WPX ENERGY, INC.
Form 10-Q
August 06, 2015

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

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

For the quarterly period ended June 30, 2015
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 (State or Other Jurisdiction of Incorporation or Organization)	45-1836028 (IRS Employer Identification No.)
3500 One Williams Center, Tulsa, Oklahoma (Address of Principal Executive Offices)	74172-0172 (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
6.25% Series A Mandatory Convertible Preferred Stock, $0.01 par value	New York Stock Exchange

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

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 þ 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 þ No ¨

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 þ	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 þ

The number of shares outstanding of the registrant's common stock at August 5, 2015 were 235,181,715.

WPX Energy, Inc.
Index

Certain matters contained in this report 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 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

2

- 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;
- other factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations"; and
- additional risks described in our filings with the Securities and Exchange Commission ("SEC").

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. For a detailed discussion of those factors, see Part II, Item 1A. Risk Factors in this filing and Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2014.

WPX Energy, Inc.
Consolidated Balance Sheets
(Unaudited)

	June 30, 2015	December 31, 2014
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$317	$ 41
Accounts receivable, net of allowance of $7 million as of June 30, 2015 and $6 million as of December 31, 2014	280	459
Derivative assets	260	498
Inventories	48	45
Margin deposits	7	27
Assets classified as held for sale	127	773
Other	28	26
Total current assets	1,067	1,869
Properties and equipment (successful efforts method of accounting)	12,158	11,753
Less—accumulated depreciation, depletion and amortization	(5,340)	(4,911)
Properties and equipment, net	6,818	6,842
Derivative assets	32	38
Other noncurrent assets	45	49
Total assets	$7,962	$ 8,798
Liabilities and Equity		
Current liabilities:		
Accounts payable	$339	$ 712
Accrued and other current liabilities	169	177
Liabilities associated with assets held for sale	47	132
Deferred income taxes	149	151
Derivative liabilities	26	37
Total current liabilities	730	1,209
Deferred income taxes	611	621
Long-term debt	2,000	2,280
Derivative liabilities	5	5
Asset retirement obligations	208	198
Other noncurrent liabilities	41	57
Contingent liabilities and commitments (Note 8)		
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; 205.2 million shares issued at June 30, 2015 and 203.7 million shares issued at December 31, 2014)	2	2
Additional paid-in-capital	5,572	5,562
Accumulated deficit	(1,207)	(1,244)
Accumulated other comprehensive income (loss)	—	(1)
Total stockholders' equity	4,367	4,319
Noncontrolling interests in consolidated subsidiaries	—	109
Total equity	4,367	4,428

Total liabilities and equity	$7,962	$ 8,798

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Operations
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Revenues:	(Millions, except per-share amounts)			
Product revenues:				
Natural gas sales	$127	$262	$294	$579
Oil and condensate sales	145	194	262	343
Natural gas liquid sales	25	54	48	115
Total product revenues	297	510	604	1,037
Gas management	57	231	215	792
Net gain (loss) on derivatives (Note 10)	(71)	(17)	34	(212)
Other	1	3	3	4
Total revenues	284	727	856	1,621
Costs and expenses:				
Lease and facility operating	51	59	108	119
Gathering, processing and transportation	69	78	142	167
Taxes other than income	19	33	41	68
Gas management, including charges for unutilized pipeline capacity	59	233	168	624
Exploration (Note 4)	6	54	13	69
Depreciation, depletion and amortization	227	202	443	395
Net (gain) loss on sales of assets (Note 4)	(209)	—	(278)	—
Loss on sale of working interests in the Piceance Basin	—	195	—	195
General and administrative	63	70	127	137
Other—net	5	1	31	3
Total costs and expenses	290	925	795	1,777
Operating income (loss)	(6)	(198)	61	(156)
Interest expense	(32)	(28)	(65)	(57)
Investment income and other	1	—	2	—
Income (loss) from continuing operations before income taxes	(37)	(226)	(2)	(213)
Provision (benefit) for income taxes	(14)	(82)	(1)	(69)
Income (loss) from continuing operations	(23)	(144)	(1)	(144)
Income (loss) from discontinued operations	(7)	11	39	30
Net income (loss)	(30)	(133)	38	(114)
Less: Net income (loss) attributable to noncontrolling interests	—	2	1	3
Comprehensive income (loss) attributable to WPX Energy, Inc.	$(30)	$(135)	$37	$(117)
Amounts attributable to WPX Energy, Inc.:				
Income (loss) from continuing operations	$(23)	$(144)	$(1)	$(144)
Income (loss) from discontinued operations	(7)	9	38	27
Net income (loss)	$(30)	$(135)	$37	$(117)
Basic and diluted earnings (loss) per common share (Note 3):				
Income (loss) from continuing operations	$(0.12)	$(0.71)	$(0.01)	$(0.71)
Income (loss) from discontinued operations	(0.02)	0.05	0.19	0.13
Net income (loss)	$(0.14)	$(0.66)	$0.18	$(0.58)
Weighted-average shares (millions)	205.0	202.7	204.6	202.1

See accompanying notes.

5

WPX Energy, Inc.
Consolidated Statements of Changes in Equity
(Unaudited)

	WPX Energy, Inc., Stockholders					Noncontrolling Interests in Consolidated Subsidiaries (a)	Total Equity
	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity		
	(Millions)						
Balance at December 31, 2014	$2	$5,562	$(1,244)	$(1)	$4,319	$109	$4,428
Comprehensive income (loss):							
Net income (loss)	—	—	37	—	37	1	38
Comprehensive income (loss)							38
Stock based compensation	—	10	—	—	10	—	10
Impact of divestitures				1	1	(110)	(109)
Balance at June 30, 2015	$2	$5,572	$(1,207)	$—	$4,367	$—	$4,367

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

WPX Energy, Inc.
Consolidated Statements of Cash Flows
(Unaudited)

	Six months ended June 30, 2015	2014
	(Millions)	
Operating Activities		
Net income (loss)	$38	$(114)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	443	422
Deferred income tax provision (benefit)	(17)	(78)
Provision for impairment of properties and equipment (including certain exploration expenses)	26	66
Amortization of stock-based awards	20	17
(Gain) loss on sales of international interests and domestic assets	(318)	195
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	176	34
Inventories	(2)	(9)
Margin deposits and customer margin deposits payable	21	(26)
Other current assets	(4)	15
Accounts payable	(145)	1
Accrued and other current liabilities	(33)	(20)
Changes in current and noncurrent derivative assets and liabilities	233	27
Other, including changes in other noncurrent assets and liabilities	(8)	(10)
Net cash provided by operating activities	430	520
Investing Activities		
Capital expenditures(a)	(679)	(728)
Proceeds from sale of international interests and domestic assets	772	338
Other	2	(5)
Net cash provided by (used in) investing activities	95	(395)
Financing Activities		
Proceeds from common stock	2	12
Borrowings on credit facility	181	904
Payments on credit facility	(461)	(1,024)
Other	—	(6)
Net cash provided by (used in) financing activities	(278)	(114)
Net increase (decrease) in cash and cash equivalents	247	11
Effect of exchange rate changes on cash and cash equivalents	—	(5)
Cash and cash equivalents at beginning of period(b)	70	99
Cash and cash equivalents at end of period	$317	$105

(a) Increase to properties and equipment	$(435)	$(760)
Changes in related accounts payable and accounts receivable	(244)	32
Capital expenditures	$(679)	$(728)

(b) For periods prior to sale, amounts include cash associated with our international operations and represents the difference between amounts reported as cash on the Consolidated Balance Sheet.

See accompanying notes.

WPX Energy, Inc.
Notes to Consolidated Financial Statements
Note 1. Basis of Presentation and Description of Business
Description of Business
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. We specialize in development and production from tight-sands and shale formations in the Piceance, Williston and San Juan Basins. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. 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 and related derivatives, coupled with the sale of our commodity volumes.
In addition, we have operations in the Powder River Basin in Wyoming that are classified as held for sale and, until January 29, 2015, we had a 69 percent controlling interest in Apco Oil and Gas International Inc. (“Apco”), an oil and gas exploration and production company with activities in Argentina and Colombia. For all periods presented, the results of Powder River Basin and Apco are reported as discontinued operations.
The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as “WPX” or the “Company,” is at times referred to in the first person as “we,” “us” or “our”.
Basis of Presentation
The accompanying interim consolidated financial statements do not include all the notes included in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto for the year ended December 31, 2014 in the Company’s Annual Report on Form 10-K. The accompanying interim consolidated financial statements include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our financial position at June 30, 2015, results of operations for the three and six months ended June 30, 2015 and 2014, changes in equity for the six months ended June 30, 2015 and cash flows for the six months ended June 30, 2015 and 2014.
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.
Our continuing operations are comprised of a single business segment, which includes the development, production and gas management activities of natural gas, oil and NGLs in the United States. Prior to classifying our international operations as discontinued operations, we reported business segments for domestic and international.
Discontinued Operations
On January 29, 2015, we completed the disposition of our international interests and received net proceeds of $291 million after expenses but before $17 million of cash on hand at Apco as of the closing date. The results of operations of our international segment have been reported as discontinued operations on the Consolidated Statements of Operations and the assets and liabilities have been classified as held for sale on the Consolidated Balance Sheet as of December 31, 2014.
The results of operations of the Powder River Basin have also been reported as discontinued operations on the Consolidated Statements of Operations and the assets and liabilities have been classified as held for sale on the Consolidated Balance Sheets.
See Note 2 for a further discussion of discontinued operations. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations. Additionally, see Note 8 for a discussion of contingencies related to Williams’ former power business (most of which was disposed of in 2007).
Recently Issued Accounting Standards
In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The core principles of the guidance in ASU 2014-09 are that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the impact, if any, of ASU 2014-09 to the Company's financial position, results of operations or cash flows.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern, to provide guidance on management's responsibility in evaluating whether there is substantial doubt about a company's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The Company does not expect the adoption of ASU 2014-15 to have a significant impact on its Consolidated Financial Statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. The core principles of the guidance in ASU 2015-03 require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the guidance in this update. ASU 2015-03 is effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company does not believe the adoption of this guidance will have a material impact on its financial position, results of operations or cash flows. As of June 30, 2015, we have $26 million in debt issuance costs.

