WPX ENERGY, INC.
Form 10-K
February 26, 2015

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, 2014
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 $4,832,711,197.

The number of shares outstanding of the registrant's common stock outstanding at February 25, 2015 was 203,877,415.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be delivered to stockholders in connection with its 2015 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/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.

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—means one thousand barrels of oil equivalent.

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.

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.

Incorporated in 2011, 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.

We have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. Our domestic proved reserves at December 31, 2014 were 4,360 Bcfe. Our domestic reserves reflect a mix of 72 percent natural gas, 18 percent crude oil and 10 percent NGLs. During 2014, we replaced our domestic production for all commodities at a rate of 94 percent. For oil alone, we replaced 421 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.

Our principal areas of operation are the Piceance Basin in Colorado, the Williston Basin in North Dakota, and the San Juan Basin in New Mexico and Colorado. Our principal executive office is located at 3500 One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 855-979-2012.

BUSINESS OVERVIEW AND PROPERTIES

Our Business Strategy

Our business strategy is to increase shareholder value by increasing production over time of oil, natural gas, and NGLs, expanding our margins, and finding and developing reserves.

- Focused, Long-Term Portfolio Management. We are focused on long-term profitable growth. 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. With regard to our core assets in the Piceance, Williston, and San Juan Basins, we expect to allocate capital to the most profitable opportunities 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.
- Build Asset Scale. We expect to opportunistically acquire acreage positions in areas where we feel we can establish significant scale and replicate cost-efficient development practices. We may also consider other “bolt-on” transactions that are directed at driving operational efficiencies through increased scale. We can manage costs by focusing on the establishment of 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 a history of acquiring undeveloped properties that meet our expected 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.
- Margin Expansion thru Focus on Costs. We believe we can expand our margins by focusing on opportunities to reduce our cost structure. As we rationalize our portfolio and reduce our areas of focus to core basins, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with our margin growth objectives.
- Continue Oil Development and Increase Optionality. We believe that efforts to develop our oil properties will yield a more balanced commodity mix in our production, providing us with the option of focusing on the commodity with the best returns under different market conditions. This optionality, we believe, will place us in a position where we can better protect and grow our cash flows. 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. We have hedged approximately three-fourths of our anticipated 2015 natural gas production at a weighted average price of $4.10 per MMbtu, and approximately two-thirds of anticipated 2015 oil production at a weighted average price of $94.88 per barrel.

Significant Properties

Our principal areas of operation are the Piceance Basin, Williston Basin and San Juan Basin.

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. We operate 4,742 wells in the Piceance Basin and also own interest in 318 wells operated by others. We hold 196,149 net acres in the Piceance Basin.

During 2014, we operated an average of 8.5 drilling rigs in the basin, including 6.2 in the Piceance Valley, 1.6 in the Piceance Highlands and 0.7 in the Piceance Niobrara. In response to lower commodity prices, we expect to operate 3.5 rigs in the Piceance Basin in 2015. In 2014, we had an average of 564 MMcf per day of net gas production from our Piceance Basin properties along with an average of 14.7 Mbbls per day of NGLs and 1.9 Mbbls per day of condensate recovered from our Piceance Basin properties. Capital expenditures were approximately $523 million which included the completion of 269 gross (252 net) wells in 2014. As of December 31, 2014, another 46 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. 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 multiple 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 per day at a flowing pressure of 7,300 pounds per square inch. Additional 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. The Niobrara and Mancos Shales are generally located at depths of 10,000 to 13,000 feet. We have the lease rights to approximately 160,000 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.

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 formations, the primary targets for all of the well locations in our current drilling inventory. We operate 177 wells in the Williston Basin and also own interest in 19 wells operated by others. We hold 85,483 net acres in the Williston Basin.

During 2014, we operated an average of 4.8 rigs on our Williston Basin properties and we had an average of 22.3 Mboe per day of net production from our Williston Basin wells. In response to lower oil prices we expect to operate 1.4 rigs in the Williston Basin in 2015. Capital expenditures were approximately $632 million which included the completion of 55 gross (45 net) wells in 2014. As of December 31, 2014, another 25 gross operated wells were awaiting completion.

We are developing oil reserves through horizontal drilling in the Middle Bakken and 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 and Three Forks 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 is being 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.

Our acreage in the Williston Basin, as well as a portion of our acreage in the Piceance 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 first acquired properties in the San Juan Basin as part of The Williams Companies, Inc. (“Williams”) acquisition of Northwest Energy in 1983. 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 four units in New Mexico (Rosa, Cox Canyon, Northwest Lybrook and South Chaco) and also operate the Northeast Chaco CA (Communitized Area), as well as a number of non-unit properties. We operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We operate 945 wells in the San Juan Basin and also own interest in 2,319 wells operated by other operators in New Mexico and Colorado. We hold approximately 134,000 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. In 2014, we announced that we executed multiple transactions to own or control over 53,000 additional acres in the heart of the San Juan Basin’s Gallup oil window. At December 31, 2014, our leasehold position in the oil window of the San Juan Basin was approximately 85,000 net acres of which we own or control, and we are targeting additional acreage.

During 2014, we operated an average of 2.3 rigs in the San Juan Basin on our oil properties and we expect to operate 2.3 rigs in the San Juan Basin in 2015. We had an average of 139 MMcfe per day of net production from our San Juan Basin properties which included 3.9 Mbbls per day of oil. Capital expenditures were approximately $568 million which included the completion of 47 gross (44 net) wells from our oil properties. As of December 31, 2014, another 10 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, Bureau of Land Management (“BLM”), the Bureau of Indian Affairs, and the Federal Indian Minerals Office. 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.

Other Properties

Our other holdings, amounting to approximately 3 percent of our assets, are primarily comprised of gas reserves in the Appalachian Basin in Pennsylvania. Approximately 95 percent of our Appalachian Basin assets were sold in January 2015.

Acquisitions and Divestitures

On June 4, 2014, we announced that we had completed the sale of working interests in some of our historical Piceance Basin wells to Legacy Reserves LP for a sales price of $355 million subject to customary post-closing adjustments. Our undeveloped locations in the Piceance Basin were not included in the transaction, which was limited to a graduated working interest in certain of our proved developed producing wells drilled prior to 2009. The working interests represented approximately 300 Bcfe of proved reserves, or approximately 6 percent of our year-end 2013 proved reserves.

On August 18, 2014, we announced that we have agreed to sell our remaining mature, coalbed methane holdings in the Powder River Basin for $155 million in cash. We continue to negotiate the divestiture. The original sales agreement was scheduled to terminate February 13, 2015, but both parties agreed to extend the time table. If the agreement does not successfully close in March, WPX has the option to terminate the transaction. Additionally, we have recorded an impairment of $45 million in December 2014 to reduce the net assets to the probability weighted average of estimated sales prices that may be achieved. Reserves in the basin are estimated to be 200 Bcfe and fourth-quarter production was 143 MMcf per day, which includes operated and non-operated working interests in approximately 5,000 wells. Since 2011, our drilling activities in the basin have been minimal therefore resulting in declining production and production in the basin has amounted to less than 13 percent of our total domestic annual production in 2014. In our financial statements, we have reclassified our Powder River operations as discontinued operations in accordance with the provisions of “Presentation of Financial Statements” in the Accounting Standards Codification.

On August 26, 2014, we announced that we closed an agreement to jointly develop nearly 400 future wells in our Trail Ridge properties in the Piceance Basin with TRDC LLC, a subsidiary of Houston-based G2X Energy. As part of the joint agreement, we received $40 million in cash for 49 percent of our working interest in approximately 100 proved developed producing Trail Ridge wells in the Piceance Basin. During the carry period we will pay 28 percent of the Trail Ridge development and receive 51 percent of the production and reserves until TRDC has completed its $170 million funding commitment. The joint development agreement is for the Williams Forks and Iles formations and does not include deeper opportunities in the Mancos and Niobrara shales.

On January 29, 2015, we announced that we had completed the disposition of our international interests upon the successful merger of Apco Oil and Gas International Inc. (“Apco”) with a subsidiary of privately held Pluspetrol Resources Corporation. We received approximately $294 million for the disposition of our 69 percent controlling equity interest in Apco. In connection with the transaction, we also sold additional Argentina-related assets to Pluspetrol. Together, these non-operated international holdings comprised less than 5 percent of our 2014 year-end proved reserves. In our financial statements, we have reclassified our international operations to discontinued operations in accordance with the provision of “Presentation of Financial Statements” in the Accounting Standards Codification.

On February 2, 2015, we announced that we had completed the sale of our operations in northeast Pennsylvania, including the release of certain firm transportation capacity, to Southwestern Energy Company, for approximately $300 million. The transaction included physical operations covering approximately 46,700 acres, roughly 50 million cubic feet per day of net natural gas production, and 63 operated horizontal wells, primarily in Susquehanna County, Pennsylvania. The transfer in the firm transportation capacity in connection with the sale resulted in our release from approximately $24 million per year in annual demand obligations associated with the transport.

In 2014, we executed multiple transactions to control approximately 53,000 additional acres in the heart of the San Juan Basin’s Gallup oil window. These transactions included 28 Bcfe of proved reserves. 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. Prior to the divestiture in January 2015, we had international oil and gas producing activities, primarily in Argentina. Proved reserves related to international activities were less than 5 percent of our total international and domestic proved reserves as of December 31, 2014. 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, 2014, 2013 and 2012.

