7	87.1
Proved developed reserves:				
December 31, 2011	72.1	0.6	0.6	73.3
December 31, 2012	64.9	0.5	0.6	66.0
December 31, 2013	48.6	0.5	0.5	49.6
Proved undeveloped reserves:				
December 31, 2011	61.9	0.2	0.3	62.4
December 31, 2012	45.5	0.2	0.2	45.9
December 31, 2013	37.1	0.2	0.2	37.5

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

	All products (Bcfe) (a)			
	Domestic	International	Entity's share of equity method investee	Combined
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
Revisions	(498.6)	(24.7)	(25.1)	(548.4)
Purchases	5.8	—	—	5.8
Divestitures	(224.8)	—	—	(224.8)
Extensions and discoveries	633.8	18.3	14.0	666.1
Production	(495.8)	(18.0)	(14.6)	(528.4)
Proved reserves at December 31, 2012	4,490.5	122.8	103.9	4,717.2
Revisions	177.2	(11.3)	(7.9)	158.0
Divestitures	(0.5)	—	—	(0.5)
Extensions and discoveries	533.8	24.5	0.9	559.2
Production	(439.4)	(16.2)	(12.9)	(468.5)
Proved reserves at December 31, 2013	4,761.6	119.8	84.0	4,965.4
Proved developed reserves:				
December 31, 2011	3,011.5	93.0	77.7	3,182.2
December 31, 2012	2,702.6	76.1	62.8	2,841.5
December 31, 2013	2,777.7	75.5	53.5	2,906.7
Proved undeveloped reserves:				
December 31, 2011	2,058.6	54.2	51.9	2,164.7
December 31, 2012	1,787.9	46.7	41.1	1,875.7
December 31, 2013	1,983.9	44.3	30.5	2,058.7

(a) 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.

- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit.
- The domestic revisions in 2013 reflects 133 Bcfe related to developed reserves and 44 Bcfe related to undeveloped reserves. The domestic revisions in 2012 primarily resulted from the lower 12-month average price as compared to the 12-month average price used in 2011. The domestic revisions in 2011 primarily relate to the reclassification of reserves from proved to probable reserves attributable to locations not expected to be developed within five years.
- Divestitures in 2012 primarily relate to the sale in 2012 of our holdings in the Barnett Shale and the Arkoma Basin (see Note 2 of Notes to Consolidated Financial Statements).
- Domestic extensions and discoveries in 2013 reflects 127 Bcfe added for drilled locations and 407 Bcfe added for new undeveloped locations. The 2013 extensions and discoveries were primarily in the Piceance Basin, Williston Basin, Appalachian Basin and San Juan Basin. Domestic extensions and discoveries in 2012 reflect 225 Bcfe added for drilled locations and 405 Bcfe added for new undeveloped locations. The 2012 extensions and discoveries were

primarily in the Williston Basin, Appalachian Basin and Piceance Basin. Domestic extensions and discoveries in 2011 reflect 306 Bcfe added for drilled locations and 760 Bcfe added for new undeveloped locations. The 2011 extensions and discoveries were primarily in the Piceance Basin, Appalachian Basin and Williston Basin.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

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, 2013, 2012 and 2011, the average domestic combined natural gas and NGL equivalent price was \$3.63, \$3.01 and \$4.41 per Mcfe, respectively. The average domestic oil price used in the estimates for the years ended December 31, 2013, 2012 and 2011 was \$92.16, \$82.32 and \$86.87 per barrel, respectively. 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.
Standardized Measure of Discounted Future Net Cash Flows

As of December 31, 2013	Domestic	International(a)	Entity's share of equity method investee(b)
	(Millions)		
Future cash inflows	$24,547	$866	$733
Less:			
Future production costs	12,148	360	297
Future development costs	3,789	136	109
Future income tax provisions	2,147	72	95
Future net cash flows	6,463	298	232
Less 10 percent annual discount for estimated timing of cash flows	3,499	118	85
Standardized measure of discounted future net cash inflows	$2,964	$180	$147

As of December 31, 2012	Domestic	International(a)	Entity's share of equity method investee(b)
Future cash inflows	$18,435	$968	$892
Less:			
Future production costs	9,836	385	356
Future development costs	3,217	136	115
Future income tax provisions	1,059	97	104
Future net cash flows	4,323	350	317
Less 10 percent annual discount for estimated timing of cash flows	(2,374)	(136)	(118)
Standardized measure of discounted future net cash inflows	$1,949	$214	$199