Note 2. Discontinued Operations

On October 3, 2014, we announced an agreement to sell our international interests for approximately $294 million subject to the successful consummation of the definitive merger agreement entered into between Pluspetrol Resources Corporation and Apco. On January 29, 2015 we completed this divestiture and received net proceeds of $291 million after expenses but before $17 million of cash on hand at Apco as of the closing date. These non-operated international holdings comprised our international segment. We recorded a pretax gain of $41 million related to this transaction during first quarter 2015.

During the third quarter of 2014, our management signed an agreement to sell our remaining mature, coalbed methane holdings in the Powder River Basin for $155 million. This sales agreement did not successfully close in March 2015 and we subsequently terminated the transaction with the counterparty. Subsequent to June 30, 2015, we signed agreements for the sale of the Powder River Basin holdings (See Note 11). During the first half of 2015, we recorded a total of $16 million in impairments of the net assets to a probability weighted-average of expected sales prices. The Powder River operations have firm gathering and treating agreements with total commitments of $110 million through 2020. These commitments have been in excess of our production throughput. We also have certain pipeline capacity obligations held by our marketing company with total commitments for 2015 and thereafter totaling $155 million. Depending on the final terms upon closing a Powder River sale, we may record a portion of these obligations if they meet the definition of exit activities in association with exiting the Powder River Basin.

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

Summarized Results of Discontinued Operations

	Three months ended June 30, 2015	Three months ended June 30, 2014		
	Powder River Basin	Powder River Basin	International	Total
	(Millions)			
Total revenues	$17	$48	$39	$87
Costs and expenses:				
Lease and facility operating	$7	$10	$8	$18
Gathering, processing and transportation	14	18	1	19
Taxes other than income	1	2	7	9
Exploration	—	—	3	3
Depreciation, depletion and amortization	—	4	9	13
Impairment of assets held for sale	6	—	—	—
General and administrative	—	1	3	4
Other—net	1	—	2	2
Total costs and expenses	29	35	33	68
Operating income (loss)	(12)	13	6	19
Interest capitalized	—	1	—	1
Investment income and other	1	—	5	5
Income (loss) from discontinued operations before income taxes	(11)	14	11	25
Provision (benefit) for income taxes	(4)	7	7	14
Income (loss) from discontinued operations	$(7)	$7	$4	$11

	Six months ended June 30, 2015		
	Powder River Basin	International	Total
		(Millions)	
Total revenues	$42	$15	$57
Costs and expenses:			
Lease and facility operating	$17	$4	$21
Gathering, processing and transportation	28	—	28
Taxes other than income	4	3	7
Impairment of assets held for sale	16	—	16
General and administrative	1	1	2
Other—net	—	—	—
Total costs and expenses	66	8	74
Operating income (loss)	(24)	7	(17)
Investment income and other	3	1	4
Gain on sale of international assets	—	41	41
Income (loss) from discontinued operations before income taxes	(21)	49	28
Provision (benefit) for income taxes (a)	(8)	(3)	(11)
Income (loss) from discontinued operations	$(13)	$52	$39

(a) International includes the reversal of certain U.S. deferred tax liabilities associated with Apco.

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

	Six months ended June 30, 2014		
	Powder River Basin	International	Total
		(Millions)	
Total revenues	$110	$70	$180
Costs and expenses:			
Lease and facility operating	$21	$16	$37
Gathering, processing and transportation	35	1	36
Taxes other than income	8	13	21
Exploration	—	3	3
Depreciation, depletion and amortization	8	19	27
General and administrative	2	7	9
Other—net	—	3	3
Total costs and expenses	74	62	136
Operating income (loss)	36	8	44
Interest capitalized	1	—	1
Investment income and other	2	7	9
Income (loss) from discontinued operations before income taxes	39	15	54
Provision (benefit) for income taxes	15	9	24
Income (loss) from discontinued operations	$24	$6	$30

Assets and Liabilities in the Consolidated Balance Sheet Attributable to Discontinued Operations

As of June 30, 2015, the following table presents assets classified as held for sale and liabilities associated with assets held for sale related to our Powder River Basin operations.

	June 30, 2015
	Total
	(Millions)
Assets classified as held for sale	
Current assets:	
Inventories	$1
Total current assets	1
Investments	18
Properties and equipment, net(a)	108
Total assets classified as held for sale on the Consolidated Balance Sheets	$127
Liabilities associated with assets held for sale	
Current liabilities:	
Accrued and other current liabilities	$3
Total current liabilities	3
Asset retirement obligations	44
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	$47

(a) Includes a cumulative total of $61 million in impairments of the net assets held for sale of the Powder River Basin.

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

As of December 31, 2014 the following table presents domestic assets classified as held for sale and liabilities associated with assets held for sale related to our Powder River Basin and Appalachian Basin operations, and the international assets classified as held for sale and liabilities associated with assets held for sale related to our international operations which were divested in January 2015.

	December 31, 2014		
	Domestic	International	Total
		(Millions)	
Assets classified as held for sale			
Current assets:			
Cash and cash equivalents	$—	$29	$29
Accounts receivable	—	25	25
Inventories	1	7	8
Other	—	14	14
Total current assets	1	75	76
Investments	18	134	152
Properties and equipment, net(a)	122	217	339
Other noncurrent assets	—	6	6
Total assets classified as held for sale—discontinued operations	$141	$432	$573
Total assets classified as held for sale—continuing operations (Note 4)	200	—	200
Total assets classified as held for sale on the Consolidated Balance Sheets	$341	$432	$773
Liabilities associated with assets held for sale			
Current liabilities:			
Accounts payable	$—	$34	$34
Accrued and other current liabilities	3	23	26
Total current liabilities	3	57	60
Deferred income taxes	—	13	13
Long-term debt	—	2	2
Asset retirement obligations	45	7	52
Other noncurrent liabilities	—	3	3
Total liabilities associated with assets held for sale—discontinued operations	$48	$82	$130
Total liabilities associated with assets held for sale—continuing operations (Note 4)	$2	$—	$2
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	$50	$82	$132

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(a) Domestic includes a total of $45 million in impairments of the net assets held for sale of the Powder River Basin.

Cash Flows Attributable to Discontinued Operations
Excluding income taxes and changes to working capital, total cash used by operating activities related to the Powder River Basin was $6 million for the six months ended June 30, 2015 and total cash provided by operating activities was $48 million for the six months ended June 30, 2014. Total cash used in investing activities related to Powder River Basin discontinued operations was $3 million and $7 million for the six months ended June 30, 2015 and 2014, respectively. Cash provided by operating activities related to our international operations was $3 million and $19 million for the six months ended June 30, 2015 and 2014, respectively. Total cash used in investing activities related

our international operations was $15 million and $36 million for the six months ended June 30, 2015 and 2014, respectively.

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

Note 3. Earnings (Loss) Per Common Share from Continuing Operations

The following table summarizes the calculation of earnings per share.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(Millions, except per-share amounts)			
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$(23)	$(144)	$(1)	$(144)
Basic weighted-average shares	205.0	202.7	204.6	202.1
Diluted weighted-average shares(a)	205.0	202.7	204.6	202.1
Earnings (loss) per common share from continuing operations:				
Basic	$(0.12)	$(0.71)	$(0.01)	$(0.71)
Diluted	$(0.12)	$(0.71)	$(0.01)	$(0.71)

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

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(Millions)			
Weighted-average nonvested restricted stock units and awards	1.7	2.4	1.7	2.5
Weighted-average stock options	0.1	1.1	0.1	1.0

The table below includes information related to stock options that were outstanding at June 30, 2015 and 2014 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the second quarter weighted-average market price of our common shares.

	June 30,	
	2015	2014
Options excluded (millions)	2.0	0.1
Weighted-average exercise price of options excluded	$17.42	$21.45
Exercise price range of options excluded	$13.46 - $21.81	$21.45 - $21.45
Second quarter weighted-average market price	$13.18	$21.27

For the six months ended June 30, 2015, approximately 1.0 million nonvested restricted stock units were antidilutive and were excluded from the computation of diluted weighted-average shares.

Note 4. Asset Sales, Other Expenses and Exploration Expenses

Asset Sales

During May 2015, WPX completed the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast for approximately $209 million in cash. The transaction released WPX from various long-term natural gas purchase and sales obligations and approximately $390 million in future demand payment obligations associated with the transport position. As a result of this transaction, we recorded a net gain of $209 million in second-quarter 2015 on these executory contracts.

During the first quarter of 2015, we sold a portion of our Appalachian Basin operations and released certain firm transportation capacity to Southwestern Energy Company (NYSE: SWN) for approximately $288 million, subject to post closing adjustments. Including an estimate of post closing adjustments, we recorded a net gain of $69 million in first-quarter 2015. This transaction included physical operations covering approximately 46,700 acres, roughly 50 MMcfe per day of net natural gas production and 63 horizontal wells. The assets were primarily located in the Appalachian Basin in Susquehanna County, Pennsylvania. The transaction also included the release of firm transportation capacity that we had under contract in the

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

Northeast, primarily 260 MMcfe per day with Millennium Pipeline. Upon the transfer of the firm capacity, we were released from approximately $24 million per year in annual demand obligations associated with the transport.
During the second quarter of 2014, we completed the sale of a portion of our working interests in certain Piceance Basin wells. Based on an estimated total value received at closing of $329 million which represented estimated final cash proceeds and an estimated fair value of incentive distribution rights we received, we recorded a $195 million loss on the sale for the three and six months ended June 30, 2014.

Other Expenses

During the first quarter of 2015, we executed a termination and settlement agreement to release us from a crude oil transportation and sales agreement in anticipation of entering into a different agreement with another third party with more favorable terms. As a result of this contract termination and settlement, we recorded an expense of approximately $22 million which is included in Other—net on the Consolidated Statements of Operations.

Exploration Expenses

The following table presents a summary of exploration expenses.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(Millions)			
Geologic and geophysical costs	$1	$3	$2	$7
Dry hole costs and impairments of exploratory area well costs	—	15	—	15
Unproved leasehold property impairment, amortization and expiration	5	36	11	47
Total exploration expenses	$6	$54	$13	$69

Dry hole costs and impairments of exploratory area well costs for the three and six months ended June 30, 2014 includes $10 million of impairments of well costs in an exploratory area in the United States where management had determined to cease exploratory activities. The remaining amount represents dry hole costs associated with exploratory wells in the United States where hydrocarbons were not detected.
Included in unproved leasehold property impairment, amortization and expiration for the three and six months ended June 30, 2014, are impairments totaling $26 million for unproved leasehold costs in two exploratory areas where the Company no longer intends to continue exploration activities.
As of June 30, 2015, our total capitalized well costs associated with our exploratory areas, including the Niobrara Shale in the Piceance Basin, totaled approximately $76 million.