	As of December 31, 2014				
	Gas (MMcf)	Oil (Mbbls)	NGL (Mbbls)	Equivalent (MMcfe)	%
Proved Developed	2,089,974	60,012	43,955	2,713,770	62%
Proved Undeveloped	1,059,617	70,817	26,885	1,645,831	38%
Total Proved-Domestic	3,149,591	130,829	70,840	4,359,601	
	As of December 31, 2013				
	Gas (MMcf)	Oil (Mbbls)	NGL (Mbbls)	Equivalent (MMcfe)	%
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)	%
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	

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, 2014.

	As of December 31, 2014			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Equivalent (MMcfe)
Piceance Basin	2,162,071	7,649	54,430	2,534,548
Williston Basin	50,297	101,324	9,542	715,495
San Juan Basin	426,263	21,778	6,647	596,812
Appalachian Basin(a)	297,801	—	—	297,801
Powder River Basin(a)	200,089	—	—	200,089
Other	13,070	78	221	14,856
Total Proved-Domestic	3,149,591	130,829	70,840	4,359,601

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(a) Includes assets held for sale as of December 31, 2014 (see Note 2 and Note 4 of Notes to Consolidated Financial Statements).

We prepare our own reserves estimates and approximately 88 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 2014 year-end estimated proved reserves reflect an average natural gas price of $4.01 per Mcf, an average oil price of $83.62 per barrel and average NGL price of $40.40 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 2014, we added 691 Bcfe of extensions and discoveries to our proved reserves. During 2014, we participated in the drilling of 479 gross wells at a net capital cost of approximately $1,454 million, which includes costs associated with exploratory wells.

Proved reserves reconciliation

The 691 Bcfe of extensions and discoveries reflects 189 Bcfe added for drilled locations and 502 Bcfe added for new proved undeveloped locations. The extensions and discoveries were primarily in the Piceance, Williston and San Juan Basins. The acquisitions of 37 Bcfe were primarily in the San Juan Basin. The divestitures of 377 Bcfe were primarily in the Piceance Basin. The overall net negative revisions of 325 Bcfe reflects 97 Bcfe of net positive revisions made to developed reserves and 422 Bcfe of net negative 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. Reserves data analysis and further review are then 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 88 percent of our total year-end 2014 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 used to prepare the December 31, 2014 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, 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 32 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 fields where producing wells are less concentrated, generally 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, 2014, our proved undeveloped reserves were 1,646 Bcfe, a decrease of 338 Bcfe from our December 31, 2013 proved undeveloped reserves estimate of 1,984 Bcfe and represents 38 percent of our total proved reserves. During 2014, 394 Bcfe of our December 31, 2013 proved undeveloped reserves were converted to proved developed reserves at a cost of $592 million. This represents a proved undeveloped conversion rate of 19.9 percent. Of the converted reserves, 69 percent were in the Piceance Basin primarily in the Williams Fork formations, 25 percent were in the Bakken and Three Forks formations in the Williston Basin, and the other 6 percent were in all other production areas combined.

In 2014, net revisions for our proved undeveloped reserves were 422 Bcfe. Net negative revisions of 363 Bcfe were due to a reduction in near-term drilling capital estimates and the related limitations imposed by the SEC five year rules. Of the 363 Bcfe, 62 percent relates to the Piceance Basin, 17 percent relates to our San Juan Basin legacy assets, 11 percent in our Williston Basin assets and 10 percent for all other production areas. Net downward revision of 122 Bcfe is primarily due to re-spacing and field studies in the Piceance, Appalachian and Williston Basins. Revisions due to economics resulted in net upward revisions of 23 Bcfe. Revisions to proved undeveloped reserves that were on the books at December 31, 2013 and December 31, 2014 show an upward increase of 40 Bcfe.

All proved undeveloped locations are scheduled to be drilled within the next five years based on current expectations. Development drilling schedules are subject to revision and reprioritization throughout the year resulting from unknown factors such as the relative success of individual developmental drilling prospects, rig availability, title issues or delays and the effect that acquisitions or dispositions may have on prioritizing developmental drilling plans for maximizing returns of capital spent.

Oil and Gas Production, Production Prices and Production Costs
Production Sales Data
The following table summarizes our net production sales volumes, including those in the Appalachian Basin, for the years indicated, but excludes our Powder River Basin and international operations which are classified as discontinued operations.

	Year Ended December 31,		
	2014	2013	2012
Natural Gas (MMcf)			
U.S.			
Piceance Basin	205,853	219,317	246,179
Other	74,533	76,617	74,983
Total	280,386	295,934	321,162
Oil (Mbbls)			
U.S.			
Williston Basin	7,123	4,828	3,487
Other	2,121	1,091	907
Total	9,244	5,919	4,394
NGLs (Mbbls)			
U.S.			
Piceance Basin	5,352	6,963	10,075
Other	898	452	317
Total	6,250	7,415	10,392
Combined Equivalent Volumes (MMcfe)	373,352	375,940	409,877
Combined Equivalent Volumes (Mboe)	62,225	62,657	68,313
Average Daily Combined Equivalent Volumes (MMcfe/d)			
U.S.			
Piceance Basin	663	727	852
Other	360	303	268
Total	1,023	1,030	1,120

Net production sales data for our Powder River Basin and international operations are presented in the table below.

	Year Ended December 31,		
	2014	2013	2012
Natural Gas (MMcf)			
Powder River Basin	55,042	63,529	76,321
International	7,423	6,534	7,061
Total	62,465	70,063	83,382
Oil (Mbbls)			
Powder River Basin	1	8	—
International	2,142	2,032	2,178
Total	2,143	2,040	2,178
NGLs (Mbbls)			
Powder River Basin	—	6	—
International	160	167	181
Total	160	173	181
Combined Equivalent Volumes (MMcfe)	76,286	83,347	97,539
Combined Equivalent Volumes (Mboe)	12,714	13,891	16,257

Domestic realized average price per unit

The following table summarizes our domestic sales prices, including the Appalachian Basin, for the years indicated, but excludes our Powder River Basin operations which are classified as discontinued operations.

	Year Ended December 31,		
	2014	2013	2012
Natural gas(a):			
Natural gas excluding all derivative settlements (per Mcf)	$3.57	$3.01	$2.40
Impact of hedges (per Mcf)	—	0.02	1.32
Natural gas including hedges (per Mcf)	3.57	3.03	3.72
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)	(0.10)	(0.07)	0.04
Natural gas net price including all derivative settlements (per Mcf)	$3.47	$2.96	$3.76
Oil(a):			
Oil excluding all derivative settlements (per barrel)	$78.32	$90.21	$83.34
Impact of hedges (per barrel)	—	—	2.23
Oil including hedges (per barrel)	78.32	90.21	85.57
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	2.01	1.52	0.35
Oil net price including all derivative settlements (per barrel)	$80.33	$91.73	$85.92
NGL(a):			
NGL excluding all derivative settlements (per barrel)	$32.79	$30.72	$28.56
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	1.12	0.08	1.56
NGL net price including all derivative settlements (per barrel)	$33.91	$30.80	$30.12
Combined commodity price per Mcfe, including all derivative settlements	$5.17	$4.41	$4.55

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(a) Realized average prices reflect market prices, net of fuel, shrink, transportation and fractionation, and processing.

Domestic expenses per Mcfe

The following table summarizes our domestic costs, including costs in the Appalachian Basin, for the years indicated and excludes our Powder River Basin operations which are classified as discontinued operations.

	Year Ended December 31,		
	2014	2013	2012
Production costs:			
Lifting costs and workovers	$0.53	$0.47	$0.40
Facilities operating expense	0.06	0.07	0.04
Other operating and maintenance	0.06	0.06	0.05
Total LOE	$0.65	$0.60	$0.49
Gathering, processing and transportation charges	0.88	0.93	1.06
Taxes other than income	0.34	0.27	0.17
Total production cost	$1.87	$1.80	$1.72
General and administrative	$0.73	$0.71	$0.65
Depreciation, depletion and amortization	$2.17	$2.28	$2.16

Productive Oil and Gas Wells

The table below summarizes 2014 productive gross and net wells by area. 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.

	Gas Wells (Gross)	Gas Wells (Net)	Oil Wells (Gross)	Oil Wells (Net)
Piceance Basin	5,060	3,502	—	—
Williston Basin	—	—	196	138
San Juan Basin	3,174	875	90	82
Appalachian Basin(a)	168	87	—	—
Powder River Basin(a)	5,124	2,189	—	—
Other (b)	1,138	22	7	—
Total	14,664	6,675	293	220

(a) Includes assets held for sale as of December 31, 2014 (see Note 2 and Note 4 of Notes to Consolidated Financial Statements).

(b) Includes Green River Basin and other miscellaneous properties.

At December 31, 2014, there were 228 gross and 103 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2014.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance Basin	157,973	121,959	103,014	74,190	260,988	196,149
Williston Basin	64,419	56,760	68,199	28,723	132,618	85,483
San Juan Basin	239,404	130,485	94,587	80,656	333,991	211,141
Appalachian Basin(a)	37,970	27,995	65,069	51,547	103,038	79,541
Powder River Basin(a)	595,822	268,567	166,216	72,431	762,038	340,998
Other (b)	31,105	6,215	377,719	275,189	408,824	281,404
Total	1,126,693	611,981	874,804	582,736	2,001,497	1,194,716

(a) Includes assets held for sale as of December 31, 2014 (see Note 2 and Note 4 of Notes to Consolidated Financial Statements).