(a) Amounts primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.
(b) Represents Apco's 40.8 percent interest in Petrolera Entre Lomas S.A.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	Domestic	International(a)	Entity's share of equity method investee(b)
	(Millions)		
December 31, 2010	$2,814	$198	$186
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, less 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 in 2011	777	1	11
December 31, 2011	$3,591	$199	$197
Sales of oil and gas produced, net of operating costs	(778)	(78)	(78)
Net change in prices and production costs	(3,601)	46	49
Extensions, discoveries and improved recovery, less estimated future costs	1,154	—	—
Development costs incurred during year	333	35	35
Changes in estimated future development costs	50	(16)	(17)
Purchase of reserves in place, less estimated future costs	4	—	—
Sale of reserves in place, less estimated future costs	(272)	—	—
Revisions of previous quantity estimates	(232)	(3)	(26)
Accretion of discount	481	26	27
Net change in income taxes	1,194	5	12
Other	25	—	—
Net changes in 2012	(1,642)	15	2
December 31, 2012	$1,949	$214	$199
Sales of oil and gas produced, net of operating costs	(1,040)	(77)	(71)
Net change in prices and production costs	1,198	(5)	17
Extensions, discoveries and improved recovery, less estimated future costs	1,282	—	—
Development costs incurred during year	414	37	34
Changes in estimated future development costs	(736)	(27)	(16)
Sale of reserves in place, less estimated future costs	(3)	—	—
Revisions of previous quantity estimates	239	(17)	(61)
Accretion of discount	225	28	27
Net change in income taxes	(540)	27	18
Other	(24)	—	—
Net changes in 2013	1,015	(34)	(52)

December 31, 2013	$2,964	$180	$147

(a) Amounts primarily attributable to a consolidated subsidiary (Apco) in which there is a 31 percent noncontrolling interest.
(b) Represents Apco's 40.8 percent interest in Petrolera Entre Lomas S.A.

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WPX Energy, Inc.
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	Charged (Credited) to Costs and Expenses	Other	Deductions	Ending Balance
	(Millions)				
2013:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$11	$(3)	$—	$(1)	$7
Deferred tax asset valuation allowance(a)	19	80	3	—	102
2012:					
Allowance for doubtful accounts—accounts and notes receivable(a)	13	(2)	—	—	11
Deferred tax asset valuation allowance(a)	16	3	—	—	19
2011:					
Allowance for doubtful accounts—accounts and notes receivable(a)	16	(1)	—	(2)	13
Deferred tax asset valuation allowance(a)	22	—	—	(6) (b)	16

(a) Deducted from related assets.
(b) Deferred tax asset retained by Williams.

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.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth in Item 8, "Financial Statements and Supplementary Data."

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth in Item 8, "Financial Statements and Supplementary Data."

Fourth Quarter 2013 Changes in Internal Controls

There have been no changes during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information called for by this Item 10 is incorporated by reference to our definitive proxy statement for our 2014 Annual meeting of Stockholders, or our 2014 Proxy Statement, anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, under the headings “Proposal 1— Election of Directors,” “Corporate Governance,” and “Section 16(a) Beneficial Ownership and Reporting Compliance.”

Item 11. Executive Compensation

The information called for by this Item 11 is incorporated by reference to our 2014 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, under the headings “Executive Compensation” and “Compensation Interlocks and Insider Participation.”

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by this Item 12 is incorporated by reference to our 2014 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, under the headings “Security Ownership of Certain Beneficial Owners and Management” and “Equity Compensation Plan Information.”

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

The information called for by this Item 13 is incorporated by reference to our 2014 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, under the headings “Corporate Governance” and “Certain Relationships and Transactions.”

Item 14. Principal Accountant Fees and Services

The information called for by this Item 14 is incorporated by reference to our 2014 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, under the heading “Independent Registered Public Accounting Firm.”

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.

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	Amended and Restated Bylaws 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 November 15, 2013)
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. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
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 10.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012)(1)
10.8	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (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 July 23, 2012)(1)
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	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on May 29, 2013)(1)
10.11	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)(1)

10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.14	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.14 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.15	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.16	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.17	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.18	Agreement, dated December 17, 2013, between WPX Energy, Inc. and Taconic Capital Advisors LP (incorporated herein by reference to Exhibit 99.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 18, 2013).
10.19	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 17, 2013).
12*	Statement of Computation of Ratio of Earnings to Fixed Charges
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.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase
101.DEF**	XBRL Taxonomy Extension Definition Linkbase
101.LAB**	XBRL Taxonomy Extension Label Linkbase
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase

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.
* Filed herewith
** Furnished herewith
(1) Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WPX ENERGY, Inc.
(Registrant)

By: /s/ J. Kevin Vann
J. Kevin Vann
Controller

Date: February 27, 2014

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/ James J. Bender	President, Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2014
/s/ Rodney J. Sailor	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2014
/s/ J. Kevin Vann	Controller (Principal Accounting Officer)	February 27, 2014
/s/ Kimberly S. Bowers*	Director	February 27, 2014
/s/ John A. Carrig*	Director	February 27, 2014
/s/ William R. Granberry*	Director	February 27, 2014
/s/ Don J. Gunther*	Director	February 27, 2014
/s/ Robert K. Herdman*	Director	February 27, 2014
/s/ Kelt Kindick*	Director	February 27, 2014
/s/ Karl F. Kurz*	Director	February 27, 2014
/s/ Henry E. Lentz*	Director	February 27, 2014
/s/ George A. Lorch*	Director	February 27, 2014
/s/ William G. Lowrie*	Chairman of the Board	February 27, 2014
/s/ David F. Work*	Director	February 27, 2014

*By:	/s/ Stephen E. Brilz Attorney-in-Fact	February 27, 2014