

WPX ENERGY, INC.
Form 10-Q
August 01, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q
(Mark One)

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

For the quarterly period ended June 30, 2013

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

For the transition period from to
Commission file number 1-35322

WPX Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware 45-1836028
(State or Other Jurisdiction of (IRS Employer
Incorporation or Organization) Identification No.)

One Williams Center, 74172-0172
Tulsa, Oklahoma (Zip Code)
(Address of Principal Executive Offices)

855-979-2012
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:
Title of Each Class Name of Each Exchange on Which Registered
Common Stock, \$0.01 par value New York Stock Exchange

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

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

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 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 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

The number of shares outstanding of the registrant's common stock at July 31, 2013 were 200,587,742.

WPX Energy, Inc.
Index

	Page
Part I.	
Financial Information	
Item 1.	
Financial Statements	
<u>Consolidated Balance Sheets as of June 30, 2013 and December 31, 2012</u>	4
<u>Consolidated Statements of Operations for the three and six months ended June 30, 2013 and 2012</u>	5
<u>Consolidated Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2013 and 2012</u>	6
<u>Consolidated Statements of Changes in Equity for the six months ended June 30, 2013</u>	7
<u>Consolidated Statements of Cash Flows for the six months ended June 30, 2013 and 2012</u>	8
<u>Notes to Consolidated Financial Statements</u>	9
Item 2.	
<u>Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	24
Item 3.	
<u>Quantitative and Qualitative Disclosures About Market Risk</u>	34
Item 4.	
<u>Controls and Procedures</u>	35
Part II.	
<u>Other Information</u>	35
Item 1.	
<u>Legal Proceedings</u>	35
Item 1A.	
<u>Risk Factors</u>	35
Item 2.	
Unregistered Sales of Equity Securities and Use of Proceeds	35
Item 3.	
Defaults Upon Senior Securities	35
Item 4.	
Mine Safety Disclosures	35
Item 5.	
Other Information	35
Item 6.	
<u>Exhibits</u>	36

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
Natural gas, crude oil, and natural gas liquids (“NGL”) prices and demand.

2

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

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Acts of terrorism; and
- 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 I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012.

WPX Energy, Inc.
 Consolidated Balance Sheets
 (Unaudited)

	June 30, 2013 (Millions)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	\$90	\$153
Accounts receivable, net of allowance of \$9 million at June 30, 2013 and \$11 million at December 31, 2012	422	443
Deferred income taxes	27	17
Derivative assets	53	58
Inventories	76	66
Other	48	35
Total current assets	716	772
Investments	157	145
Properties and equipment (successful efforts method of accounting)	13,847	13,339
Less—accumulated depreciation, depletion and amortization	(5,378)	(4,923)
Properties and equipment, net	8,469	8,416
Derivative assets	20	2
Other noncurrent assets	121	121
Total assets	\$9,483	\$9,456
Liabilities and Equity		
Current liabilities:		
Accounts payable	\$515	\$509
Accrued and other current liabilities	159	203
Deferred income taxes	—	—
Derivative liabilities	27	14
Total current liabilities	701	726
Deferred income taxes	1,347	1,401
Long-term debt	1,688	1,508
Derivative liabilities	9	1
Asset retirement obligations	330	316
Other noncurrent liabilities	118	133
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; 200.6 million shares issued at June 30, 2013 and 199.3 million shares issued at December 31, 2012)	2	2
Additional paid-in-capital	5,499	5,487
Accumulated deficit	(321)	(223)
Accumulated other comprehensive income (loss)	(1)	2
Total stockholders' equity	5,179	5,268
Noncontrolling interests in consolidated subsidiaries	111	103
Total equity	5,290	5,371
Total liabilities and equity	\$9,483	\$9,456

See accompanying notes.