(b) Includes exploratory acreage in Montana, Wyoming, Kansas and other miscellaneous smaller properties.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was 100 percent in 2014, 2013 and 2012. Our combined development and exploration success rate was 99 percent in 2014, and 100 percent in 2013 and 2012.

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

	2014		2013		2012	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Development wells:						
Piceance Basin	267	250	249	236	239	208
Williston Basin	55	45	51	36	41	27
San Juan Basin	47	44	9	9	11	6
Appalachian Basin(a)	25	7	37	24	54	33
Powder River Basin(a)	61	22	37	16	150	92
Other(b)	17	—	24	—	52	—
Productive	472	368	407	321	547	366
Nonproductive	—	—	—	—	—	—
Development well total	472	368	407	321	547	366
Exploration wells:						
Productive	2	2	9	9	1	1
Nonproductive(c)	5	5	—	—	—	—
Exploration well total	7	7	9	9	1	1
Total Drilled	479	375	416	330	548	367

(a) Includes assets held for sale as of December 31, 2014 (see Note 2 and Note 4 of Notes to Consolidated Financial Statements).
(b) Includes Green River Basin and other miscellaneous properties.
(c) Reflects exploration wells which were drilled and not completed.

Total gross operated wells drilled were 369, 361 and 423 in 2014, 2013 and 2012, respectively.

Present Activities

At December 31, 2014, we had 12 gross (11 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

The table below sets forth, as of December 31, 2014, 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.

	2015	2016	2017	2018+	Total
Piceance Basin	777	5,782	14	11,746	18,319
Williston Basin	146	160	280	1,587	2,173
San Juan Basin	160	1,122	5,603	35,809	42,694
Appalachian Basin(a)	23,020	16,944	4,925	9,297	54,186
Powder River Basin(a)	660	39	1,640	27	2,366
Other(b)	54,135	62,131	132,469	93,085	341,820
Total (Gross Acres)	78,898	86,178	144,931	151,551	461,558

	2015	2016	2017	2018+	Total
Piceance Basin	396	4,966	14	10,865	16,241
Williston Basin	86	160	200	1,583	2,029
San Juan Basin	144	1,122	5,603	35,359	42,228
Appalachian Basin(a)	20,153	13,984	4,209	5,086	43,432
Powder River Basin(a)	342	19	820	14	1,195
Other(b)	43,987	46,363	89,103	83,583	263,036
Total (Net Acres)	65,108	66,614	99,949	136,490	368,161

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(a) Includes assets held for sale as of December 31, 2014 (see Note 2 and Note 4 of Notes to Consolidated Financial Statements).

(b) Includes Green River Basin and other miscellaneous properties.

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. 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 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. 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.

Purchase Commitments

In December 2010, we entered a long-term obligation to purchase 200,000 MMBtu per day 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 2014, natural gas sales to BP Energy Company accounted for approximately 13 percent of our consolidated revenues. We believe that the loss of one or more of our current natural gas, oil or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by 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 natural gas, oil, condensate 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.

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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 in areas where we operate for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and site restoration. 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 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 prorating provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Operation on Native American Reservations

A portion of our leases are, and some of our future leases may be, regulated by Native American tribes. In addition to regulation by various federal, state, and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and BLM, and the 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. 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, 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 provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants, 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. In particular, all of our wells that we drill and complete in our core assets such as Williston, Piceance and San Juan require hydraulic fracturing for production. 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 one-third 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 we perform baseline water monitoring required by the Colorado Oil and Gas Conservation Commission.
- The BLM may require baseline water monitoring as a condition of approval for drilling permits.
- 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 are pursuing options 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

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operations are performed to fill any voids and re-establish integrity. As part of this remedial operation, the casing is again pressure tested before fracturing operations are initiated.

- Initial casing integrity failure. The casing is pressure tested prior to commencing completion operations. If the test fails due to a compromise in the casing, the applicable oil and gas regulatory body will be notified and a remediation procedure will be written, approved and completed before any further operations are conducted. In addition, casing pressures are monitored throughout the fracturing treatment and any indication of failure will result in an immediate shutdown of the operation.
- Well failure or casing integrity failure during production. Loss of wellbore integrity can occur over time even if the well was correctly constructed due to downhole operating environments causing corrosion and stress. During production, the bradenhead, casing and tubing pressures are monitored and a casing failure can be identified and evaluated. Remediation could include placing additional cement behind casing, installing a casing patch, or plugging and abandoning the well, if necessary.
- "Fluid leakoff" during the fracturing process. Fluid leakoff can occur during hydraulic fracturing operations whereby some of the hydraulic fracturing fluid flows through the artificially created fractures into the micropore or pore spaces within the formation, existing natural 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, 2014, we have loaded data on more than 1,407 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 2014, 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 local 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") 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 in 2012, and the EPA issued its final guidance in February 2014. In September 2014, the EPA published its Final 2012 and Preliminary 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from on-shore Unconventional Oil and Gas Extraction and to discontinue establishing an effluent limitation guideline for the Coalbed Methane extraction industry. 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 2015, 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, Wyoming 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. In March 2014, the White House published the President's Climate Action Plan Strategy to Reduce Methane Emissions. 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.

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, 2014, we had approximately 1,100 full-time employees.

FINANCIAL INFORMATION ABOUT SEGMENTS

As of December 31, 2014, our operations included a domestic segment and an international segment. Our international segment is classified as discontinued operations for financial reporting purposes. See Item 8—Financial Statements and Supplementary Data—Consolidated Balance Sheets for the total assets of our domestic segment. See Item 8—Financial Statements and Supplementary Data—Consolidated Statements of Operations for revenues, and profits or losses of our domestic segment. See Item 8—Financial Statements and Supplementary Data— Note 2 of Notes to Consolidated Financial Statements for financial information with respect to our international segment's revenues, profits or losses, and total assets.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Item 8—Financial Statements and Supplementary Data—Consolidated Statements of Operations for amounts of revenues during the last three fiscal years from external customers attributable to the United States. See Item 8—Financial Statements and Supplementary Data—Note 2 of Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to all foreign countries. See Note 5 of Notes to Consolidated Financial Statements for information relating to Property, Plant and Equipment for the last two fiscal years, located in the United States and Note 2 for Property, Plant and Equipment for all foreign countries.

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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, 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."

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

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

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

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, 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 forward oil and natural gas prices in the fourth quarter of 2014, we performed assessments of our proved and unproved properties. As a result, we recorded impairments of capitalized costs of certain proved producing properties and costs of acquired unproved reserves of $20 million in 2014. 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 $3.8 billion of net book value associated with our predominantly natural gas proved properties and $2.7 billion of net book value associated with our predominantly oil proved properties and utilized inputs generally consistent with those described above. Many judgments and assumptions are inherent and to some extent interdependent of one another 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. 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 for which the operator is reasonably certain will commence 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 represents 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 38 percent of our total estimated proved reserves at December 31, 2014 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 reserves data included in the reserves 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 12 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 undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A portion of our acreage 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 San Juan 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, 2014 , we were not the operator of approximately 12 percent of our total net production. 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 requires that certain classes of swaps be cleared on a derivatives clearing organization unless an exemption to clearing is available to the parties to the swap. As of February 25, 2015, the Commodity Futures Trading Commission (the "CFTC") has designated only certain classes of interest rate swaps and index credit default swaps for mandatory clearing. While the swaps we currently use do not require clearing, it is unclear when the CFTC will designate other classes of swaps that we use, 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, and may cause increased costs to dealers that may be reflected in the pricing they make available to us. Moreover, certain of the transactions required to be cleared will have to be executed on boards of trade which may also adversely affect the pricing we are able to obtain.

The CFTC, the SEC and other regulators that oversee swap dealers have proposed regulations that may require us to post variation and/or initial margin. Posting of collateral could affect our liquidity, financial flexibility, and available cash. These regulations have not yet been finalized, however, and so it is difficult to predict the impact they will have on us.

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's original regulation setting position limits was vacated in September 2012 by the United States District Court for the District of Columbia. However, the CFTC recently proposed new position limits rules that would 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. The new position limit rules are not yet final and their impact on us is uncertain at this time.

Section 716 of the Dodd-Frank Act, commonly referred to as the "Swaps Pushout Rule," may also require certain of the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities. In December 2014, the President signed into law an amendment to Section 716 that reduced the impact of the pushout rule. Under the amended pushout rule, certain depository institutions will not be required to spin off their derivatives activities unless they are trading in a narrow class of swaps known as structured finance swaps. In the event that any of our counterparties are required to spin off their derivatives activities, the separate entities would be our counterparties in future swaps and may not be as creditworthy as our current counterparties.