Note 5. Inventories

The following table presents a summary of our inventories as of the dates indicated below.

	June 30, 2015	December 31, 2014
	(Millions)	
Material, supplies and other	$48	$43
Crude oil production in transit	—	2
Total inventories	$48	$45

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

Note 6. Debt and Banking Arrangements
The following table presents a summary of our debt as of the dates indicated below.

	June 30, 2015	December 31, 2014
	(Millions)	
5.250% Senior Notes due 2017	$400	$400
6.000% Senior Notes due 2022	1,100	1,100
5.250% Senior Notes due 2024	500	500
Credit facility agreement	—	280
Other	1	1
Total debt	$2,001	$2,281
Less: Current portion of long-term debt	1	1
Total long-term debt	$2,000	$2,280

Senior Notes
See Note 11 for a discussion of $1 billion in senior notes which were issued subsequent to June 30, 2015 and our Annual Report on Form 10-K for the year ended December 31, 2014 for a discussion of our previously issued senior notes.
Credit Facility
We have a $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 lenders party thereto (the “Credit Facility”). Under the terms of the Credit Facility 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 matures on October 28, 2019. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of June 30, 2015, we were in compliance with our financial covenants and had full access to the Credit Facility. For additional information regarding the terms of our Credit Facility prior to recent amendments, see our Annual Report on Form 10-K for the year ended December 31, 2014. See Note 11 for a discussion of recent amendments to our Credit Facility and increases in the commitments from existing banks subsequent to June 30, 2015.
Letters of Credit
WPX has also entered into three bilateral, uncommitted letter of credit (“LC”) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility. At June 30, 2015, a total of $233 million in letters of credit have been issued.
Note 7. Provision (Benefit) for Income Taxes
The following table presents the provision (benefit) for income taxes from continuing operations.

	Three months ended June 30, 2015	2014	Six months ended June 30, 2015	2014
	(Millions)			
Current:				
Federal	$—	$11	$—	$12
State	—	2	—	2
	—	13	—	14
Deferred:				
Federal	(13)	(85)	(1)	(86)
State	(1)	(10)	—	3
	(14)	(95)	(1)	(83)
Total provision (benefit)	$(14)	$(82)	$(1)	$(69)

The effective tax rate for all periods presented above differs from the federal statutory rate primarily due to the effects of state income taxes.

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

As a result of the sale of Apco in the first quarter of 2015, we no longer have foreign operations and the associated tax liabilities. The closing of Apco resulted in a $42 million capital loss for which a valuation allowance was established in 2014.

Tax reform legislation was enacted by the state of New York on March 31, 2014, and had an impact on us as a result of our marketing activities in the state. As a result, we recorded an additional $9 million of deferred tax expense in the first quarter of 2014 to accrue for the impact of this new legislation.

As of June 30, 2015, the amount of unrecognized tax benefits is not material. During the next 12 months, we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of our unrecognized tax benefit.

Pursuant to our tax sharing agreement with The Williams Companies, Inc. ("Williams"), we remain responsible for the tax from audit adjustments related to our business for periods prior to the spin-off. In addition, the alternative minimum tax credit deferred tax asset that was allocated to us by Williams at the time of the spin-off could change due to audit adjustments unrelated to our business. The 2011 consolidated tax filing by Williams is currently being audited by the IRS and is the only pre spin-off period for which we continue to have exposure to audit adjustments as part of Williams. It is uncertain when the IRS will complete that audit.

Note 8. Contingent Liabilities

Royalty litigation

In September 2006, royalty-interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County, Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for proceeds received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments related to calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class for certification, resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim related to the issue of whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. Plaintiffs had claimed damages of approximately $20 million plus interest for the period from July 2000 to July 2008. The court issued pretrial orders finding that we do bear the burden of demonstrating enhancement of the value of gas in order to deduct transportation costs and that the enhancement test must be applied on a monthly basis in order to determine the reasonableness of post-production transportation costs. Trial occurred in December 2013 on the issue of whether we have met that burden. Following that trial, the court issued its order rejecting plaintiffs' proposed standard and accepting our position as to the methodology to use in determining the standard by which our activity should be judged. We have completed the accounting process under the standard and have obtained the court's approval. However, as we continue to believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law, we have appealed this matter to the Colorado Court of Appeals. Plaintiffs have now filed a second class action lawsuit in the District Court, Garfield County containing similar allegations but related to subsequent time periods. The parties have agreed to stay this new lawsuit pending resolution of the first lawsuit in the Colorado Court of Appeals.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint presently alleges failure to pay royalty on hydrocarbons including drip condensate, breach of the duty of good faith and fair dealing, fraudulent concealment, conversion, misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons in Colorado, violation of the New Mexico Oil and Gas Proceeds Payment Act, and bad faith breach of contract. Plaintiffs sought monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter was removed to the United States District Court for New Mexico. In March 2015, the court denied plaintiffs' motion for class certification. Plaintiffs have not timely filed an appeal of this denial. They have filed both a pending motion for reconsideration of the denial of class certification with the trial court which we oppose and a motion seeking to conduct additional discovery in order to attempt to redefine their proposed class, which has been denied. In August 2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico and violation of the New Mexico Oil and Gas Proceeds Payment Act, and seek declaratory judgment, accounting and injunction. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we are monitoring them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue ("ONRR") in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. The ONRR's guidance provides its view as to how much of a producer's bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states though such guidelines are expected in the future. However, the timing of any such guidance is uncertain and, independent of the issuance of additional guidance, ONRR asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR's assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR's predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From July 2008 through June 2015, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $115 million.

Environmental matters

The Environmental Protection Agency ("EPA"), other federal agencies, and various state and local regulatory agencies and jurisdictions routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, new air quality standards for ground level ozone, methane, green completions, and hydraulic fracturing and water standards. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matter related to Williams' former power business

In connection with a Separation and Distribution Agreement between WPX and Williams, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us for the pending litigation described below relating to the reporting of certain natural gas-related information to trade publications.

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, seeking unspecified amounts of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin and brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs' lack of standing. On January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal and entered judgment in our favor. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs' state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. The plaintiffs appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion in the Western States Antitrust Litigation holding that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims and reversing the summary judgment previously entered in favor of the defendants. The U.S. Supreme Court granted Defendants' writ of certiorari. On April 21, 2015, the U.S. Supreme Court determined that the state antitrust claims are not preempted by the federal Natural Gas Act. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time.

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

Other Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At June 30, 2015, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In connection with the separation from Williams, we agreed to indemnify and hold Williams harmless from any losses resulting from the operation of our business or arising out of liabilities assumed by us. Similarly, Williams has agreed to indemnify and hold us harmless from any losses resulting from the operation of its business or arising out of liabilities assumed by it.

Summary

As of June 30, 2015 and December 31, 2014, the Company had accrued approximately $16 million for loss contingencies associated with royalty litigation and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

Note 9. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, restricted cash, and margin deposits and customer margin deposits payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	June 30, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$9	$282	$1	$292	$14	$517	$5	$536
Energy derivative liabilities	$13	$17	$1	$31	$32	$10	$—	$42
Total debt(a)	$—	$1,961	$—	$1,961	$—	$2,218	$—	$2,218

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(a) The carrying value of total debt, excluding capital leases, was $2,000 million and $2,280 million as of June 30, 2015 and December 31, 2014, respectively.

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

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, option and swaption contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars or as swaptions and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us. Significant inputs into our Level 2 valuations include commodity prices, implied volatility and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with 100 percent of the net fair value of our derivatives portfolio expiring at the end of 2016. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes or market indications and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 were a net liability of less than $1 million at June 30, 2015, and consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers occurred during the periods ended June 30, 2015 and 2014.

There have been no material changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Note 10. Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas, oil and natural gas liquids attributable to commodity price risk.

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

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements and financial option contracts to mitigate the price risk associated with these contracts. Derivatives for transportation contracts economically hedge the expected cash flows generated by those agreements.

19

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

Derivatives related to production
The following table sets forth the derivative notional volumes that are economic hedges of production volumes, which are included in our commodity derivatives portfolio as of June 30, 2015.

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Natural Gas					
Natural Gas	Jul-Dec 2015	Fixed Price Swaps	Henry Hub	(410)	$4.05
Natural Gas	Jul-Dec 2015	Costless Collars	Henry Hub	(50)	$ 4.00 - 4.50
Natural Gas	Jul-Dec 2015	Basis Swaps	NGPL	(20)	$(0.18)
Natural Gas	Jul-Dec 2015	Basis Swaps	Rockies	(280)	$(0.17)
Natural Gas	Jul-Dec 2015	Basis Swaps	San Juan	(108)	$(0.11)
Natural Gas	Jul-Dec 2015	Basis Swaps	SoCal	(50)	$0.08
Natural Gas	2016	Fixed Price Swaps	Henry Hub	(280)	$3.81
Natural Gas	2016	Swaptions	Henry Hub	(90)	$4.23
Natural Gas	2017	Swaptions	Henry Hub	(65)	$4.19
Crude Oil					
Crude Oil	Jul -Dec 2015	Fixed Price Swaps	WTI	(18,500)	$94.75
Crude Oil	2016	Fixed Price Swaps	WTI	(15,500)	$61.86
Crude Oil	2016	Swaptions	WTI	(8,500)	$84.27

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(a) Derivatives related to crude oil production are fixed price swaps settled on the business day average and swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, swaptions and costless collars. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us.
(b) Natural gas volumes are reported in BBtu/day and crude oil volumes are reported in Bbl/day.
(c) The weighted average price for natural gas is reported in $/MMBtu and the crude oil price is reported in $/Bbl.

Derivatives primarily related to transportation
The following table sets forth the derivative notional volumes of the net long (short) positions of derivatives primarily related to transportation contracts, which are included in our commodity derivatives portfolio as of June 30, 2015. The weighted average price is not reported since the notional volumes represent a net position comprised of buys and sells with positive and negative transaction prices.

Commodity	Period	Contract Type (a)	Location (b)	Notional Volume (c)
Natural Gas	Jul-Dec 2015	Fixed Price Swaps	Multiple	(4)
Natural Gas	Jul-Dec 2015	Basis Swaps	Multiple	(1)
Natural Gas	Jul-Dec 2015	Index	Multiple	(51)

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(a) We enter into exchange traded fixed price and basis swaps, over-the-counter fixed price and basis swaps, physical fixed price transactions and transactions with an index component.
(b) We transact at multiple locations primarily around our core assets to maximize the economic value of our transportation and asset management agreements.
(c) Natural gas volumes are reported in BBtu/day.