4

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

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Natural gas sales	\$316	\$312	\$583	\$669
Oil and condensate sales	151	122	290	228
Natural gas liquid sales	58	78	112	171
Total product revenues	525	512	985	1,068
Gas management	205	187	466	524
Net gain (loss) on derivatives not designated as hedges (Note 10)	78	71	(16) 85
Other	7	5	11	8
Total revenues	815	775	1,446	1,685
Costs and expenses:				
Lease and facility operating	73	67	148	134
Gathering, processing and transportation	111	120	218	255
Taxes other than income	36	25	71	55
Gas management, including charges for unutilized pipeline capacity	222	194	465	549
Exploration	20	19	39	38
Depreciation, depletion and amortization	227	248	458	476
Impairment of costs of acquired unproved reserves (Note 4)	—	65	—	117
General and administrative	74	71	146	139
Other—net	1	(2) 8	3
Total costs and expenses	764	807	1,553	1,766
Operating income (loss)	51	(32) (107) (81
Interest expense	(28) (26) (54) (52
Interest capitalized	1	3	2	5
Investment income and other	9	8	16	18
Income (loss) from continuing operations before income taxes	33	(47) (143) (110
Provision (benefit) for income taxes	11	(18) (52) (43
Income (loss) from continuing operations	22	(29) (91) (67
Income (loss) from discontinued operations	—	23	—	21
Net income (loss)	22	(6) (91) (46
Less: Net income attributable to noncontrolling interests	4	4	7	7
Net income (loss) attributable to WPX Energy	\$18	\$(10) \$(98) \$(53
Amounts attributable to WPX Energy, Inc.:				
Basic and diluted earnings (loss) per common share (Note 3):				
Income (loss) from continuing operations	\$0.09	\$(0.17) \$(0.49) \$(0.37
Income (loss) from discontinued operations	—	0.12	—	0.10
Net income (loss)	\$0.09	\$(0.05) \$(0.49) \$(0.27
Basic weighted-average shares (millions)	200.4	198.9	200.1	198.5
Diluted weighted-average shares (millions)	203.8	198.9	200.1	198.5
See accompanying notes.				

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

	Three months ended June 30, 2013		Six months ended June 30, 2013	
	2012	2012	2012	2012
	(Millions)			
Net income (loss) attributable to WPX Energy	\$ 18	\$(10)	\$(98)	\$(53)
Other comprehensive income (loss):				
Change in fair value of cash flow hedges, net of tax (a)	\$—	\$ 3	\$—	\$ 68
Net reclassifications into earnings of net cash flow hedge realized gains, net of tax (b)	—	(84)	(3)	(151)
Other comprehensive income (loss), net of tax	—	(81)	(3)	(83)
Comprehensive income (loss) attributable to WPX Energy	\$ 18	\$(91)	\$(101)	\$(136)

Change in fair value of cash flow hedges is net of \$2 million of income tax for the three months ended June 30, 2012 and \$39 million for the six months ended June 30, 2012. The six months ended June 30, 2012, includes a \$15 (a) million before tax unrealized gain that was recognized in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations, as the underlying transaction was no longer probable of occurring (see Note 10).

Net reclassifications into earnings of net cash flow hedge realized gains are net of \$48 million of income tax for the three months ended June 30, 2012 and \$2 million and \$87 million for the six months ended June 30, 2013 and (b) 2012, respectively. Before tax amounts realized and reclassified to product revenues, primarily natural gas product revenues, on the Consolidated Statements of Operations were \$132 million for the three months ended June 30, 2012 and \$5 million and \$238 million for the six months ended June 30, 2013 and 2012, respectively.

See accompanying notes.

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

	WPX Energy, Inc., Stockholders						
	Common Stock	Additional Paid-In- Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests in Consolidated Subsidiaries(a)	Total Equity
	(Millions)						
Balance at December 31, 2012	\$2	\$5,487	\$ (223)	\$ 2	\$ 5,268	\$ 103	\$5,371
Comprehensive income (loss):							
Net income (loss)	—	—	(98)	—	(98)	7	(91)
Other comprehensive loss	—	—	—	(3)	(3)	—	(3)
Comprehensive income (loss)							(94)
Stock based compensation	—	12	—	—	12	—	12
Contribution from noncontrolling interest					—	1	1
Balance at June 30, 2013	\$2	\$5,499	\$ (321)	\$ (1)	\$ 5,179	\$ 111	\$5,290