The complete impact of the Dodd-Frank Act on our hedging activities is unknown 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, there is a risk that we might not satisfy the conditions to reliance on the end-user exception. Additionally, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. 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 as well as 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 additional cash or liquid collateral could also impact our liquidity, reduce cash available for capital expenditures and reduce our ability to execute hedges against commodity price uncertainty to 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 or 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 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 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, merge or sell substantially all of our assets, make investments, guarantees, loans or advances in non-subsidiaries, enter into certain hedging agreements, incur additional debt and enter into certain affiliate transactions. In addition, our credit facility contains financial covenants, including an additional financial covenant if our credit ratings drop below a specified level, and other limitations with which we will need to comply and which may limit our ability to borrow under the facility. Similarly, the

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indentures governing our senior notes restrict 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 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. 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 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. The rule requires annual reporting of GHG emissions by regulated facilities to the EPA. We are required to report our GHG emissions to the EPA each year in March under this rule, and the EPA publishes the data on its website. The EPA has also enacted permitting requirements for GHG emissions under the CAA for certain stationary sources and newer modification projects. In March 2014, the White House published the President’s Climate Action Plan Strategy to Reduce Methane Emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

The 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, the Obama administration announced on January 14, 2015, its interagency strategy to control methane emissions to reduce petroleum-sector methane emissions 40 to 45 percent by 2025 from 2012 levels. EPA plans to propose rules for new and modified wells in 2015 and finalize them in 2016. The Interior Department is to announce standards in the spring of 2015 aimed at reducing methane flaring at wells on federal land; the Department of Energy is to develop new ways to detect and repair methane leaks; the Department of Transportation is to develop new pipeline safety standards that also reduce leaks. In addition, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

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 2015. In September 2014, the EPA published its Final 2012 and Preliminary 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from on-shore unconventional oil and gas extraction and to discontinue establishing an effluent limitation guideline for the coalbed methane extraction industry. 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 September 2014, the EPA published its Final 2012 and Preliminary 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from on-shore unconventional oil and gas extraction and to discontinue establishing an effluent limitation guideline for the coalbed methane extraction industry. 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, 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 annually proposed changes to certain federal income tax provisions currently available to oil and gas exploration and production companies. The new chairmen of the House Ways & Means Committee and the Senate Finance Committee have also expressed their desire for business tax reform. Energy-related changes being discussed 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 Williams 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, then Williams and its stockholders could incur significant income tax liabilities, and we could incur significant liabilities.

Prior to our spin-off from Williams on December 31, 2011, Williams received 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. 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 a breach of any representations or covenants we made with respect to the spin-off and relied upon in the tax opinion or private letter ruling. The IRS is currently auditing Williams' 2011 consolidated federal income tax return that includes the spin-off.

We continue to be subject to the tax sharing agreement with Williams for the 2011 tax year.

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 with Williams, 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. 2011 is the only open federal tax period for which we are still subject to the tax sharing agreement with Williams. 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. We also have deferred tax assets that were allocated to us by Williams that could decrease or increase due to adjustments that change those allocations, whether or not related to our business. Williams effectively controls 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.

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:

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- 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 9 of our Notes to Consolidated Financial Statements for the information that is called for by this item.

In August 2014, we acquired acreage in New Mexico that includes historically operating wells. We are working with the New Mexico Air Quality Board to address violations of permitting requirements that occurred on this acreage prior to our acquisition, and we may be subject to fines in excess of $100,000 in connection with these violations.

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,			
	2014		2013	
	High	Low	High	Low
Common Stock:				
Fourth quarter	$24.42	$10.01	$23.69	$17.54
Third quarter	$26.79	$20.05	$20.36	$18.10
Second quarter	$24.35	$17.97	$21.11	$14.87
First quarter	$20.55	$16.80	$16.98	$14.03

At February 25, 2015, there were 8,099 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, 2014 and 2013, and for each of the three years in the period ended December 31, 2014, 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.

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Statement of operations data:	(Millions, except per share amounts)				
Revenues	$3,493	$2,431	$2,900	$3,531	$3,645
Income (loss) from continuing operations(a)	$129	$(1,104)	$(174)	$106	$(935)
Income (loss) from discontinued operations(b)	42	(87)	(37)	(398)	(348)
Net income (loss)	171	(1,191)	(211)	(292)	(1,283)
Less: Net income attributable to noncontrolling interests	7	(6)	12	10	8
Net income (loss) attributable to WPX Energy, Inc.	$164	$(1,185)	$(223)	$(302)	$(1,291)
Amounts attributable to WPX Energy, Inc.:					
Income (loss) from continuing operations	$129	$(1,092)	$(174)	$106	$(935)
Income (loss) from discontinued operations	$35	$(93)	$(49)	$(408)	$(356)
Basic earnings (loss) per common share:					
Income (loss) from continuing operations	$0.63	$(5.45)	$(0.87)	$0.54	$(4.75)
Income (loss) from discontinued operations	$0.18	$(0.46)	$(0.25)	$(2.07)	$(1.80)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	$0.62	$(5.45)	$(0.87)	$0.54	$(4.75)
Income (loss) from discontinued operations	$0.18	$(0.46)	$(0.25)	$(2.07)	$(1.80)

	As of December 31,				
	2014	2013	2012	2011	2010
Balance sheet data:	(Millions)				
Notes payable to Williams—current(c)	$—	$—	$—	$—	$2,261
Long-term debt	$2,280	$1,911	$1,501	$1,501	$—
Total assets	$8,798	$8,429	$9,456	$10,432	$9,846
Total stockholder's equity	$4,319	$4,109	$5,268	$5,678	$4,412
Total equity, including noncontrolling interests(c)	$4,428	$4,210	$5,371	$5,759	$4,484

(a) Income (loss) from continuing operations for the year ended December 31, 2014 includes approximately $87 million of impairment charges related to certain exploratory well costs, producing properties and costs of acquired unproved reserves. Income (loss) from continuing operations for the year ended December 31, 2013 includes $860 million of impairment charges primarily related to producing properties in the Appalachian Basin and costs of acquired unproved reserves in the 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 and $20 million impairment on our equity method investment. Income (loss) from continuing operations for the year ended December 31, 2012 includes $123 million of impairment charges related to producing properties in the Green River Basin and costs of acquired unproved reserves in the Piceance 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 4 of Notes to Consolidated Financial Statements for further discussion of the impairments in 2014, 2013 and 2012.

(b) Income (loss) from discontinued operations includes the results of Apco Oil and Gas International Inc., holdings in the Powder River Basin and holdings in the Barnett Shale and Arkoma Basin. Activity in 2014 includes a $45 million impairment charge related to the net assets held for sale in the Powder River Basin. Activity in 2013 reflects a $36 million gain on the sale of Powder River Basin deep rights leasehold. Activity in 2013, 2012 and 2011 reflects pre-tax impairment charges of $192 million, $102 million and $367 million, respectively, related to the Powder River Basin producing properties and costs of acquired unproved reserves. Activity in 2012 reflects a $38 million pre-tax gain recorded upon closing 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. See Note 2 of of Notes to Consolidated Financial Statements for further discussion of discontinued operations in 2014, 2013 and 2012.

(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, 2014 and 2013.

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 San Juan Basin and the Appalachian Basin in Pennsylvania. In addition, we have historically had operations in the Powder River Basin in Wyoming and a 69 percent controlling ownership interest in Apco Oil and Gas International Inc. ("Apco"), which has oil and gas activities in South America and, until January 29, 2015, traded on the NASDAQ Capital Market under the symbol "APAGF". As of December 31, 2014, Powder River Basin and Apco are reported as discontinued operations.

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 and oil, which include natural gas and oil purchased from working interest owners in operated wells and other area third-party producers. 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.

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

During January 2015, we completed the disposition of our international interests pursuant to the successful merger of Apco with a subsidiary of privately held Pluspetrol Resources Corporation ("Pluspetrol"). We received approximately $294 million for the disposition of our 69 percent controlling equity interest in Apco and additional Argentina-related assets to Pluspetrol. Together, these non-operated international holdings comprised our international segment. The results of operations of our international segment are reported as discontinued operations.

During the third quarter of 2014, we signed an agreement for the sale of our remaining mature, coalbed methane holdings in the Powder River Basin in Wyoming. As a result, we have reported the results of operations of the Powder River Basin as discontinued operations.

Also included in discontinued operations through second-quarter 2012, are results from our holdings in the Barnett Shale and the Arkoma Basin, which were sold in 2012.

See Note 2 of Notes to Consolidated Financial Statements for further discussion of our discontinued operations.
Unless indicated otherwise, the following discussion relates to continuing operations.

Overview

The following table presents our production volumes and financial highlights for 2014, 2013 and 2012:

	Years Ended December 31,		
	2014	2013	2012
Production Sales Volume Data(a):			
Natural gas (MMcf)	280,386	295,934	321,162
Oil (MBbls)	9,244	5,919	4,394
NGLs (MBbls)	6,250	7,415	10,392
Combined equivalent volumes (MMcfe)	373,352	375,940	409,877
Combined equivalent volumes (Mboe)	62,225	62,657	68,313
Production Sales Volume Per Day(a):			
Natural Gas (MMcf/d)	768	811	878
Oil (MBbls/d)	25	16	12
NGL (MBbls/d)	17	20	28
Combined equivalent volumes (MMcfe/d)	1,023	1,030	1,120
Financial Data (millions):			
Total revenues	$3,493	$2,431	$2,900
Operating income (loss)	$326	$(1,601)	$(157)
Cash capital expenditures(b)	$(1,807)	$(1,154)	$(1,521)

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(a) Excludes production from our discontinued operations.

(b) Includes capital expenditures related to discontinued operations of $96 million, $54 million and $79 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Our 2014 operating results were $1.9 billion favorable compared to 2013. Favorable impacts include a $558 million favorable change in derivatives not designated as hedges, a $250 million decrease in exploration expenses (including exploratory well costs and unproved leasehold impairments), $190 million higher oil and condensate sales and $106 million higher natural gas sales. Additionally, impairments of proved producing properties were $20 million in 2014 as compared to impairments of proved producing properties and capitalized cost of acquired unproved reserves of $860 million in 2013 (see Note 4 of Notes to Consolidated Financial Statements).