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

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheets as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	June 30, 2015		December 31, 2014	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production	$282	$17	$517	$10
Derivatives related to physical marketing agreements	10	14	19	32
Total derivatives	$292	$31	$536	$42

We enter into commodity derivative contracts that serve as economic hedges but are not designated as cash flow hedges for accounting purposes as we do not utilize this method of accounting on derivative instruments. The following table presents the net gain (loss) related to our energy commodity derivatives.

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
	(Millions)			
Gain (loss) from derivatives related to production (a)	$(68)	$(24)	$54	$(110)
Gain (loss) from derivatives related to physical marketing agreements (b)	(3)	7	(20)	(102)
Net gain (loss) on derivatives not designated as hedges	$(71)	$(17)	$34	$(212)

(a) Includes receipts totaling $137 million and payments totaling $16 million for settlements of derivatives during the three months ended June 30, 2015 and 2014, respectively; and receipts totaling $295 million and payments totaling $66 million for the six months ended June 30, 2015 and 2014, respectively.

(b) Includes payments totaling $5 million and $1 million for settlements of derivatives during the three months ended June 30, 2015 and 2014, respectively; and payments totaling $28 million and $119 million for the six months ended June 30, 2015 and 2014, respectively.

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

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

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

June 30, 2015	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted (Received)	Net Amount
Derivative assets with right of offset or master netting agreements	$292	$(23)	$—	$269
Derivative liabilities with right of offset or master netting agreements	$(31)	$23	$4	$(4)
December 31, 2014				
Derivative assets with right of offset or master netting agreements	$536	$(25)	$—	$511
Derivative liabilities with right of offset or master netting agreements	$(42)	$25	$17	$—

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

Credit-risk-related features
Certain of our derivative contracts contain credit-risk-related provisions that would require us, under certain events, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor’s and/or Moody’s Investment Services. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability.

As of June 30, 2015, we had collateral totaling $6 million posted to derivative counterparties, which included $2 million of initial margin to clearinghouses or exchanges to enter into positions and $4 million of maintenance margin for changes in the fair value of those positions, to support the aggregate fair value of our net $8 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $4 million at June 30, 2015.

Concentration of Credit Risk
Cash equivalents
Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Derivative assets and liabilities
We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a

counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2015 and

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

2014, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

The following table presents the gross and net credit exposure from our derivative contracts as of June 30, 2015.

Counterparty Type	Gross Total	Net Total
	(Millions)	
Financial institutions (Investment Grade)(a)	$292	$269
Credit exposure from derivatives	$292	$269

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(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum S&P’s rating of BBB- or Moody’s Investors Service rating of Baa3 in investment grade.

Our eight largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

Other

Collateral support for our commodity agreements could include margin deposits, letters of credit and guarantees of payment by credit worthy parties.

Note 11. Subsequent Events

On July 13, 2015, we entered into a definitive merger agreement to acquire privately held RKI Exploration & Production, LLC ("RKI") for $2.75 billion, consisting of 40 million unregistered shares of WPX common stock and approximately $2.28 billion in cash (the "Acquisition"). The cash consideration is subject to closing adjustments and will be reduced by our assumption of $400 million of aggregate principal amount of RKI's senior notes and any amounts outstanding under RKI's revolving credit facility. RKI is engaged in the acquisition, exploration, development and production of oil and natural gas properties located onshore in the continental United States, concentrated primarily in the Permian Basin, and more specifically the Delaware Basin sub-area, which span parts of New Mexico and Texas. RKI also has oil and gas properties in the Powder River Basin. In connection with the Acquisition, RKI intends either (i) to contribute its Powder River Basin assets and other properties outside the Delaware Basin to a wholly owned RKI subsidiary, the ownership interests of which will be paid to RKI's equity holders in connection with the Acquisition, or (ii) to dispose of such assets in a third party sale.

The majority of RKI's Delaware Basin leasehold is located in Loving County, Texas and Eddy County, New Mexico. RKI's assets in the Permian Basin include approximately 92,000 net acres in the core of the Permian's Delaware Basin. RKI operates 659 gross producing wells in the Delaware Basin with an average working interest of approximately 93 percent. RKI's average net daily production from its Delaware Basin properties for the year ended December 31, 2014 was 18.7 MBoe per day, 43 percent of which was oil, 23 percent NGLs and 34 percent natural gas. RKI's average net daily production from its Delaware Basin properties for the three months ended March 31, 2015 was 18.5 MBoe per day, 52 percent of which was oil, 14 percent NGLs and 34 percent natural gas. As of December 31, 2014, RKI had proved reserves in the Delaware Basin of 101.5 MMBoe, 40 percent of which was oil, 25 percent NGLs and 35 percent natural gas.

WPX will fund the Acquisition with proceeds from a combination of debt, preferred stock and common stock offerings (as further described below in "Financing Transactions") along with available cash on hand and borrowings under its revolving credit facility. The parties expect to close the transaction by the end of third quarter 2015, subject to customary closing conditions.

Complete financials of RKI as of and for the period ended June 30, 2015 are not currently available to us. Certain unaudited pro forma condensed combined financial information and RKI financial statements as of March 31, 2015 and December 31, 2014 and the respective periods then ended are included in our Current Report on Form 8-K filed

July 14, 2015. The unaudited pro forma condensed combined financial information was presented for illustrative purposes based on the assumptions noted therein and do not represent what our results of operations or financial position would actually have been had the transactions noted therein occurred for those periods presented.

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

Financing Transactions

On July 22, 2015 we completed equity offerings of (a) 30,000,000 shares of our common stock (or 34,500,000 shares if the underwriters exercise their option to purchase additional shares in full) for gross proceeds of approximately $303 million (or approximately $348 million if the underwriters exercise their option to purchase additional shares in full) at the public offering price of $10.10 per share and (b) $350 million of aggregate liquidation preference of 6.25% series A mandatory convertible preferred stock (or $402.5 million of aggregate liquidation preference if the underwriters exercise their option to purchase additional shares in full). The underwriter's have 30 days from the date of these offerings to purchase additional shares.

On July 22, 2015, we completed our debt offering of (a) $500 million aggregate principal amount of 7.50% senior unsecured notes due 2020 (the "2020 Notes") and (b) $500 million aggregate principal amount of 8.25% senior unsecured notes due 2023 (the "2023 Notes").

The Notes are the Company's senior unsecured obligations ranking equally with the Company's other existing and future senior unsecured indebtedness. The 2020 Notes bear interest at a rate of 7.50% per annum, and the 2023 Notes bear interest at a rate of 8.25% per annum. Interest is payable on the Notes semiannually in arrears on February 1 and August 1 of each year commencing on February 1, 2016. The 2020 Notes will mature on August 1, 2020. The 2023 Notes will mature on August 1, 2023. At any time or from time to time prior to July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, the Company may, at its option, redeem the applicable series of Notes, in whole or in part, at a makewhole redemption price as set forth in the Indenture. The Company also has the option, at any time or from time to time on or after July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, to redeem some or all of the applicable series of Notes at a redemption price equal to 100% of the principal amount of the Notes to be redeemed, as more fully described in the Indenture. The Notes are also subject to a special mandatory redemption as more fully described in the Indenture if the Company's previously announced Acquisition is not consummated by, or the merger agreement related to such acquisition is terminated prior to, November 30, 2015. The Indenture contains covenants that, among other things, restrict the Company's ability to grant liens on its assets and merge, consolidate or transfer or lease all or substantially all of its assets, subject to certain qualifications and exceptions.

The table below reflects the pro forma impact of the financing transactions noted above, net of estimated expenses, to certain line items of our balance sheet as of June 30, 2015.

	June 30, 2015 As Reported	Financing Transaction Adjustments	Pro Forma After Adjustments
Cash and cash equivalents	$317	$1,608	$1,925
Total assets	$7,962	$1,631	$9,593
Total debt	$2,001	$1,000	$3,001
Equity:			
Preferred stock	$—	$339	$339
Common stock	2	—	2
Additional paid-in-capital	5,572	292	5,864
Accumulated deficit	(1,207)	—	(1,207)
Total equity	$4,367	$631	$4,998
Total liabilities and equity	$7,962	$1,631	$9,593

Amendments to Credit Facility and commitment increase

On July 16, 2015, the Company amended its senior unsecured revolving credit facility to, among other things (a) modify the financial covenants in a manner favorable to the Company in respect of (i) the ratio of PV to Consolidated Indebtedness and (ii) the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX and (b) add a financial covenant requiring a minimum ratio of Consolidated EBITDAX to Consolidated Interest Charges (each capitalized term used herein but not defined is defined in the Company's revolving credit facility, as amended).

Under the amended revolving credit facility, if the Company's Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody's or (b) B+ or worse by S&P or B1 or worse by Moody's, the Company will 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, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company's Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody's (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody's.

In addition, the Company is required to maintain a ratio of Consolidated Net Indebtedness to Consolidated EBITDAX of not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company's Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody's and not less than BB+ or Ba1 by the other such agency. The ratio of Consolidated Indebtedness to Consolidated Total Capitalization is not permitted to be greater than 60 percent and is applicable for the life of the agreement. Furthermore, the Company may not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.50 to 1.00.

Under the terms of the Credit Facility 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. On July 31, 2015, the commitments from existing lenders were increased by $250 million, for total commitments of $1.75 billion. Subsequent to June 30, 2015, we borrowed $200 million on the Credit Facility in anticipation of the Acquisition closing.

Powder River Divestiture Update

Subsequent to June 30, 2015, we signed agreements for the sale of our holdings in the Powder River Basin for $80 million, subject to closing adjustments such as net revenues from effective date to closing date. Based on estimated proceeds under this agreement, we expect to record a loss on sale of approximately $10 million to $20 million. Closing of this transaction is expected by the end of 2015. See Note 2 for a further discussion of Powder River operations including commitments related to certain pipeline capacity and firm gathering and treating agreements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

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 I, Item 1 in this Form 10-Q and our 2014 Annual Report on 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-Q and our Annual Report on Form 10-K.