(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,		
	2013	2012	
	(Millions)		
Operating Activities			
Net income (loss)	\$(91) \$(46)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	458	483	
Deferred income tax provision (benefit)	(63) (56)
Provision for impairment of properties and equipment (including certain exploration expenses)	29	142	
Amortization of stock-based awards	17	15	
Gain on sale of assets	(5) (38)
Cash provided (used) by operating assets and liabilities:			
Accounts receivable	23	163	
Inventories	(9) 7	
Margin deposits and customer margin deposit payable	(5) (5)
Other current assets	(11) 6	
Accounts payable	9	(158)
Accrued and other current liabilities	(51) 29	
Changes in current and noncurrent derivative assets and liabilities	5	(59)
Other, including changes in other noncurrent assets and liabilities	(19) (42)
Net cash provided by operating activities	287	441	
Investing Activities			
Capital expenditures (a)	(548) (828)
Proceeds from sale of assets	10	306	
Purchases of investments	(3) (2)
Other	—	5	
Net cash used in investing activities	(541) (519)
Financing Activities			
Proceeds from common stock	2	1	
Proceeds from long-term debt	—	6	
Borrowings on credit facility	315	—	
Payments on credit facility	(135) —	
Other	9	(28)
Net cash provided by (used in) financing activities	191	(21)
Net decrease in cash and cash equivalents	(63) (99)
Cash and cash equivalents at beginning of period	153	526	
Cash and cash equivalents at end of period	\$90	\$427	
(a) Increase to properties and equipment	\$(540) \$(740)
Changes in related accounts payable	(8) (88)
Capital expenditures	\$(548) \$(828)
See accompanying notes.			

WPX Energy, Inc.

Notes to Consolidated Financial Statements

Note 1. General, Description of Business and Basis of Presentation

General

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, 2012 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, 2013, results of operations for the three and six months ended June 30, 2013 and 2012, changes in equity for the six months ended June 30, 2013 and cash flows for the six months ended June 30, 2013 and 2012.

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.

Description of Business

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

Domestic includes natural gas, oil and natural gas liquids ("NGL") development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. We specialize in development and production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Williston, Appalachian and Green River Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation, storage and related derivatives coupled with the sale of our commodity volumes.

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

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as "WPX" or the "Company" is at times referred to in the first person as "we", "us" or "our".

Basis of Presentation

Discontinued operations

During the second quarter of 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. The results of operations in 2012 for these holdings are reported as discontinued operations (see Note 2).

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

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date ("ASU 2013-04"). The amendments in ASU 2013-04 provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements from which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company is currently evaluating the impact of ASU 2013-04, but we do not anticipate a material impact to the Company's financial position, results of operations or cash flows as a result of applying this ASU.

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

Recently Adopted Provisions of U.S. GAAP

In accordance with U.S. GAAP, the following provisions, which had no material impact on the Company's financial position, results of operations or cash flows, were effective as of January 1, 2013:

The requirement to provide disclosures related to offsetting assets and liabilities, specifically as it relates to offsetting disclosures, wherein an entity must now make separate disclosures regarding the gross assets and liabilities, the offsetting amounts and the net assets and liabilities (see Note 10).

The requirement to present significant amounts reclassified out of Accumulated Other Comprehensive Income (Loss) ("AOCI") by the respective line items in the results of operations. See Note 10 and the Consolidated Statements of Comprehensive Income (Loss).

Note 2. Discontinued Operations

Summarized Results of Discontinued Operations in 2012

	Three months ended June 30, 2012 (Millions)	Six months ended June 30, 2012	
Revenues	\$6	\$26	
Income (loss) from discontinued operations before gain on sale and income taxes	\$1	\$(1)
Gain on sale	35	35	
Provision for income taxes	(13) (13)
Income from discontinued operations	\$23	\$21	

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

	Three months ended June 30, 2013		Six months ended June 30, 2012		
	2013	2012	2013	2012	
	(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	\$18	\$(33) \$(98) \$(74)
Basic weighted-average shares	200.4	198.9	200.1	198.5	
Effect of dilutive securities:					
Nonvested restricted stock units and awards	2.3	—	—	—	
Stock options	1.1	—	—	—	
Diluted weighted-average shares	203.8	198.9	200.1	198.5	
Earnings (loss) per common share from continuing operations:					
Basic	\$0.09	\$(0.17) \$(0.49) \$(0.37)
Diluted	\$0.09	\$(0.17) \$(0.49) \$(0.37)

For the three months ended June 30, 2012, 1.5 million weighted-average nonvested restricted stock units and awards and 1.0 million weighted-average stock options 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. Additionally, for the six months ended June 30, 2013 and 2012, 2.1 million and 2.0 million, respectively, weighted-average nonvested restricted stock units and awards and 1.0 million and 1.1 million, respectively, weighted-average stock options 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.