Our 2013 operating results were $1.4 billion unfavorable as compared to 2012. The primary unfavorable impact includes $860 million recorded in the fourth quarter 2013 for impairments of producing properties and costs of acquired unproved reserves as compared to $123 million of impairments recorded in 2012. Also included in 2013 is a $317 million impairment of related leasehold costs (see Note 4 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, $61 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 $181 million related to higher domestic realized natural gas prices (excluding hedges), $168 million from higher domestic oil production volumes and prices (excluding hedges), and $84 million lower gathering, processing and transportation costs.

Outlook

In October 2014, we announced a strategy to simplify our geographic focus and expand returns, margins and cash flow over the next five years. Key to this strategy are the core resource plays in North Dakota, New Mexico and Colorado. As a result, we will look to exit or scale back activities in our other areas. We have made significant progress toward this goal as evidenced by the completion of sales of our international interests to Pluspetrol and our operations in northeast Pennsylvania, including the release of certain firm transportation capacity, to Southwestern Energy Company. An agreement signed in the third quarter of 2014 for the sale of our coalbed methane assets in Wyoming has been extended as certain items are renegotiated due to current market conditions.

While the significant declines in forward commodity prices, especially oil, is challenging to the oil and gas industry as evidenced by the reduced 2015 capital plans among our peers and reductions in workforces across the industry, we are committed to our long term strategy. However, we will remain flexible to adjust to market conditions and prudent in preserving the strength of our balance sheet. For 2015, approximately three-fourths of our expected natural gas production and two-thirds of our expected oil production were hedged at prices above the current market which provides some protection to the price downturn. Our 2015 capital program is expected to be approximately $725 million, in line with our projected cash flow. Our drilling will be greatly reduced in 2015 as we plan to primarily drill locations that preserve leases or optimize the drilling rigs already under contract in an effort to reduce the impact of rig release penalties while potentially deferring completions. Additionally, as we reduce our areas of focus, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with growth objectives. We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities, and negotiating lower costs for vendor goods and services. Additionally, we continue to review our general and administrative costs and services.

In 2015, we will reduce our drilling activities in the Williston Basin in North Dakota and the Gallup Sandstone in the San Juan Basin in an effort to preserve those reserves for periods of higher oil prices. During 2014, we have added Gallup Sandstone acreage through acquisitions that brings the total we own or control to approximately 85,000 net acres. In 2015, we expect to spend $200 million to $225 million in the Williston Basin optimizing rigs already under contract ramping down to one rig by late spring for the balance of the year. We expect to spend $275 million to $300 million in the Gallup Sandstone, primarily preserving the leases and forming units. Despite the decrease in the capital expenditures in 2015, we are targeting a 15 to 20 percent growth in oil production.

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 expect to spend $200 million to $225 million in the Piceance Basin and plan to deploy an average of three and a half drilling rigs in the Piceance Basin for 2015, which includes drilling focused on the Niobrara Shale discussed below. Our drilling activity has primarily been focused in the Piceance Valley, however, we will start to shift more capital to opportunities in the Ryan Gulch field of the Piceance Basin where we have more than 4,000 drillable locations at 10-acre spacing.

A portion of our Piceance Basin estimated annual capital spending in 2015 will be for continued exploratory activities related to our Niobrara Shale discovery. Drilling thus far has validated the existence of a highly pressured continuous gas accumulation capable of producing pipeline-quality gas. However, as with most exploratory plays, our drilling and completion costs on initial wells have been higher relative to the reserves from these producing wells. As a result, we have recorded a $67 million impairment of the capitalized well costs. Future drilling will focus on driving down costs while optimizing completion techniques.

While market conditions are challenging for producers, opportunities may also arise that we will evaluate. Potential transactions to seize the opportunities may not serve to strengthen our balance sheet.

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 over the long-term;
- continuing to diversify our commodity portfolio through the development of our Williston Basin oil play position and Gallup Sandstone oil play and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- evaluating Niobrara Shale potential through drilling;
- continuing to pursue cost improvements and efficiency gains;
- employing new technology and operating methods;

- 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.

Changes in the forward prices will be considered as we proceed with our 2015 capital program. Additionally, if forecasted natural gas and oil prices were to decline we would need to review the producing properties net book value for possible impairment. See our discussion of impairment of long-lived assets in our critical accounting estimates discussion later in this section. 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 (see Note 14 of Notes to Consolidated Financial Statements). We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. We have the following contracts as of February 25, 2015 for approximately three-fourths of our anticipated 2015 natural gas production and approximately two-thirds of our anticipated 2015 oil production, shown at weighted average volumes and basin-level weighted average prices:

Natural Gas	2015		2016	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed-price—Henry Hub	442	$4.10	280	$3.81
Swaptions—Henry Hub	—	$—	90	$4.23
Costless Collars—Henry Hub	50	$ 4.00 - $4.50	—	$—
Basis swaps—NGPL	17	$(0.18)	—	$—
Basis swaps—San Juan	99	$(0.11)	—	$—
Basis swaps—Rockies	214	$(0.16)	—	$—
Basis swaps—SoCal	20	$0.18	—	$—
Crude Oil	2015		2016	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed-price—WTI	20,236	$94.88	—	$—
Swaptions—WTI	882	$97.29	5,250	$97.55

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. In conjunction with the closing of the Powder River sale and current terms therein, we may record certain pipeline capacity obligations associated with exiting the Powder River Basin. Our total commitments related to these pipeline agreements for 2015 and beyond total $172 million.

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Results of Operations

Operations of our company include natural gas, oil and NGL development, production and gas management activities primarily located in Colorado, New Mexico and North Dakota in the United States. Our development and production techniques specialize in production from tight-sands and shale formations primarily in the Piceance, Williston and San Juan 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.

2014 vs. 2013

Revenue Analysis

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2014	2013		
	(Millions)			
Domestic revenues:				
Natural gas sales	$1,002	$896	$106	12 %
Oil and condensate sales	724	534	190	36 %
Natural gas liquid sales	205	228	(23)	(10)%
Total product revenues	1,931	1,658	273	16 %
Gas management	1,120	891	229	26 %
Net gain (loss) on derivatives not designated as hedges	434	(124)	558	NM
Other	8	6	2	33 %
Total domestic revenues	$3,493	$2,431	$1,062	44 %

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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:

- $106 million increase in natural gas sales primarily reflects $157 million related to higher natural gas prices partially offset by a $47 million decrease related to lower production sales volumes for 2014 compared to 2013. The decrease in our production sales volumes is primarily due to the impact of the sale of a portion of our working interests to Legacy during second-quarter 2014 (see Note 4 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 73 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for 2014 and 2013:

	Years ended December 31,	
	2014	2013
Natural gas sales (per Mcf)(a)	$ 3.57	$ 3.03
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(b)	(0.10)	(0.07)
Natural gas net price including all derivative settlements (per Mcf)	$ 3.47	$ 2.96
Natural gas production sales volumes (MMcf)	280,386	295,934
Per day natural gas production sales volumes (MMcf/d)	768	811

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(a) Includes $0.02 per Mcf impact of net cash received on derivatives designated as hedges for 2013.

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

- $190 million increase in oil and condensate sales reflects a $300 million increase related to production sales volumes for 2014 compared to 2013 partially offset by a $110 million decrease related to lower sales prices. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin where the volumes were 19.5 MBbls per day for 2014 compared to 13.2 MBbls per day for 2013. The San Juan Basin also had production of 3.9 MBbls per day for 2014 related to the Gallup Sandstone development. The following table reflects oil and condensate production prices and volumes for 2014 and 2013:

	Years ended December 31, 2014	2013
Oil sales (per barrel)	$ 78.32	$ 90.21
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	2.01	1.52
Oil net price including all derivative settlements (per barrel)	$ 80.33	$ 91.73
Oil and condensate production sales volumes (MBbls)	9,244	5,919
Per day oil and condensate production sales volumes (MBbls/d)	25.3	16.2

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

- $23 million decrease in natural gas liquids sales reflects decreased production sales volumes despite a higher price per barrel for 2014 compared to 2013. The increased average barrel price for natural gas liquids partially 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 natural gas liquid production prices and volumes for 2014 and 2013:

	Years ended December 31, 2014	2013
NGL sales (per barrel)	$ 32.79	$ 30.72
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	1.12	0.08
NGL net price including all derivative settlements (per barrel)	$ 33.91	$ 30.80
NGL production sales volumes (MBbls)	6,250	7,415
Per day NGL production sales volumes (MBbls/d)	17.1	20.3

(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 2014 and 2013:

	Years ended December 31, 2014 % of barrel		$/gallon	2013 % of barrel		$/gallon
Ethane	29	%	$0.28	39	%	$0.25
Propane	33	%	$1.05	29	%	$0.98
Iso-Butane	10	%	$1.25	8	%	$1.41
Normal Butane	8	%	$1.22	7	%	$1.38
Natural Gasoline	20	%	$1.99	17	%	$2.11

- $229 million increase in gas management revenues primarily due to higher average prices on physical natural gas sales. The higher natural gas prices reflect the benefit of an increase in natural gas prices at sales points utilizing contracted pipeline capacity in the Northeast primarily during the first quarter of 2014. The increase in the sales

price was greater than the increase in the purchase price as reflected in the $56 million increase in related gas management costs and expenses, discussed below.