On January 29, 2015, we completed the disposition of our international interests pursuant to the successful merger of Apco Oil and Gas International Inc. ("Apco") with a subsidiary of privately held Pluspetrol Resources Corporation. The results of Apco 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. This agreement did not successfully close in March 2015 and we subsequently terminated the transaction with the counterparty. However, management has continued to pursue the divestiture of these holdings. Subsequent to June 30, 2015, we have signed agreements for the sale of the Powder River Basin holdings (see Note 11 of Notes to Consolidated Financial Statements). As a result, we have reported the results of operations and financial position of the Powder River Basin as discontinued operations.

Unless indicated otherwise, the following discussion relates to continuing operations.

Overview

The following table presents our production volumes and financial highlights for the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Production Sales Data(a):				
Natural gas (MMcf)	61,388	71,972	124,865	143,503
Oil (MBbls)	2,975	2,159	6,092	3,896
NGLs (MBbls)	1,791	1,625	3,310	3,212
Combined equivalent volumes (MMcfe)(b)	89,985	94,680	181,276	186,155
Per day combined equivalent volumes (MMcfe/d)	989	1,040	1,002	1,028
Combined equivalent volumes (MBoe)(b)	14,998	15,780	30,213	31,026
Per day combined equivalent volumes (MBoe/d)	164.8	173.4	166.9	171.4
Financial Data (millions):				
Total revenues	$284	$727	$856	$1,621
Operating income (loss)	$(6)	$(198)	$61	$(156)
Cash capital expenditures(c)	$199	$376	$679	$728
Capital expenditure activity(c)	$138	$388	$435	$760

(a) Excludes production from our discontinued operations.

(b) MBoe and MMcfe are converted using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.

(c) Includes capital expenditures related to discontinued operations of $2 million and $20 million for the three months ended June 30, 2015 and 2014, respectively, and $18 million and $43 million for the six months ended June 30, 2015 and 2014, respectively.

Our second-quarter 2015 operating results were $192 million favorable compared to second-quarter 2014. The primary favorable impacts include a $209 million gain on the sale of a package of marketing contracts and release of certain related firm transportation capacity in 2015 while the three months ended June 30, 2014 included a $195 million loss on the sale of a portion of our working interests in the Piceance Basin. Additionally, exploration expenses for the three months ended June 30, 2015 were $48 million lower than the comparable period in 2014 primarily due to impairments in 2014 of exploratory leasehold well costs. The favorable impacts were partially offset by a $213 million decrease in product revenues primarily due to lower sales prices and a $54 million unfavorable change in net gain (loss) on derivatives for the three months ended June 30, 2015 compared to the same period in 2014.

Our year to date 2015 operating results were $217 million favorable compared to year to date 2014. The primary favorable impacts include $278 million net gain on sales of assets in 2015 (see Note 4 of Notes to Consolidated Financial Statements) while 2014 included a $195 million loss on the sale of a portion of our working interests in the Piceance Basin. Additional favorable impacts include a $246 favorable change in net gain (loss) on derivatives and $56 million lower exploration expense for year to date 2015 compared to 2014. The favorable impacts were partially offset by $433 million decrease in product revenues primarily due to lower sales prices and $121 million lower net gas management margin.

Outlook

As previously disclosed, our strategy is 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. We made significant progress toward simplifying our geographic focus with the completion of the sales of our international interests in Argentina and a significant portion of our Appalachian Basin operations. Although an agreement signed in the third quarter of 2014 for the sale of our coalbed methane assets in Wyoming was terminated, we continue our efforts to complete a sale of these assets in the foreseeable future. Subsequent to June 30, 2015, we signed an agreement for the sale of our coalbed methane assets in the Powder River Basin (see Note 11 of Notes to Consolidated Financial Statements for further discussion of the agreement). Additionally, we are evaluating other transactions that would monetize certain of our assets and enable us to redeploy the sales proceeds in areas where there is an opportunity for a higher return or reduce debt levels. As stated in the past, the market conditions may be challenging for producers but may give rise to opportunities for acquisitions in areas that would be a complimentary addition to our portfolio. Such an opportunity arose for us and subsequent to June 30, 2015, we signed a definitive merger agreement to acquire privately held RKI Exploration & Production, LLC ("RKI") for $2.75 billion, consisting of 40 million unregistered shares of WPX common stock and approximately $2.28 billion in cash (the “Acquisition”). RKI and the related financing transactions subsequent to June 30, 2015 are discussed further in Note 11 of Notes to Consolidated Financial Statements.

We believe the Acquisition accomplishes several strategic objectives for us and is complementary to our business strategies in the following ways:

- Build Asset Scale. The Acquisition provides an entry into the Delaware Basin, a significant resource play with multiple horizons of oil in place. The asset scale and concentrated acreage position will allow for efficient, low-cost development activities over a number of years.
- Increase Margins. The Delaware Basin assets associated with the Acquisition contain both current oil production and undeveloped resource potential, allowing for an increase in near term cash margins, along with the potential for oil reserve and production growth in the future.
- Continue Oil Development. The entry into a new, oil-focused basin and the incremental drilling returns associated with the Acquisition will provide additional optionality to our portfolio, providing for a more balanced commodity mix and the opportunity to allocate capital in an additional basin where expected returns are attractive to WPX's current assets.
- Operational Excellence. Our management team's history of operating large-scale resource development plays will be complemented by the addition of a proven, established operational team from RKI and the associated midstream assets that provide the necessary infrastructure to increase development operations.

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 significant protection to price downturns in 2015. Our 2015 drilling activity has been greatly reduced in comparison to 2014 as we continue to either drill locations that generate the highest economic returns, preserve leases or optimize the drilling rigs already under contract in an effort to reduce the impact of rig release penalties. 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 working with our vendors to lower costs on goods and services. We continue to make progress in all of these areas. We continue to review our general and administrative costs and services. In March 2015, we announced that we would trim our company-wide workforce by approximately 8 percent and consolidate most of our regional office staff in Denver, Colorado, with personnel at the Company's headquarters in Tulsa, Oklahoma.

Our 2015 capital program is expected to be in line with our projected cash flow. Through June 30, 2015, our 2015 capital activity totaled $435 million, including $138 million in the second quarter, while cash flow from operations was $430 million.

Planned capital investments for new activity in full-year 2015 are approximately $725 million to $805 million and excludes any capital investments activity of RKI after the closing of the Acquisition. A slower run rate for the latter half of the year is expected to offset a stronger run rate in the first two quarters. Including capital investments of RKI after closing of the Acquisition, we estimate capital investments of $825 million to $925 million.

For the full-year 2015, we expect to spend $285 million to $305 million in the Williston Basin optimizing rigs already under contract at the beginning of the year and have ramped down to one rig by late spring but plan to potentially add two rigs in the second half of 2015, with one beginning in August and the second in November. Additionally, we plan to resume completions of previously drilled wells for which we were deferring completions. We expect to spend $290 million to $310 million in the Gallup Sandstone in 2015, primarily preserving the leases and forming units. Despite the decrease in the capital expenditures in 2015, we are targeting a 20 to 25 percent full-year growth in oil production.

We will be reducing our natural gas drilling effort in the Piceance Basin because of lower expected natural gas pricing in the near term. The Piceance Basin offers scale and efficiency combined with significant infrastructure already in place. We expect to spend $150 million to $165 million in the Piceance Basin and plan to move to a one rig program during the second half of 2015. A portion of the Piceance Basin activity includes limited drilling in the Niobrara Shale that is focused on resource evaluation, driving down costs and optimizing completion techniques. To date, our drilling activity has primarily been focused in the Piceance Valley, but we plan 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.

As we execute on our long-term strategy, 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 diversify our commodity portfolio (production and reserves) through the development of our oil play positions in the Williston Basin and Gallup Sandstone in the San Juan Basin;
- continuing to pursue cost improvements and efficiency gains;
- employing new technology and operating methods;
- continuing to invest in projects to assess resources and add new development opportunities to our portfolio;
- retaining the flexibility to make adjustments to our planned levels and allocation of capital 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 in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2014. 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 use master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. For the remainder of 2015 and 2016, we have the following contracts as of the date of this filing shown at weighted average volumes and basin-level weighted average prices:

Natural Gas	Jul - Dec 2015		2016	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed-price—Henry Hub	410	$4.05	280	$3.81
Swaptions—Henry Hub	—	$—	90	$4.23
Collars—Henry Hub	50	$ 4.00 - 4.50	—	$—
Basis swaps—NGPL	20	$(0.18)	—	$—
Basis swaps—San Juan	108	$(0.11)	—	$—
Basis swaps—Rockies	280	$(0.17)	—	$—
Basis swaps—SoCal	50	$0.08	—	$—

Crude Oil	Jul - Dec 2015		2016	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed-price—WTI	18,500	$94.75	15,500	$61.86
Swaptions—WTI	—	$—	8,500	$84.27
Basis swaps—Midland	2,500	$0.30	5,000	$(0.45)

In conjunction with the closing of a sale of our Powder River Basin assets, 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 thereafter total $155 million.

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, which include the management of various commodity contracts, such as transportation and related derivatives, coupled with the sale of our commodity volumes.