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

The table below includes information related to stock options that were outstanding at June 30, 2013 and 2012 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, 2013	2012
Options excluded (millions)	0.8	1.3
Weighted-average exercise price of options excluded	\$19.32	\$18.17
Exercise price range of options excluded	\$18.16 - \$20.97	\$16.46 - \$20.97
Second quarter weighted-average market price	\$17.86	\$15.92

Note 4. Impairments and Exploration Expenses

Impairment of cost of acquired unproved reserves

As a result of declines in forward natural gas prices during 2012 as compared to forward natural gas prices as of December 31, 2011, we performed impairment assessments of our capitalized cost of acquired unproved reserves during first and second quarters of 2012. Accordingly, we recorded \$52 million and \$65 million in impairments of capitalized costs of acquired unproved reserves primarily in the Powder River Basin in the first and second quarters of 2012, respectively. Our impairment analysis included an assessment of discounted future cash flows, which considered information obtained from drilling, other activities and natural gas reserve quantities (see Note 9).

Exploration Expenses

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
	(Millions)			
Geologic and geophysical costs	\$4	\$5	\$9	\$12
Dry hole costs	1	—	2	1
Unproved leasehold property impairment, amortization and expiration	15	14	28	25
Total exploration expenses	\$20	\$19	\$39	\$38

Note 5. Inventories

	June 30, 2013	December 31, 2012
	(Millions)	
Natural gas in underground storage	\$13	\$24
Material, supplies and other	63	42
	\$76	\$66

During the first quarter of 2013, we terminated two of three storage capacity agreements and sold the related natural gas.

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

Note 6. Debt and Banking Arrangements

As of the indicated dates, our debt consisted of the following:

	June 30, 2013	December 31, 2012
	(Millions)	
5.250% Senior Notes due 2017	\$400	\$400
6.000% Senior Notes due 2022	1,100	1,100
Credit facility agreement	180	—
Apco	8	8
Other	2	2
Total debt	\$1,690	\$1,510
Less: Current portion of long-term debt	2	2
Total long-term debt	\$1,688	\$1,508

We have a \$1.5 billion five-year senior unsecured revolving credit facility agreement (the “Credit Facility Agreement”) that expires in 2016. Under the terms of the Credit Facility Agreement and subject to certain requirements, we may request an increase in the commitments of up to an additional \$300 million by either commitments from new lenders or increased commitments from existing lenders. As of June 30, 2013, there was \$180 million borrowed under the Credit Facility Agreement, with a variable interest rate of 2.07 percent. Subsequent to June 30, 2013, we have borrowed an additional \$90 million under the Credit Facility Agreement.

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 Agreement. At June 30, 2013, a total of \$359 million in letters of credit have been issued.

Note 7. Provision (Benefit) for Income Taxes

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

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
	(Millions)			
Current:				
Federal	\$2	\$9	\$3	\$19
State	—	—	—	—
Foreign	4	5	8	8
	6	14	11	27
Deferred:				
Federal	3	(31) (59) (66
State	1	(1) (5) (4
Foreign	1	—	1	—
	5	(32) (63) (70
Total provision (benefit)	\$11	\$(18) \$(52) \$(43

The effective income tax rate of the total provision for the three months ended June 30, 2013, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations.

The effective income tax rate of the total benefit for the three months ended June 30, 2012, is greater than the federal statutory rate due primarily to state income taxes and taxes on foreign operations.

The effective income tax rate of the total benefit for the six months ended June 30, 2013, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations.

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

The effective income tax rate of the total benefit for the six months ended June 30, 2012, is greater than the federal statutory rate due primarily to state income taxes, taxes on foreign operations, and an adjustment to the minimum tax credit that was allocated to us by Williams as part of the separation from Williams.