- $558 million favorable change in net gain (loss) on derivatives not designated as hedges primarily reflects a $565 million favorable change in unrealized gains (losses) on derivatives related to production, primarily natural gas and crude, and $100 million favorable change in the unrealized portion of gas management derivatives. Our net derivative assets as of December 31, 2014 were $494 million, of which 93 percent is expected to be recognized in the next 12 months. The favorable changes are partially offset by a $120 million of realized losses in 2014 on gas management derivatives.

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

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2014	2013		
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$244	$227	$(17)	(7)%
Gathering, processing and transportation	328	350	22	6%
Taxes other than income	126	102	(24)	(24)%
Gas management, including charges for unutilized pipeline capacity	987	931	(56)	(6)%
Exploration	173	423	250	59%
Depreciation, depletion and amortization	810	858	48	6%
Impairment of producing properties and costs of acquired unproved reserves	20	860	840	98%
Loss on sale of working interests in the Piceance Basin	196	—	(196)	NM
General and administrative	271	269	(2)	(1)%
Other—net	12	12	—	—%
Total domestic costs and expenses	$3,167	$4,032	$865	21%
Domestic operating income (loss)	$326	$(1,601)	$1,927	NM

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:

- $17 million increase in lease and facility operating expenses primarily relates to the impact of increased oil production in the Williston and San Juan Basins in relation to our overall portfolio. Lease and facility operating expense in 2014 averaged $0.65 per Mcfe compared to $0.60 per Mcfe during 2013.
- $22 million decrease in gathering, processing and transportation expenses primarily related to lower volumes and approximately $5 million recognized during 2014 related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. Also included in gathering, processing and transportation expenses are $13 million and $12 million in 2014 and 2013, respectively, of excess gathering capacity expense. Gathering, processing and transportation charges averaged $0.88 per Mcfe for 2014 and $0.93 per Mcfe for 2013. Excluding the impact of the refund, the gathering, processing and transportation expenses would have averaged $0.89 per Mcfe for 2014.
- $24 million increase in taxes other than income primarily relates to increased oil production volumes and higher natural gas prices. Our taxes other than income averaged $0.34 per Mcfe for 2014 compared to an average of $0.27 per Mcfe for 2013.
- $56 million increase in gas management expenses, primarily due to higher average prices on physical natural gas cost of sales. Additionally, in 2014 we recognized a loss of approximately $14 million on the release of future storage capacity commitments and approximately $4 million loss on the sale of related natural gas in storage partially offset

by $11 million related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. Also included in gas management expenses are $57 million and $61 million in 2014 and

2013, respectively, for unutilized pipeline capacity. Gas management expenses in 2013 also included $9 million related to the buyout of a transportation contract.

- $250 million decrease in exploration expenses primarily reflects lower unproved leasehold impairment, amortization and expiration expenses in 2014 compared to 2013. The unproved leasehold impairment in 2014 includes $41 million of impairments for unproved leasehold costs in exploratory areas where the company no longer intends to continue exploration activities, while 2013 includes a $317 million impairment to fair value of leasehold in the Appalachian Basin. The decrease in unproved leasehold impairment, amortization and expiration expenses was partially offset by a $67 million impairment related to our Niobrara Shale in the Piceance Basin and $16 million of impairments in other exploratory areas where management has determined to cease exploratory activities (see Note 4 of Notes to Consolidated Financial Statements).
- $48 million decrease in depreciation, depletion and amortization expenses primarily due to the previously discussed lower natural gas production volumes and the impact of impairments taken in 2013 in the Appalachian Basin partially offset by the increase in oil production. During 2014, our depreciation, depletion and amortization averaged $2.17 per Mcfe compared to an average $2.28 per Mcfe in 2013.
- $20 million of property impairments in 2014 compared to $860 million in 2013 (see Note 4 of Notes to Consolidated Financial Statements).
- $196 million loss on the sale of a portion of our working interests in certain Piceance Basin wells (see Note 4 of Notes to Consolidated Financial Statements).
- General and administrative expenses were relatively flat in 2014 compared to 2013. Included in 2014 is $10 million related to a voluntary early exit program.
- Other expenses include rig release and standby fees of $16 million and $12 million for 2014 and 2013, respectively.

Consolidated results below operating income (loss)

	Years ended December 31, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$326	$(1,601)	$1,927	NM
Interest expense	(123)	(108)	(15)	(14)%
Investment income, impairment of equity method investment and other	1	(19)	20	NM
Income (loss) from continuing operations before income taxes	204	(1,728)	1,932	NM
Provision (benefit) for income taxes	75	(624)	(699)	NM
Income (loss) from continuing operations	129	(1,104)	1,233	NM
Income (loss) from discontinued operations	42	(87)	129	NM
Net income (loss)	171	(1,191)	1,362	NM
Less: Net income (loss) attributable to noncontrolling interests	7	(6)	13	NM
Net income (loss) attributable to WPX Energy, Inc.	$164	$(1,185)	$1,349	NM

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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 during 2014 compared to 2013 and the $500 million of notes issued in the third quarter of 2014.

Our investment income, impairment of equity method investment and other in 2013 includes a $20 million impairment related to an equity method investment in the Appalachian Basin.

The provision (benefit) for income taxes changed unfavorably due to income from continuing operations before income taxes in 2014 compared to a loss from continuing operations before income taxes in 2013. See Note 8 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 includes the results of operations from Powder River Basin and our international segment (see Note 2 of Notes to Consolidated Financial Statements).

2013 vs. 2012
Revenue Analysis

	Years ended December 31, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic revenues:				
Natural gas sales	$896	$1,193	$(297)	(25)%
Oil and condensate sales	534	376	158	42%
Natural gas liquid sales	228	297	(69)	(23)%
Total product revenues	1,658	1,866	(208)	(11)%
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	$2,431	$2,900	$(469)	(16)%

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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:

- $297 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 $61 million related to lower production sales volumes partially offset by $181 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 increased over prior year. Natural gas production from the Piceance Basin represented approximately 74 percent of our total domestic natural gas production in 2013. 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)	$ 3.01	$ 2.40
Impact of hedges (per Mcf)	0.02	1.32
Natural gas sales including hedges (per Mcf)	$ 3.03	$ 3.72
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)(a)	(0.07)	0.04
Natural gas net price including all derivative settlements (per Mcf)	$ 2.96	$ 3.76
Natural gas production sales volumes (MMcf)	295,934	321,162
Per day natural gas production sales volumes (MMcf/d)	811	878

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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	$ 83.34
Impact of hedges (per barrel)	—	2.23
Oil sales including hedges (per barrel)	$ 90.21	$ 85.57
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	$ 85.92
Oil and condensate production sales volumes (MBbls)	5,919	4,394
Per day oil and condensate production sales volumes (MBbls/d)	16.2	12.0

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

- $69 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)	$ 30.72	$ 28.56
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)(a)	0.08	1.56
NGL net price including all derivative settlements (per barrel)	$ 30.80	$ 30.12
NGL production sales volumes (MBbls)	7,415	10,392
Per day NGL production sales volumes (MBbls/d)	20.3	28.4

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(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.

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

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2013	2012		
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$227	$202	$(25)	(12)%
Gathering, processing and transportation	350	434	84	19%
Taxes other than income	102	68	(34)	(50)%
Gas management, including charges for unutilized pipeline capacity	931	996	65	7%
Exploration	423	71	(352)	NM
Depreciation, depletion and amortization	858	884	26	3%
Impairment of producing properties and costs of acquired unproved reserves	860	123	(737)	NM
General and administrative	269	265	(4)	(2)%
Other—net	12	14	2	14%
Total domestic costs and expenses	$4,032	$3,057	$(975)	(32)%
Domestic operating income (loss)	$(1,601)	$(157)	$(1,444)	NM

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:

- $25 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 $0.60 per Mcfe for 2013 compared to $0.49 per Mcfe in 2012.
- $84 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 $0.93 per Mcfe compared to $1.06 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 $1.04 per Mcfe for 2012.
- $34 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 $0.17 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 periods 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.
- $26 million decrease in depreciation, depletion and amortization primarily due to lower production volumes in 2013 compared to 2012. Also during 2013, we adjusted our proved reserves used for the calculation of depletion and amortization which resulted in a net $11 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 $2.28 per Mcfe compared to an average $2.16 per Mcfe in 2012. This increase partially reflects the growth of the Williston Basin as part of our portfolio.
- $860 million in 2013 of impairments of producing properties and cost of acquired unproved reserves compared to $123 million for 2012, as previously discussed (see Note 4 of Notes to Consolidated Financial Statements).
- $4 million higher general and administrative expense is primarily due to $4 million of costs associated with the separation of our chief executive officer in 2013. General and administrative expense averaged $0.71 per Mcfe compared to $0.65 per Mcfe for 2013 and 2012, respectively.
- Other expenses include rig release and standby fees of $12 million and $9 million for 2013 and 2012, respectively.