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Natural gas sales	$127	$262	$(135)	(52)%
Oil and condensate sales	145	194	(49)	(25)%
Natural gas liquid sales	25	54	(29)	(54)%
Total product revenues	297	510	(213)	(42)%
Gas management	57	231	(174)	(75)%
Net gain (loss) on derivatives	(71)	(17)	(54)	NM
Other	1	3	(2)	(67)%
Total revenues	$284	$727	$(443)	(61)%

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

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

- $135 million decrease in natural gas sales reflects $97 million related to lower sales prices and a $38 million decrease related to lower production sales volumes. The decrease in our production sales volumes is due in part to the impact of the sales of Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014 (see Note 4 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 76 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for the three months ended June 30, 2015 and 2014:

	Three months ended June 30, 2015	2014
Natural gas sales (per Mcf)	$2.08	$3.66
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	1.02	(0.13)
Natural gas net price including derivative settlements (per Mcf)	$3.10	$3.53
Natural gas production sales volumes (MMcf)	61,388	71,972
Per day natural gas production sales volumes (MMcf/d)	675	791

(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $49 million decrease in oil and condensate sales reflects $121 million related to lower sales prices for the three months ended June 30, 2015 as compared to 2014, partially offset by a $72 million increase related to higher production sales volumes. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin and the Gallup Sandstone in the San Juan Basin. In the Williston and San Juan Basins, volumes were 22.6 MBbls per day and 8.5 MBbls per day, respectively, for the three months ended June 30, 2015 compared to 18.8 MBbls per day and 3.0 MBbls per day, respectively, for the same period in 2014. The following table reflects oil and condensate production prices and volumes for the three months ended June 30, 2015 and 2014:

	Three months ended June 30, 2015	2014
Oil sales (per barrel)	$48.60	$89.24
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	24.92	(3.40)
Oil net price including derivative settlements (per barrel)	$73.52	$85.84
Oil and condensate production sales volumes (MBbls)	2,975	2,159
Per day oil and condensate production sales volumes (MBbls/d)	32.7	23.7

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $29 million decrease in natural gas liquids sales primarily reflects lower NGL prices for 2015 compared to 2014. The following table reflects NGL production prices and volumes for the three months ended June 30, 2015 and 2014:

	Three months ended June 30, 2015	2014
NGL sales (per barrel)	$13.76	$33.58
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	(0.30)
NGL net price including derivative settlements (per barrel)	$13.76	$33.28
NGL production sales volumes (MBbls)	1,791	1,625
Per day NGL production sales volumes (MBbls/d)	19.7	17.9

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

The following table summarizes the composition of the Piceance NGL barrel for the three months ended June 30, 2015 and 2014:

	Three months ended June 30, 2015 % of barrel	$/gallon	2014 % of barrel	$/gallon
Ethane	36 %	$0.20	33 %	$0.29
Propane	30 %	$0.46	31 %	$1.06
Iso-Butane	8 %	$0.60	9 %	$1.30
Normal Butane	8 %	$0.59	8 %	$1.25
Natural Gasoline	18 %	$1.23	19 %	$2.21

- $174 million decrease in gas management revenues primarily due to lower average prices on physical natural gas sales as well as lower commodity sales volumes. The decrease in volumes primarily relates to the sale of a package of marketing contracts in the second quarter of 2015 and the release of certain firm transportation capacity in the first and second quarters of 2015 (see Note 4 of Notes to Consolidated Financial Statements). Most of the net gas management margin recognized in the winter months was a result of activity around these contracts and firm transportation capacity. As a result, gas management revenues, expenses and net margins in future periods will be significantly less than current levels. We experienced a similar decrease of $174 million in related gas management costs and expenses, discussed below.

- $54 million unfavorable change in net gain (loss) on derivatives primarily reflects a $198 million unfavorable change in unrealized gains (losses) on derivatives related to production, primarily natural gas and crude, partially offset by a $153 million favorable change realized on derivatives for our production.

Cost and operating expense and operating income (loss) analysis

	Three months ended June 30, 2015 (Millions)	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Costs and expenses:				
Lease and facility operating	$51	$59	$8	14 %
Gathering, processing and transportation	69	78	9	12 %
Taxes other than income	19	33	14	42 %
Gas management, including charges for unutilized pipeline capacity	59	233	174	75 %
Exploration	6	54	48	89 %
Depreciation, depletion and amortization	227	202	(25)	(12)%
Net (gain) loss on sales of assets	(209)	—	209	NM
Loss on sale of working interests in the Piceance Basin	—	195	195	100 %
General and administrative	63	70	7	10 %
Other—net	5	1	(4)	NM
Total costs and expenses	$290	$925	$635	69 %
Operating income (loss)	$(6)	$(198)	$192	97 %

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

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

- $8 million decrease in lease and facility operating expenses primarily relates to lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014 as well as cost reduction efforts in the Piceance Basin. This decrease is partially offset by higher oil production volumes for the three months ended June 30, 2015. Lease and facility operating expense averaged $3.39 per Boe for the three months ended June 30, 2015 compared to $3.75 per Boe for the same period in 2014.
- $9 million decrease in gathering, processing and transportation expenses primarily related to lower natural gas volumes. Additionally, during the three months ended June 30, 2014, we recognized approximately $5 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company. Gathering, processing and transportation expenses averaged $4.61 per Boe for the three months ended June 30, 2015 and $4.99 per Boe for the same period in 2014.
- $14 million decrease in taxes other than income from 2015 compared to 2014 primarily relates to lower commodity prices and decreased natural gas production volumes, partially offset by higher oil production volumes. Taxes other than income averaged $1.23 per Boe for the three months ended June 30, 2015 compared to $2.11 per Boe for the same period in 2014.
- $174 million decrease in gas management expenses primarily due to lower average prices on physical natural gas cost of sales as well as lower commodity purchase volumes, as previously discussed. Additionally, during the three months ended June 30, 2014, we recognized approximately $11 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company. Also included in gas management expenses are $9 million and $12 million for the three months ended June 30, 2015 and 2014, respectively, for unutilized pipeline capacity.

- $48 million decrease in exploration expenses primarily relates to impairments in 2014 of exploratory area leasehold and well costs in exploratory plays for which management no longer intends to continue exploratory activities (see Note 4 of Notes to Consolidated Financial Statements).

- $25 million increase in depreciation, depletion and amortization partially due to higher oil production volumes. Also, during the three months ended June 30, 2015, we adjusted the proved reserves used for the calculation of depletion and amortization to reflect the impact of a decrease in the 12-month average price resulting in approximately $7 million of additional depreciation, depletion and amortization coupled with the $5 million impact from first quarter. Further decreases in the 12-month average price may result in additional increases in our depreciation, depletion and amortization expense. During the three months ended June 30, 2015, our depreciation, depletion and amortization averaged $15.14 per Boe compared to an average $12.79 per Boe for the same period in 2014.
- $209 million gain on sales of assets primarily relates to the sale of a package of marketing contracts and release of certain related firm transportation capacity (see Note 4 of Notes to Consolidated Financial Statements).
- $195 million favorable change due to the loss on the sale of a portion of our working interests in certain Piceance Basin wells in 2014 (see Note 4 of Notes to Consolidated Financial Statements).
- $7 million decrease in general and administrative expenses primarily due to reduced employee and related costs as a result of headcount reductions partially offset by approximately $7 million of severance and relocation costs associated with the workforce reduction and office consolidation announced during the first quarter of 2015. General and administrative expenses averaged $4.21 per Boe for the three months ended June 30, 2015 compared to $4.40 per Boe for the same period in 2014. Excluding the severance and relocation costs, the average expense for the three months ended June 30, 2015 would have been $3.75 per Boe.

Results below operating income (loss)

	Three months ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$(6)	$(198)	$192	97%
Interest expense	(32)	(28)	(4)	(14)%
Investment income and other	1	—	1	NM
Income (loss) from continuing operations before income taxes	(37)	(226)	189	84%
Provision (benefit) for income taxes	(14)	(82)	(68)	(83)%
Income (loss) from continuing operations	(23)	(144)	121	84%
Income (loss) from discontinued operations	(7)	11	(18)	NM
Net income (loss)	(30)	(133)	103	77%
Less: Net income (loss) attributable to noncontrolling interests	—	2	(2)	(100)%
Net income (loss) attributable to WPX Energy, Inc.	$(30)	$(135)	$105	78%

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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 the notes issued in the third quarter of 2014.

Provision (benefit) for income taxes changed unfavorably due to a favorable change in pre-tax loss 2015 compared to 2014. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

The change in income (loss) from discontinued operations was primarily due to the completion of the sale of Apco in first-quarter 2015 and a $6 million impairment in the Powder River Basin for the three months ended June 30, 2015 (see Note 2 of Notes to Consolidated Financial Statements).

Six Month-Over-Six Month Results of Operations
Revenue Analysis

	Six months ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Natural gas sales	$294	$579	$(285)	(49)%
Oil and condensate sales	262	343	(81)	(24)%
Natural gas liquid sales	48	115	(67)	(58)%
Total product revenues	604	1,037	(433)	(42)%
Gas management	215	792	(577)	(73)%
Net gain (loss) on derivatives	34	(212)	246	NM
Other	3	4	(1)	(25)%
Total revenues	$856	$1,621	$(765)	(47)%

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

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

- $285 million decrease in natural gas sales is primarily due to $210 million related to lower sales prices and $75 million related to lower production sales volumes. The decrease in our production sales volumes is due in part to the impact of the sales of Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014. Natural gas production from the Piceance Basin represented approximately 75 percent of our total natural gas production. The following table reflects natural gas production prices and volumes for the six months ended June 30, 2015 and 2014:

	Six months ended June 30, 2015	2014
Natural gas sales (per Mcf)	$2.35	$4.04
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	1.04	(0.38)
Natural gas net price including derivative settlements (per Mcf)	$3.39	$3.66
Natural gas production sales volumes (MMcf)	124,865	143,503
Per day natural gas production sales volumes (MMcf/d)	690	793

(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $81 million decrease in oil and condensate sales reflects $274 million related to lower sales prices partially offset by a $193 million increase related to higher production sales volumes for 2015 compared to 2014. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin and the Gallup Sandstone in the San Juan Basin. In the Williston and San Juan Basins, volumes were 23.7 MBbls per day and 8.3 MBbls per day, respectively, for the first six months of 2015 compared to 17.2 MBbls per day and 2.4 MBbls per day, respectively, for the same period in 2014. The following table reflects oil and condensate production prices and volumes for the six months ended June 30, 2015 and 2014:

	Six months ended June 30, 2015	2014
Oil sales (per barrel)	$ 42.99	$ 87.90
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	27.26	(2.91)
Oil net price including derivative settlements (per barrel)	$ 70.25	$ 84.99
Oil and condensate production sales volumes (MBbls)	6,092	3,896
Per day oil and condensate production sales volumes (MBbls/d)	33.7	21.5

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $67 million decrease in natural gas liquids sales primarily reflects lower NGL prices for 2015 compared to 2014. The following table reflects NGL production prices and volumes for the six months ended June 30, 2015 and 2014:

	Six months ended June 30, 2015	2014
NGL sales (per barrel)	$ 14.51	$ 35.90
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	(0.39)
NGL net price including derivative settlements (per barrel)	$ 14.51	$ 35.51
NGL production sales volumes (MBbls)	3,310	3,212
Per day NGL production sales volumes (MBbls/d)	18.3	17.7

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

The following table summarizes the composition of the Piceance NGL barrel for the six months ended June 30, 2015 and 2014:

	Six months ended June 30, 2015 % of barrel		$/gallon	2014 % of barrel		$/gallon
Ethane	31	%	$ 0.21	32	%	$ 0.29
Propane	33	%	$ 0.51	32	%	$ 1.17
Iso-Butane	9	%	$ 0.65	9	%	$ 1.35
Normal Butane	8	%	$ 0.65	8	%	$ 1.31
Natural Gasoline	19	%	$ 1.16	19	%	$ 2.16

- $577 million decrease in gas management revenues is primarily due to lower average prices on physical natural gas sales as well as lower commodity sales volumes. The decrease in volumes primarily relates to the sale of a package of marketing contracts in the second quarter of 2015 and release of certain related firm transportation capacity in the first and second quarters of 2015 (see Note 4 of Notes to Consolidated Financial Statements). The decrease in the sales price was greater than the decrease in the purchase price as reflected in the $456 million decrease in related gas management costs and expenses, discussed below.