As of June 30, 2013, 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 associated with a domestic or international matter will result in a significant increase or decrease of our unrecognized tax benefit.

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 is whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate litigating the second reserved claim in 2013. Plaintiffs have claimed damages of approximately \$20 million plus interest. However, we believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint alleges failure to pay royalty on hydrocarbons including drip condensate, fraud and misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons, violation of the New Mexico Oil and Gas Proceeds Payment Act, bad faith breach of contract and unjust enrichment. Plaintiffs seek monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter has been removed to the United States District Court for New Mexico. In August 2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico, violation of the New Mexico Oil and Gas Proceeds Payment Act and seek declaratory judgment, accounting and injunction. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

In February 2013, a potential class of royalty owners filed suit in Campbell County District Court, Wyoming, alleging violations of the Wyoming Royalty Payment Act by failing to properly and timely pay and report royalty and overriding royalty. Plaintiffs seek monetary damages, interest and penalties, and declaratory and injunctive relief. The case has been removed to Federal Court. At this time, we do not have a sufficient basis to calculate an estimated range of exposure related to this claim.

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 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

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

the issuance of additional guidance, ONRR has recently 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 2006 through June 2013, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately \$99 million.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that we have underpaid royalties due per the oil and gas leases with the State of New Mexico. In August 2011, the parties agreed to stay this matter pending the New Mexico Supreme Court's resolution of a similar matter involving a different producer. In April 2013, the court dismissed the case against WPX for lack of activity. At the same time the New Mexico Supreme Court ruled in favor of the producer in the related matter. The New Mexico State Land Office Commissioner has now indicated that they will not seek to re-file the complaint against WPX at this time.

Environmental matters

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

Matters related to Williams' former power business

In connection with the Separation and Distribution Agreement, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us, and we are obligated to pay Williams any net proceeds realized from, the pending or threatened litigation described below relating to the 2000-2001 California energy crisis and the reporting of certain natural gas-related information to trade publications.

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission ("FERC"). We have entered into settlements with the State of California ("State Settlement"), major California utilities ("Utilities Settlement") and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We currently have a settlement agreement in principle with certain California utilities aimed at eliminating and substantially reducing this exposure. Once finalized, the settlement agreement will also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement will resolve most, if not all, of our legal issues arising from the 2000-2001 California energy crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of natural gas-related information to trade publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, seeking unspecified amounts of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin and brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008,

the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs' lack of standing. On January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal and entered judgment in our favor. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

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

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs' state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion on the Western States Antitrust Litigation. The panel held that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims, reversing the summary judgment entered in favor of the defendants. The panel further held that the district court did not abuse its discretion in denying the plaintiffs' motions for leave to amend complaints. The Ninth Circuit granted an order staying the mandate for a period of ninety (90) days pending defendants' consideration of whether to file a petition for writ of certiorari with the U.S. Supreme Court. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time.

Other Indemnifications

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

At June 30, 2013, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

Summary

As of June 30, 2013 and December 31, 2012, the Company had accrued approximately \$16 million and \$18 million, respectively, for loss contingencies associated with royalty litigation, reporting of natural gas information to trade publications and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

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 and restricted cash approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	June 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)							
Energy derivative assets	\$18	\$54	\$1	\$73	\$20	\$38	\$2	\$60
	\$15	\$19	\$2	\$36	\$11	\$1	\$3	\$15

Energy derivative liabilities

Long-term debt (a)	\$—	\$1,710	\$—	\$1,710	\$—	\$1,617	\$—	\$1,617
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(a) The carrying value of long-term debt, excluding capital leases, was \$1,687 million and \$1,508 million as of June 30, 2013 and December 31, 2012, 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

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

a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

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

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

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

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the net fair value of our derivatives portfolio expiring at the end of 2014. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at June 30, 2013, consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers occurred during the periods ended June 30, 2013 and 2012.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended June 30, 2013		Six months ended June 30, 2013		
	2013	2012	2013	2012	
	(Millions)				
Beginning balance	\$ (1) \$ (1) \$ (1) \$ 1	
Realized and unrealized gain (loss):					
Included in income (loss) from continuing operations	—	2	—	3	
Purchases, issuances, and settlements	—	(1) —	(4)
Ending balance	\$ (1) \$ —	\$ (1) \$ —	