Consolidated results below operating income (loss)

	Years ended December 31, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$(1,601)	$(157)	$(1,444)	NM
Interest expense	(108)	(102)	(6)	(6)%
Investment income, impairment of equity method investment and other	(19)	1	(20)	NM
Income (loss) from continuing operations before income taxes	(1,728)	(258)	(1,470)	NM
Provision (benefit) for income taxes	(624)	(84)	540	NM
Income (loss) from continuing operations	(1,104)	(174)	(930)	NM
Income (loss) from discontinued operations	(87)	(37)	(50)	(135)%
Net income (loss)	(1,191)	(211)	(980)	NM
Less: Net income (loss) attributable to noncontrolling interests	(6)	12	(18)	NM
Net income (loss) attributable to WPX Energy, Inc.	$(1,185)	$(223)	$(962)	NM

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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, impairment of equity method investment and other primarily reflects equity earnings associated with our 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 Note 4 of Notes to Consolidated Financial Statements).

Provision (benefit) for income taxes changed favorably primarily due to a greater loss from continuing operations before income taxes for 2013 compared to 2012. See Note 8 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 includes the results of operations from Powder River Basin and our international segment (see Note 2 of Notes to Consolidated Financial Statements).

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.

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Management's Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

In 2014, 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. In consideration of our liquidity, we note the following:

- As of December 31, 2014, 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.

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 2015 are expected cash flows from operations, proceeds from monetization of assets, and, if necessary, additional borrowings on our $1.5 billion credit facility. We anticipate that the combination of these sources will be sufficient to allow us to pursue our business strategy and goals for 2015.

We note the following assumptions for 2015:

- our cash capital expenditures are estimated to be approximately $875 million in 2015 and exceeds the previously mentioned $725 million of capital expenditures due to costs incurred in 2014 that will be paid in 2015. The new spending is generally considered to be largely discretionary; and
- We have hedged approximately three-fourths of our anticipated 2015 natural gas production at a weighted average price of $4.10 per MMbtu, and approximately two-thirds of anticipated 2015 oil production at a weighted average price of $94.88 per barrel.

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.

In October 2014, we amended and restated our $1.5 billion five-year senior unsecured revolving credit facility agreement with Citibank, N.A., as Administrative Agent, Lender and Swingline Lender and the other lender party thereto (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. The Credit Facility Agreement matures on October 28, 2019. As of December 31, 2014, the weighted average variable interest rate was 3.01 percent on the $280 million outstanding under the Credit Facility Agreement. As of February 25, 2015, we did not have any outstanding borrowings under the Credit Facility Agreement as proceeds from asset sales were used to repay all outstanding amounts. See Note 7 of Notes to Consolidated Financial Statements for discussion of significant terms related to the Credit Facility Agreement. The financial covenants in the Credit Facility Agreement that are described below may limit our ability to borrow money, depending on the applicable financial metrics at any given time.

Under the Credit Facility Agreement when our long-term unsercured debt rating is not BBB- or better by S&P or Baa3 or better by Moody’s and not less than BB+ by S&P or Ba1 by Moody's, we will be required to maintain a ratio of Consolidated Net Indebtedness (as defined in the Credit Facility Agreement) to Consolidated EBITDAX (as defined in the Credit Facility Agreement) of not greater than 3.75 to 1.00. Consolidated Net Indebtedness includes a reduction attributable to unrestricted cash and cash equivalents not to exceed $50 million. Consolidated EBITDAX will be calculated for the four fiscal quarters ending on the last day of any fiscal quarter for which financial statements have been or were required to be delivered. Additionally, the ratio of Consolidated Indebtedness (defined as Indebtedness of us and our consolidated subsidiaries determined on a consolidated basis) to Consolidated Total Capitalization (defined as Consolidated Indebtedness plus Consolidated Net Worth) will not be permitted to be greater than 60 percent and will be applicable for the life of the agreement.

When our long-term unsecured debt rating is BB or worse by S&P and Ba2 or worse by Moody’s or BB- or worse by S&P or Ba3 or worse by Moody’s, we will also be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the Credit Facility Agreement, to Consolidated Indebtedness ratio of at least 1.25 to 1.00 for fiscal periods ending on or prior to December 31, 2015, and 1.50 to 1.00 for fiscal periods ending after December 31, 2015. Based on our current long-term unsecured debt ratings, as of the date of this filing, we are not required to comply with this covenant. In addition, this covenant will not apply at any time after the occurrence of the Investment Grade Date, which is the first date after closing on which our long-term unsecured debt is rated BBB- or better by S&P or Baa3 or better by Moody’s (without negative outlook or watch by either agency), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody’s.

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, 2014, a total of $320 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

(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,		
	2014	2013	2012
	(Millions)		
Net cash provided (used) by:			
Operating activities	$1,070	$636	$796
Investing activities	(1,437)	(1,111)	(1,204)
Financing activities	344	426	37
Increase (decrease) in cash and cash equivalents	$(23)	$(49)	$(371)

Operating activities

Our net cash provided by operating activities in 2014 increased from 2013 primarily due to higher operating results driven by higher average natural gas prices and increased oil production volumes. In addition, 2014 increased due to higher net gas management revenues and expenses as previously discussed.

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.

Total cash provided by operating activities related to discontinued operations was approximately $130 million, $92 million and $68 million for 2014, 2013 and 2012, respectively.

Investing activities

Significant items include expenditures for drilling and completion of approximately $1.4 billion, $1.0 billion and $1.2 billion in 2014, 2013 and 2012, respectively. Domestic land acquisitions were $297 million, $61 million and $107 million during 2014, 2013 and 2012, respectively. Included in land acquisitions for 2014 was approximately $150 million related to the purchase of oil and natural gas properties in the San Juan Basin (see Note 5 of Notes to Consolidated Financial Statements). In addition, capital expenditures for international operations were $85 million, $51 million and $59 million during 2014, 2013 and 2012, respectively.

During 2014, we received proceeds of $337 million for the sale of a portion of our working interests in certain Piceance Basin wells to Legacy (see Note 4 of Notes to Consolidated Financial Statements). In addition, we also received proceeds of approximately $50 million related to the sale of a portion of our working interests in the Piceance Basin as part of an agreement to farmout a portion of our Trail Ridge properties with TRDC, LLC, a subsidiary of G2X Energy (see Note 5 of Notes to Consolidated Financial Statements).

During 2013, we received proceeds of $36 million from the sale of deep rights leasehold in the Powder River Basin and in 2012 we received proceeds of $306 million from the sale of our holdings in the Barnett Shale and Arkoma Basin.

Financing activities

During 2014, we issued $500 million of senior unsecured notes at an interest rate of 5.25 percent. We used the proceeds from this offering to repay borrowings under our revolving credit facility and for related transaction fees and expenses (see Note 7 of Notes to Consolidated Financial Statements). Net cash provided by financing activities in 2014 includes $130 million of net payments on our credit facility.

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.

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, 2014 and December 31, 2013.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2014.

	2015	2016 – 2017	2018 – 2019	Thereafter	Total
	(Millions)				
Long-term debt, including current portion:					
Principal	$1	$400	$280	$1,600	$2,281
Interest	122	233	200	296	851
Operating leases and associated service commitments:					
Drilling rig commitments(a)	79	34	—	—	113
Other	10	17	13	16	56
Transportation and storage commitments(b)	177	311	264	389	1,141
Oil and gas activities(c)	106	128	66	60	360
Other	11	10	7	—	28
Other long-term liabilities, including current portion:					
Physical and financial derivatives(d)	227	501	483	1,068	2,279
Total continuing operations	733	1,634	1,313	3,429	7,109
Obligations related to discontinued operations (e)	27	43	22	22	114
Obligations related to assets held for sale (f)	30	48	13	—	91
Total obligations	$790	$1,725	$1,348	$3,451	$7,314

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

(b) Excludes additional commitments totaling $39 million associated with projects for which the counterparty has not yet begun construction.

(c) Includes gathering, processing and other oil and gas related services commitments. Excluded are liabilities associated with asset retirement obligations, which total $201 million as of December 31, 2014. 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.

(d) Includes $2.3 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, 2014, 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.

(e) Represents obligation assumed by or anticipated to be assumed by the purchaser. Excluded are liabilities associated with asset retirement obligations totaling $55 million as of December 31, 2014.

(f) Represents obligation assumed by or anticipated to be assumed by the purchaser. Excluded are liabilities associated with asset retirement obligations totaling $2 million as of December 31, 2014.

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 when higher oil and gas prices cause an increase in drilling activity in our areas of operation. Likewise, lower prices and reduced drilling activity may lower the costs of services and equipment.

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 estimates of 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 oil, natural gas and natural gas liquids forward prices during 2014 and most significantly in the fourth quarter, we assessed our proved properties for impairment using estimates of future cash flows. Significant judgments and assumptions are inherent in these assessments and include estimates of reserves quantities, estimates of future commodity prices (developed in consideration of market information, internal forecasts and published forward prices adjusted for locational basis differentials), drilling plans, expected capital and lease operating costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. 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 approximately $20 million of impairment charges in 2014. See Notes 4 and 13 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 at the time. These reviews included $3.8 billion of net book value associated with our predominantly natural gas proved properties and $2.7 billion of net book value associated with our predominantly oil proved properties, and utilized inputs generally consistent with those described above. Many judgments and assumptions are inherent and to some extent interdependent of one another 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. If the estimated revenues (only one of the many estimates involved) of the proved oil and gas properties reviewed but for which impairment charges were not recorded were lower by 8 to 10 percent, these properties could be at risk for impairment. Over 65 percent of our future production is in years 2020 and beyond.