- $246 million favorable change in net gain (loss) on derivatives primarily reflects a $164 million favorable change on derivatives related to our production, primarily natural gas and crude, and a $82 million favorable change on derivatives related to gas management.

Cost and operating expense and operating income (loss) analysis

	Six months ended June 30, 2015 (Millions)	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Costs and expenses:				
Lease and facility operating	$108	$119	$11	9 %
Gathering, processing and transportation	142	167	25	15 %
Taxes other than income	41	68	27	40 %
Gas management, including charges for unutilized pipeline capacity	168	624	456	73 %
Exploration	13	69	56	81 %
Depreciation, depletion and amortization	443	395	(48)	(12)%
Net (gain) loss on sales of assets	(278)	—	278	NM
Loss on sale of working interests in the Piceance Basin	—	195	195	100 %
General and administrative	127	137	10	7 %
Other—net	31	3	(28)	NM
Total costs and expenses	$795	$1,777	$982	55 %
Operating income (loss)	$61	$(156)	$217	NM

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

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

- $11 million decrease in lease and facility operating expenses primarily relates to lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014 as well as cost reduction efforts in the Piceance Basin. This decrease is partially offset by higher oil production volumes for the six months ended June 30, 2015 compared to the same period in 2014. Lease and facility operating expense averaged $3.56 per Boe for the six months ended June 30, 2015 compared to $3.87 per Boe for the same period in 2014.
- $25 million decrease in gathering, processing and transportation expenses primarily relates to lower natural gas volumes. Additionally, during the six months ended June 30, 2014, we recognized approximately $5 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company. Gathering, processing and transportation charges averaged $4.71 per Boe for 2015 and $5.39 per Boe for 2014.
- $27 million decrease in taxes other than income primarily relates to lower commodity prices and decreased natural gas production volumes, partially offset by higher oil production volumes. Taxes other than income averaged $1.34 per Boe for the six months ended June 30, 2015 compared to $2.19 per Boe for the same period in 2014.
- $456 million decrease in gas management expenses is primarily due to lower average prices on physical natural gas cost of sales as well as lower commodity purchase volumes, as previously discussed. Additionally in 2014, we recognized approximately $11 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company. Also included in gas management expenses are $19 million and $28 million for the six months ended June 30, 2015 and 2014, respectively, for unutilized pipeline capacity.
- $56 million decrease in exploration expenses primarily relates to impairments in 2014 of exploratory area leasehold and well costs in exploratory plays for which management no longer intends to continue exploratory activities (see Note 4 of Notes to Consolidated Financial Statements).
- $48 million increase in depreciation, depletion and amortization is primarily due to higher oil production volumes. Also, during 2015, we have adjusted the proved reserves used for the calculation of depletion and amortization to

reflect the impact of a decrease in the 12-month average price resulting in a $17 million addition to depreciation, depletion and amortization. Further decreases in the 12-month average price may result in additional increases in our depreciation, depletion and amortization expense. During the six months ended June 30, 2015, our depreciation, depletion and amortization averaged $14.67 per Boe compared to an average $12.73 per Boe for the same period in 2014.

- $278 million net gain on sales of assets primarily relates to the sales of a package of marketing contracts and release of certain related firm transportation capacity in the second quarter of 2015 and a portion of our Appalachian Basin assets in the first quarter of 2015 (see Note 4 of Notes to Consolidated Financial Statements).
- $195 million favorable change due to the loss on the sale of a portion of our working interests in certain Piceance Basin wells in 2014 (see Note 4 of Notes to Consolidated Financial Statements).
- $10 million decrease in general and administrative expenses is primarily due to reduced employee and related costs as a result of headcount reductions partially offset by approximately $15 million of severance and relocation costs associated with the workforce reduction and office consolidation announced during the first quarter of 2015. General and administrative expenses averaged $4.21 per Boe for the six months ended June 30, 2015 compared to $4.41 per Boe for the same period in 2014. Excluding the severance and relocation costs, general and administrative expenses would have averaged $3.71 per Boe for 2015.
- $28 million increase in other expenses primarily relates to expenses recorded in association with a contract termination in the first quarter of 2015 (see Note 4 of Notes to Consolidated Financial Statements).

Results below operating income (loss)

	Six months ended June 30, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$61	$(156)	$217	NM
Interest expense	(65)	(57)	(8)	(14)%
Investment income and other	2	—	2	NM
Income (loss) from continuing operations before income taxes	(2)	(213)	211	99%
Provision (benefit) for income taxes	(1)	(69)	(68)	(99)%
Income (loss) from continuing operations	(1)	(144)	143	99%
Income (loss) from discontinued operations	39	30	9	30%
Net income (loss)	38	(114)	152	NM
Less: Net income (loss) attributable to noncontrolling interests	1	3	(2)	(67)%
Net income (loss) attributable to WPX Energy, Inc.	$37	$(117)	$154	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 the notes issued in the third quarter of 2014.

Provision (benefit) for income taxes in 2015 changed unfavorably compared to 2014 primarily due to a favorable change in pre-tax loss for the six months ended June 30, 2015 compared to a pre-tax loss for 2014. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods. The provision for income taxes in 2014 reflects an additional $9 million of deferred tax expense to accrue for the impact of new legislation enacted by the state of New York on March 31, 2014 (see Note 7 of Notes to Consolidated Financial Statements).

The change in income (loss) from discontinued operations was primarily due to the gain on the sale of Apco partially offset by a $16 million impairment in the Powder River Basin for the six months ended June 30, 2015 (see Note 2 of Notes to Consolidated Financial Statements).

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

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 June 30, 2015, we maintained liquidity through cash, cash equivalents and available credit capacity under our credit facility; and
- 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, the acquisition of RKI 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 the debt and equity offerings noted below, proceeds from monetization of assets and, if necessary, borrowings on our $1.5 billion credit facility. We anticipate that the combination of these sources should 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, excluding RKI, are estimated to be approximately $875 million to $955 million in 2015 and exceed the previously mentioned $725 million to $805 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;
- acquisition of RKI during the third quarter of 2015 and related financing transactions (see Note 11 of Notes to Consolidated Financial Statements);
- targeting to de-lever through $400 million to $500 million in asset divestitures by the end of 2015 (with similar levels targeted in 2016); 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 leasehold; and
- reduced access to our credit facility.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses throughout 2015. Our internal and external sources of consolidated liquidity include cash generated from operations, cash and cash equivalents on hand, and our credit facility. Additional sources of liquidity, if needed and if available, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales.

Equity Offerings

On July 22, 2015, we completed equity offerings of (a) 30,000,000 shares of our common stock (or 34,500,000 shares if the underwriters exercise their option to purchase additional shares in full) for gross proceeds of approximately $303 million (or approximately $348 million if the underwriters exercise their option to purchase additional shares in full) at the public offering price of $10.10 per share and (b) $350 million of aggregate liquidation preference of 6.25% series A mandatory convertible preferred stock (or $402.5 million of aggregate liquidation preference if the underwriters exercise their option to purchase additional shares in full).

Senior Notes

On July 22, 2015, we completed an offering of (i) $500 million aggregate principal amount of the Company's 7.50% Senior Notes due 2020 (the "2020 Notes") and (ii)$500 million aggregate principal amount of the Company's 8.25% Senior

Notes due 2023 (the “2023 Notes” and together with the 2020 Notes, the “Notes”). The Notes were issued under an Indenture, dated as of September 8, 2014 (the “Base Indenture”), as supplemented by the Second Supplemental Indenture, dated as of July 22, 2015 (the “Second Supplemental Indenture”), each between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee (as so supplemented, the “Indenture”).

The Notes are the Company’s senior unsecured obligations ranking equally with the Company’s other existing and future senior unsecured indebtedness. The 2020 Notes bear interest at a rate of 7.50% per annum, and the 2023 Notes bear interest at a rate of 8.25% per annum. Interest is payable on the Notes semiannually in arrears on February 1 and August 1 of each year commencing on February 1, 2016. The 2020 Notes will mature on August 1, 2020. The 2023 Notes will mature on August 1, 2023. At any time or from time to time prior to July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, the Company may, at its option, redeem the applicable series of Notes, in whole or in part, at a make-whole redemption price as set forth in the Indenture. The Company also has the option, at any time or from time to time on or after July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, to redeem some or all of the applicable series of Notes at a redemption price equal to 100% of the principal amount of the Notes to be redeemed, as more fully described in the Indenture. The Notes are also subject to a special mandatory redemption, as more fully described in the Indenture, if the Company’s previously announced Acquisition is not consummated by, or the merger agreement related to such acquisition is terminated prior to November 30, 2015.

The Indenture contains covenants that, among other things, restrict the Company's ability to grant liens on its assets and merge, consolidate or transfer or lease all or substantially all of its assets, subject to certain qualifications and exceptions.

Credit Facility

As of June 30, 2015, we had a $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 lenders party thereto (the “Credit Facility”). Under the terms of the Credit Facility 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 matures on October 28, 2019. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of June 30, 2015, we were in compliance with our financial covenants, had full access to the Credit Facility and did not have any outstanding borrowings. For additional information regarding the terms of our Credit Facility, see our Annual Report on Form 10-K for the year ended December 31, 2014.
Under the Credit Facility when our long-term unsecured debt rating was 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 were required to maintain a ratio of Consolidated Net Indebtedness (as defined in the Credit Facility) to Consolidated EBITDAX (as defined in the Credit Facility) 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 is 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) is not permitted to be greater than 60 percent and is applicable for the life of the agreement. If our long-term unsecured debt rating was 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 were also 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, to Consolidated Indebtedness 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 were 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.

Amendments to Credit Facility and commitment increase

On July 16, 2015, the Company amended its Credit Facility to, among other things (a) modify the financial covenants in a manner favorable to the Company in respect of (i) the ratio of PV to Consolidated Indebtedness and (ii) the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX and (b) add a financial covenant requiring a minimum ratio of Consolidated EBITDAX to Consolidated Interest Charges (each capitalized term used herein but not defined is
defined in the Company's Credit Facility, as amended).