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Unrealized gain (loss) included in income (loss)
from continuing operations relating to instruments \$(1) \$1 \$(1) \$—
still held at June 30

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

16

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

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Total losses for the six months ended June 30,		
	2013	2012	
	(Millions)		
Impairments:			
Costs of acquired unproved reserves (see Note 4)	\$—	\$117	(a)

(a) Due to significant declines in forward natural gas prices during 2012, we assessed the carrying value of our natural gas costs of acquired unproved reserves for impairments. Most of the impairment charge is related to costs of acquired unproved reserves in the Powder River Basin. Our assessment utilized estimates of future discounted cash flows. Significant judgments and assumptions in these assessments include estimates of probable and possible reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, future natural gas liquids prices, expectation for market participant drilling plans, expected capital costs and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.

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

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

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

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

The following table sets forth the derivative volumes that are economic hedges of production volumes as well as the table depicts the notional amounts of the net long (short) positions which do not represent economic hedges of our production, both which are included in our commodity derivatives portfolio as of June 30, 2013.

Derivatives related to production

Commodity	Period	Contract Type(a)	Location	Notional Volume (b)	Weighted Average Price(c)
Crude Oil	Jul-Dec 2013	Fixed Price Swaps	WTI	(8,500) \$100.70
Crude Oil	Jul-Dec 2013	Fixed Price Swaps	LLS	(500) \$109.40
Natural Gas	Jul-Dec 2013	Fixed Price Swaps	Henry Hub	(470) \$3.59
Natural Gas	Jul-Dec 2013	Basis Swaps	Northeast	(99) \$0.21
Natural Gas	Jul-Dec 2013	Basis Swaps	Mid-Con	(30) \$(0.17)
Natural Gas	Jul-Dec 2013	Basis Swaps	Rockies	(20) \$(0.15)
Crude Oil	2014	Fixed Price Swaps	WTI	(3,000) \$93.90
Natural Gas	2014	Fixed Price Swaps	Henry Hub	(40) \$4.35
Natural Gas	2014	Swaptions	Henry Hub	(40) \$4.35
Natural Gas	2014	Costless Collars	Henry Hub	(145) \$ 4.00 - 4.66

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type(d)	Location(e)	Notional Volume (b)	Weighted Average Price(f)
Natural Gas	Jul-Dec 2013	Fixed Price Swaps	Multiple	(3) —
Natural Gas	Jul-Dec 2013	Basis Swaps	Multiple	(20) —
Natural Gas	Jul-Dec 2013	Index	Multiple	(99) —
Natural Gas	2014	Fixed Price Swaps	Multiple	(11) —
Natural Gas	2014	Basis Swaps	Multiple	(3) —
Natural Gas	2014	Index	Multiple	(82) —
Natural Gas	2015	Index	Multiple	(41) —
Natural Gas	2016	Index	Multiple	2	—
Natural Gas	2017	Index	Multiple	2	—

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

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

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

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

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, 2013		December 31, 2012	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production designated as hedging instruments	\$—	\$—	\$5	\$—
Not designated as hedging instruments:				
Derivatives related to production not designated as hedging instruments	56	19	33	—
Legacy natural gas contracts from former power business	1	1	2	2
All other	16	16	20	13
Total derivatives not designated as hedging instruments	73	36	55	15
Total derivatives	\$73	\$36	\$60	\$15

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in AOCI or revenues.

	Three months ended June 30,		Six months ended June 30,		Classification
	2013	2012	2013	2012	
	(Millions)				
Net gain recognized in other comprehensive income (loss) (effective portion)	\$—	\$5	\$—	\$107	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion) (a)	\$—	\$132	\$5	\$238	Revenues
Loss recognized in income (ineffective portion)	\$—	\$1	\$—	\$—	Revenues

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

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

The following table presents pre-tax gains and losses recognized in revenues for our energy commodity derivatives not designated as hedging instruments.

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
	(Millions)			
Unrealized gain (loss)	\$98	\$60	\$(5) \$59

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Realized gain (loss)	(20) 11	(11) 26
Net gain (loss)	\$78	\$71	\$(16) \$85

The cash flow impact of our unrealized loss on 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.