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 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 derivative 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 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 93 percent of the value of our derivatives portfolio expiring in the next 12 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 includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in offsetting the cash flows attributed to the hedged risk. We also assessed whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal

and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur and the quantity of the forecasted transaction. In addition, we 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.

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 14 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 88 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 the historical 12 month weighted average price, 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 $72 million and $87 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.

Estimates of future commodity prices, which are utilized in our impairment analyses, consider market information including published forward oil and natural gas prices. The forecasted price information used in our impairment analyses is consistent with that generally used in evaluating our drilling decisions and acquisition plans. Prices for future periods impact the production economics underlying oil and gas reserve estimates. In addition, changes in the price of natural gas and oil also impact certain costs associated with our underlying production and future capital costs. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the estimated future commodity prices 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 totaled $332 million at December 31, 2014.

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 9 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 from alternative minimum tax credits. 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 our effective state deferred tax rate can change periodically based on changes in our operations. Our effective state deferred tax rate is based upon our current entity structure and the jurisdictions in which we operate.

See Note 8 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, 2014, 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, 2014, 93 percent of the fair value of our derivatives portfolio expires in the next 12 months and 100 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2014, 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, 2014, 2013 and 2012, 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 13 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, $1,100 million matures in 2022 and $500 million matures in 2024. Interest rates for each group are 5.25 percent, 6.00 percent and 5.25 percent, respectively. The aggregate fair value of the senior notes is $1,938 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, 2014, the weighted average variable interest rate was 3.01 percent on the $280 million outstanding under the Credit Facility Agreement. See Note 7 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 marketing 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 13 and 14 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 asset of $1 million at December 31, 2014 and a net liability of $1 million at December 31, 2013. The value at risk for contracts held for trading purposes was less than $1 million at December 31, 2014 and December 31, 2013.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $493 million at December 31, 2014 and a net liability of $64 million at December 31, 2013.

The value at risk for derivative contracts held for nontrading purposes was $16 million at December 31, 2014, and $19 million at December 31, 2013. During the year ended December 31, 2014, our value at risk for these contracts ranged from a high of $19 million to a low of $16 million. The decrease in value at risk from December 31, 2013 primarily reflects decreases in market prices on 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, 2014, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (2013). Based on our assessment, we concluded that, as of December 31, 2014, 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.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 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, 2014, 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, 2014 and 2013, 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, 2014 of WPX Energy, Inc. and our report dated February 26, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 26, 2015

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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 26, 2015

WPX Energy, Inc.
Consolidated Balance Sheets

	December 31, 2014	2013
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$41	$47
Accounts receivable, net of allowance of $6 million and $7 million as of December 31, 2014 and 2013, respectively	459	518
Deferred income taxes	—	49
Derivative assets	498	50
Inventories	45	66
Margin deposits	27	71
Assets classified as held for sale	773	92
Other	26	29
Total current assets	1,869	922
Properties and equipment, net (successful efforts method of accounting)	6,842	6,760
Derivative assets	38	7
Other noncurrent assets	49	740
Total assets	$8,798	$8,429
Liabilities and Equity		
Current liabilities:		
Accounts payable	$712	$634
Accrued and other current liabilities	177	167
Liabilities associated with assets held for sale	132	41
Customer margin deposits payable	—	55
Deferred income taxes	151	—
Derivative liabilities	37	110
Total current liabilities	1,209	1,007
Deferred income taxes	621	776
Long-term debt	2,280	1,911
Derivative liabilities	5	12
Asset retirement obligations	198	305
Other noncurrent liabilities	57	208
Contingent liabilities and commitments (Note 9)		
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; 203.7 million shares issued at December 31, 2014 and 201 million shares issued at December 31, 2013)	2	2
Additional paid-in-capital	5,562	5,516
Accumulated deficit	(1,244)	(1,408)
Accumulated other comprehensive income (loss)	(1)	(1)
Total stockholders' equity	4,319	4,109
Noncontrolling interests in consolidated subsidiaries	109	101
Total equity	4,428	4,210
Total liabilities and equity	$8,798	$8,429

See accompanying notes.

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WPX Energy, Inc.
Consolidated Statements of Operations

	Years Ended December 31,		
	2014	2013	2012
Revenues:	(Millions, except per share amounts)		
Product revenues:			
Natural gas sales	$1,002	$896	$1,193
Oil and condensate sales	724	534	376
Natural gas liquid sales	205	228	297
Total product revenues	1,931	1,658	1,866
Gas management	1,120	891	949
Net gain (loss) on derivatives not designated as hedges (Note 14)	434	(124)	78
Other	8	6	7
Total revenues	3,493	2,431	2,900
Costs and expenses:			
Lease and facility operating	244	227	202
Gathering, processing and transportation	328	350	434
Taxes other than income	126	102	68
Gas management, including charges for unutilized pipeline capacity	987	931	996
Exploration (Note 4)	173	423	71
Depreciation, depletion and amortization	810	858	884
Impairment of producing properties and costs of acquired unproved reserves (Note 4)	20	860	123
Loss on sale of working interests in the Piceance Basin (Note 4)	196	—	—
General and administrative	271	269	265
Other—net	12	12	14
Total costs and expenses	3,167	4,032	3,057
Operating income (loss)	326	(1,601)	(157)
Interest expense	(123)	(108)	(102)
Investment income, impairment of equity method investment and other	1	(19)	1
Income (loss) from continuing operations before income taxes	204	(1,728)	(258)
Provision (benefit) for income taxes	75	(624)	(84)
Income (loss) from continuing operations	129	(1,104)	(174)
Income (loss) from discontinued operations	42	(87)	(37)
Net income (loss)	171	(1,191)	(211)
Less: Net income (loss) attributable to noncontrolling interests	7	(6)	12
Net income (loss) attributable to WPX Energy, Inc.	$164	$(1,185)	$(223)
Amounts attributable to WPX Energy, Inc.:			
Income (loss) from continuing operations	$129	$(1,092)	$(174)
Income (loss) from discontinued operations	35	(93)	(49)
Net income (loss)	$164	$(1,185)	$(223)
Basic earnings (loss) per common share (Note 3):			
Income (loss) from continuing operations	$0.63	$(5.45)	$(0.87)
Income (loss) from discontinued operations	0.18	(0.46)	(0.25)
Net income (loss)	$0.81	$(5.91)	$(1.12)
Weighted-average shares (millions)	202.7	200.5	198.8
Diluted earnings (loss) per common share (Note 3):			
Income (loss) from continuing operations	$0.62	$(5.45)	$(0.87)

Income (loss) from discontinued operations	0.18	(0.46)	(0.25)
Net income (loss)	$0.80	$(5.91)	$(1.12)
Weighted-average shares (millions)	206.3	200.5	198.8

See accompanying notes.

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

	Years Ended December 31,		
	2014	2013	2012
	(Millions)		
Net income (loss) attributable to WPX Energy, Inc.	$164	$(1,185)	$(223)
Other comprehensive income (loss):			
Change in fair value of cash flow hedges, net of tax(a)	$—	$—	$57
Net reclassifications into earnings of net cash flow hedge gains, net of tax(b)	—	(3)	(274)
Other comprehensive income (loss), net of tax	—	(3)	(217)
Comprehensive income (loss) attributable to WPX Energy, Inc.	$164	$(1,188)	$(440)

(a) Change in fair value of cash flow hedges is net of income tax of $33 million for 2012. 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 14).

(b) Net reclassifications into earnings of net cash flow hedge realized gains are net of $2 million and $159 million of income tax for 2013 and 2012, respectively. Before tax amounts realized and reclassified to product revenues, primarily natural gas sales revenues, on the Consolidated Statements of Operations were $5 million and $434 million for 2013 and 2012, 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	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests(a)	Total
	(Millions)						
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
Comprehensive income:							
Net income (loss)	—	—	164		164	7	171
Other comprehensive income (loss)	—	—		—	—		—
Comprehensive income (loss)							171
Contribution from noncontrolling interest	—	—		—	—	1	1
Stock based compensation, net of tax benefit	—	46		—	46	—	46
Balance at December 31, 2014	$2	$5,562	$ (1,244)	$ (1)	$ 4,319	$ 109	$4,428

(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,		
	2014	2013	2012
Operating Activities	(Millions)		
Net income (loss)	$171	$(1,191)	$(211)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	863	940	973
Deferred income tax provision (benefit)	46	(645)	(160)
Provision for impairment of properties and equipment (including certain exploration expenses) and investments	236	1,483	288
Amortization of stock-based awards	36	32	28
(Gain) loss on sales of assets(a)	196	(41)	(42)
Cash provided (used) by operating assets and liabilities:			
Accounts receivable	51	(43)	68
Inventories	19	(5)	7
Margin deposits and customer margin deposits payable	(10)	(18)	(5)
Other current assets	8	(7)	7
Accounts payable	4	41	(128)
Accrued and other current liabilities	(1)	(21)	12
Changes in current and noncurrent derivative assets and liabilities	(559)	106	(32)
Other, including changes in other noncurrent assets and liabilities	10	5	(9)
Net cash provided by operating activities	1,070	636	796
Investing Activities			
Capital expenditures(b)	(1,807)	(1,154)	(1,521)
Proceeds from sales of assets	374	49	310
Other	(4)	(6)	7
Net cash used in investing activities	(1,437)	(1,111)	(1,204)
Financing Activities			
Proceeds from common stock	16	6	3
Proceeds from long-term debt			