Under the amended Credit Facility, if the Company's Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody's or (b) B+ or worse by S&P or B1 or worse by Moody's, we will 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, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company's Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody's (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody's.

In addition, the amendment increased the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX we are required to maintain to not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company's Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody's and not less than BB+ or Ba1 by the other such agency. Furthermore, the amendment added a financial covenant requiring us to not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.50 to 1.00.

Under the terms of the Credit Facility 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. On July 31, 2015, the commitments from existing lenders were increased by $250 million, for total commitments of $1.75 billion. For additional information regarding activity on the Credit Facility subsequent to June 30, 2015, see Note 11 of Notes to Consolidated Financial Statements.

We have three bilateral, uncommitted letter of credit agreements which we anticipate will be renewed annually. These agreements allow us to preserve our liquidity under our Credit Facility 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. At June 30, 2015, a total of $233 million in letters of credit have been issued.

Sources (Uses) of Cash

	Six months ended June 30, 2015	2014
	(Millions)	
Net cash provided (used) by:		
Operating activities	$430	$520
Investing activities	95	(395)
Financing activities	(278)	(114)
Increase (decrease) in cash and cash equivalents	$247	$11

Operating activities

Our net cash provided by operating activities for the six months ended June 30, 2015 decreased from the same period in 2014 primarily due to a decrease in total cash provided by operating activities related to discontinued operations. Total cash provided by operating activities related to discontinued operations was approximately $9 million and $67 million for the six months ended June 30, 2015 and 2014, respectively. In addition, total cash provided by operating activities related to continuing operations decreased due to a decrease in commodity prices and natural gas volumes, substantially offset by cash received on settlement of derivative contracts and higher oil volumes.

Investing activities

Cash capital expenditures for drilling and completion were $579 million and $604 million for the six months ended June 30, 2015 and 2014, respectively. Capital expenditures incurred during the six months ended June 30, 2015 and 2014 for drilling and completions were $365 million and $628 million, respectively. Domestic land activities were $35 million and $57 million during the six months ended June 30, 2015 and 2014, respectively. In addition, expenditures related to international were $15 million and $36 million for the six months ended June 30, 2015 and 2014, respectively.

Significant components related to proceeds from the sale of our international interests and domestic assets are comprised of the following:

2015

•$209 million for the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast during May 2015 (see Note 4 of Notes to Consolidated Financial Statements).

•$288 million for the sale of a portion of our Appalachian Basin operations and release of certain firm transportation capacity to Southwestern Energy Company during the first quarter of 2015 (see Note 4 of Notes to Consolidated Financial Statements).

•$291 million after expenses but before $17 million of cash on hand at Apco as of the closing date, for the divestiture of our 69 percent controlling equity interest in Apco and additional Argentina-related assets to Pluspetrol (see Note 2 of Notes to Consolidated Financial Statements).

2014

•We received approximately $329 million for the sale of a portion of our working interests in certain Piceance Basin wells to Legacy during the second quarter of 2014 (see Note 4 of Notes to Consolidated Financial Statements).

Financing activities

Net cash used by financing activities for the six months ended June 30, 2015 was primarily due to the repayment of all outstanding amounts on borrowings under the Credit Facility as previously discussed. Net cash used by financing activities in 2014 primarily relates to repayments of our revolving Credit Facility (see Note 6 of Notes to Consolidated Financial Statements) in excess of amounts borrowed to partially fund capital expenditures in the first half of 2014.

Contractual Obligations

In conjunction with certain assets sales during the first half of 2015, our contractual obligations were reduced by the following:

- Approximately $390 million in future demand payment obligations for transportation commitments (see Note 4 of Notes to Consolidated Financial Statements); and
- Approximately $1.6 billion in liabilities associated with physical and financial derivatives in which the purchase obligation was assigned to a third party.

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 June 30, 2015 or at December 31, 2014.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first six months of 2015.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, oil and natural gas liquids 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 9 and 10 of Notes to Consolidated Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any

potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

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

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net liability of less than $1 million at June 30, 2015 and a net asset of less than $1 million at December 31, 2014, respectively. The value at risk for contracts held for trading purposes was less than $1 million at June 30, 2015 and December 31, 2014.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas and crude oil purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $261 million and $493 million at June 30, 2015 and December 31, 2014, respectively. The value at risk for derivative contracts held for nontrading purposes was $19 million at June 30, 2015 and $16 million at December 31, 2014. During the last 12 months, our value at risk for these contracts ranged from a high of $19 million to a low of $16 million.

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (“Disclosure Controls”) or our internal control over financial reporting (“Internal Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people or by management override of the control. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There have been no changes during the second quarter of 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings
The information called for by this item is provided in Note 8 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.
Item 1A. Risk Factors
Risk Factors Relating to the Acquisition
If the Acquisition is consummated, we may be unable to successfully integrate RKI's operations or to realize targeted cost savings, revenues or other benefits of the Acquisition.
We entered into the Merger Agreement because we believe that the Acquisition will be beneficial to us. Achieving the targeted benefits of the Acquisition will depend in part upon whether we can integrate RKI's businesses in an efficient and effective manner. We may not be able to accomplish this integration process smoothly or successfully. The successful acquisition of producing properties, including those acquired from RKI, requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas and oil prices and their appropriate differentials;
- availability and cost of transportation of production to markets;
- availability and cost of drilling equipment and of skilled personnel;
- development and operating costs and potential environmental and other liabilities;
- regulatory, permitting and similar matters; and
- our ability to obtain external financing to fund the purchase price.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we have performed a review of the subject properties that we believe to be generally consistent with industry practices. Our review may not reveal all existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections will not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. As is the case with the Acquisition, we are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis, and, as is the case with certain liabilities associated with the assets to be acquired, we are entitled to indemnification for only certain environmental liabilities. The integration process may be subject to delays or changed circumstances, and we can give no assurance that the acquired properties will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of the Acquisition will materialize.
Significant acquisitions, including the Acquisition, and other strategic transactions may involve other risks that may cause our business to suffer, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate assets;
- the challenge of attracting and retaining personnel associated with acquired operations; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

We will incur significant transaction and acquisition-related costs in connection with the Acquisition.
We expect to incur significant costs associated with the Acquisition and combining the operations of the two companies, including costs to achieve targeted cost-savings. The substantial majority of the expenses resulting from the Acquisition will be composed of transaction costs related to the Acquisition, systems consolidation costs, and business integration and employment-related costs, including costs for severance, retention and other restructuring. We may also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs

may be incurred in the

integration of the two companies' businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset incremental transaction and acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

The Acquisition may not be successful.

We recently announced our entry into the Merger Agreement to acquire RKI. Risks associated with the Acquisition include the risk that the transaction may not be consummated, the risk that regulatory approval that may be required for the transaction is not obtained or is obtained subject to certain conditions that are not anticipated, litigation risk associated with claims or potential claims brought by equity holders of RKI to enjoin the transaction or seek monetary damages and risks associated with our ability to issue debt and equity to fund the purchase price.

In addition, Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2014, includes certain risk factors that could materially affect our business, financial condition or future results. Those risk factors have not materially changed as of June 30, 2015.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

EXHIBITS

Exhibit No.	Description
2.1	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
2.2**	Agreement and Plan of Merger, dated October 2, 2014, by and among Pluspetrol Resources Corporation, Pluspetrol Black River Corporation and Apco Oil and Gas International Inc. (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on October 7, 2014)
2.3**	Agreement and Plan of Merger, dated as of July 13, 2015, by and among RKI Exploration & Production, LLC, WPX Energy, Inc. and Thunder Merger Sub LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on January 6, 2012)
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
3.3	Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on March 21, 2014)
3.4	Certificate of Designations for 6.25% Series A Mandatory Convertible Preferred Stock (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on July 22, 2015)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
4.2	Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.3	First Supplemental Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.4	Second Supplemental Indenture, dated as of July 22, 2015, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
10.1	

	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on January 6, 2012)
10.4	Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on January 6, 2012)
10.5	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)

Exhibit No.	Description
10.6#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.’s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
10.7	Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current report on Form 8-K filed with the SEC on July 23, 2012) (1)
10.8	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.’s current report on Form 8-K filed with the SEC on July 23, 2012) (1)
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.’s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on May 29, 2013) (1)
10.11	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.’s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) (1)
10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13	Form of Restricted Stock Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.14	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.15	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2015) (1)
10.16	Form of Stock Option Agreement between WPX Energy, Inc. and Section 16 Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.17	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)

10.18	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.19	Agreement, dated December 17, 2013, between WPX Energy, Inc. and Taconic Capital Advisors L.P. (incorporated herein by reference to Exhibit 99.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 18, 2013)
10.20	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 17, 2013)
10.21	Severance Agreement, dated February 18, 2014, between WPX Energy, Inc. and Neal A. Buck (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 19, 2014) (1)

Exhibit No.	Description
10.22	Employment Agreement, dated April 29, 2014, between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.23	Form of Nonqualified Stock Option Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.24	Form of 2014 Time-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.25	Form of 2014 Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.26	Form of Time-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.5 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.27	Form of Performance-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.6 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.28	Form of Restricted Stock Unit Award between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.29	Separation and Release Agreement, dated July 28, 2014, between WPX Energy, Inc. and James J. Bender (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.30	WPX Energy Executive Severance Pay Plan (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 19, 2014) (1)
10.31	Amended and Restated Credit Agreement, dated as of October 28, 2014, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on November 3, 2014)
10.32	Form of Voting and Support Agreement, dated as of July 13, 2015, by and between WPX Energy, Inc. and the Member signatory thereto (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
10.33	First Amendment to the Amended and Restated Credit Agreement, dated as of July 16, 2015, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as existing administrative agent and existing swingline lender, and Wells Fargo Bank, National Association, as successor administrative agent and successor swingline lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy,

	Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
12*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

#	Certain portions have been omitted pursuant to an Order Granting Confidential Treatment issued by the SEC on December 5, 2011. Omitted information has been filed separately with the SEC.
*	Filed herewith
**	All schedules to the Merger Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished to the SEC upon request
(1)	Management contract or compensatory plan or arrangement

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WPX Energy, Inc.
(Registrant)

By: /s/ Stephen L. Faulkner
Stephen L. Faulkner
Controller
(Principal Accounting Officer)

Date: August 6, 2015