	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted(Received)	Net Amount
June 30, 2013				
Derivative assets with right of offset or master netting agreements	\$73	\$(33)	\$ —	\$40
Derivative liabilities with right of offset or master netting agreements	\$(36)	\$33	\$ —	\$(3)
December 31, 2012				
Derivative assets with right of offset or master netting agreements	\$60	\$(10)	\$(2)	\$48
Derivative liabilities with right of offset or master netting agreements	\$(15)	\$10	\$ —	\$(5)

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.

- (a) 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, 2013, we had a net \$3 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 \$3 million.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. During the first quarter of 2012, approximately \$15 million of unrealized gains were recognized into earnings in 2012 for hedge transactions where the underlying transactions were no longer probable of occurring due to the sale of our Barnett Shale properties. The \$15 million gain is included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations for 2012. As of June 30, 2013, no derivatives were designated as cash flow hedges.

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.

20

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

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2013, 2012 and 2011, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

The gross and net credit exposure from our derivative contracts as of June 30, 2013, is summarized as follows:

Counterparty Type	Gross	Gross Total	Net	Net Total
	Investment Grade (a) (Millions)		Investment Grade (a)	
Energy marketers and traders and other	\$1	\$1	\$1	\$1
Financial institutions	72	72	39	39
	\$73	73	\$40	40
Credit reserves		—		—
Credit exposure from derivatives		\$73		\$40

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

Our seven largest net counterparty positions represent approximately 94 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, we, nor the participating financial institutions, are required to provide collateral support related to hedging activities.

At June 30, 2013, we did not hold any collateral support, either in the form of cash or letters of credit, related to our other derivative positions.

Note 11. Segment Disclosures

Our reporting segments are domestic and international (see Note 1).

Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and international maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

Performance Measurement

We evaluate performance based upon segment revenues and segment operating income (loss). There are no intersegment sales between domestic and international.

The following tables reflect the reconciliation of segment revenues and segment operating income (loss) to revenues and operating income (loss) as reported in the Consolidated Statements of Operations.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements—(Continued)

	Domestic	International (Millions)	Total	
Three months ended June 30, 2013				
Total revenues	\$773	\$42	\$815	
Costs and expenses:				
Lease and facility operating	\$63	\$10	\$73	
Gathering, processing and transportation	110	1	111	
Taxes other than income	30	6	36	
Gas management, including charges for unutilized pipeline capacity	222	—	222	
Exploration	17	3	20	
Depreciation, depletion and amortization	217	10	227	
General and administrative	69	5	74	
Other—net	5	(4) 1	
Total costs and expenses	\$733	\$31	\$764	
Operating income (loss)	\$40	\$11	\$51	
Interest expense	(28) —	(28)
Interest capitalized	1	—	1	
Investment income and other	2	7	9	
Income (loss) from continuing operations before income taxes	\$15	\$18	\$33	
Three months ended June 30, 2012				
Total revenues	\$741	\$34	\$775	
Costs and expenses:				
Lease and facility operating	\$60	\$7	\$67	
Gathering, processing and transportation	120	—	120	
Taxes other than income	18	7	25	
Gas management, including charges for unutilized pipeline capacity	194	—	194	
Exploration	16	3	19	
Depreciation, depletion and amortization	242	6	248	
Impairment of costs of acquired unproved reserves (Note 4)	65	—	65	
General and administrative	68	3	71	
Other—net	—	(2) (2)
Total costs and expenses	\$783	\$24	\$807	
Operating income (loss)	\$(42) \$10	\$(32)
Interest expense	(26) —	(26)
Interest capitalized	3	—	3	
Investment income and other	—	8	8	
Income (loss) from continuing operations before income taxes	\$(65) \$18	\$(47)

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

	Domestic	International (Millions)	Total
Six months ended June 30, 2013			
Total revenues	\$1,368	\$78	\$1,446
Costs and expenses:			
Lease and facility operating	\$130	\$18	\$148
Gathering, processing and transportation	216	2	218
Taxes other than income	59	12	71
Gas management, including charges for unutilized pipeline capacity	465	—	465
Exploration	35	4	39
Depreciation, depletion and amortization	441	17	458
General and administrative	138	8	146
Other—net	11	(3)	8
Total costs and expenses	\$1,495	\$58	\$1,553
Operating income (loss)	\$(127)) \$20	\$(107)
Interest expense	(54)) —	(54)
Interest capitalized	2	—	2
Investment income and other	4	12	16
Income (loss) from continuing operations before income taxes	\$(175)) \$32	\$(143)
Six months ended June 30, 2012			
Total revenues	\$1,620	\$65	\$1,685
Costs and expenses:			
Lease and facility operating	\$121	\$13	\$134
Gathering, processing and transportation	255	—	255
Taxes other than income	43	12	55
Gas management, including charges for unutilized pipeline capacity	549	—	549
Exploration	30	8	38
Depreciation, depletion and amortization	464	12	476
Impairment of costs of acquired unproved reserves (Note 4)	117	—	117
General and administrative	133	6	139
Other—net	5	(2)	3
Total costs and expenses	\$1,717	\$49	\$1,766
Operating income (loss)	\$(97)) \$16	\$(81)
Interest expense	(52)) —	(52)
Interest capitalized	5	—	5
Investment income and other	2	16	18
Income (loss) from continuing operations before income taxes	\$(142)) \$32	\$(110)
Total assets			
Total assets as of June 30, 2013	\$9,117	\$366	\$9,483
Total assets as of December 31, 2012	\$9,113	\$343	\$9,456

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 2012 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.

Overview

The following table presents our production volumes and financial highlights for the three and six months ended June 30, 2013 and 2012:

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
Production Sales Data:				
Domestic natural gas (MMcf)	90,022	102,163	180,433	203,509
Domestic oil (MBbls)	1,373	1,123	2,614	2,071
Domestic NGLs (MBbls)	1,895	2,779	3,802	5,525
Domestic combined equivalent volumes (MMcfe) (a)	109,628	125,574	218,931	249,084
Domestic per day combined equivalent volumes (MMcfe/d)	1,205	1,380	1,210	1,369
Domestic combined equivalent volumes (MBoe)	18,271	20,929	36,489	41,514
International combined equivalent volumes (MMcfe) (a)(b)	5,202	5,362	9,977	10,414
International per day combined equivalent volumes (MMcfe/d)	57	59	55	57
Financial Data (millions):				
Total domestic revenues	\$773	\$741	\$1,368	\$1,620
Total international revenues	\$42	\$34	\$78	\$65
Consolidated operating income (loss)	\$51	\$(32)	\$(107)	\$(81)
Consolidated capital expenditures	\$277	\$400	\$548	\$828

(a) Oil and NGLs were converted to MMcfe using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.

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

Our second quarter 2013 operating results were \$83 million favorable compared to second quarter 2012. The primary favorable impacts include \$154 million of higher realized natural gas prices, the absence of \$65 million of impairments of costs of acquired unproved reserves primarily in the Powder River Basin recorded in 2012 and \$21 million lower depreciation, depletion and amortization reflecting both lower production volumes and a \$9 million downward adjustment related to an increase in our estimated proved reserves. Unfavorable impacts to our quarter over quarter operating results include the absence of \$130 million of gains realized in 2012 on natural gas derivatives designated as hedges and the impact to revenues of lower natural gas and natural gas liquids volumes.

Our year to date 2013 operating results were \$26 million unfavorable compared to year to date 2012. The primary unfavorable impacts include the absence of \$239 million of gains realized in 2012 on natural gas derivatives designated as hedges, \$101 million unfavorable change in derivatives not designated as hedges and lower natural gas

production volumes. Operating results were favorably impacted by \$194 million higher realized natural gas prices and the absence of \$117 million of impairments of costs of acquired unproved reserves primarily in the Powder River Basin recorded in 2012.

Outlook

For the remainder of 2013, we will focus on growing our oil production and developing oil reserves, primarily those located in the Williston Basin, specifically on the development of reserves in the middle Bakken and upper Three Forks formations of this basin. Continued Williston Basin operational improvements should facilitate seven additional wells drilled and eleven additional wells completed than originally planned for 2013.

We will also remain disciplined in the development of our natural gas reserves. We will continue to focus our natural gas drilling effort in the NGL rich Piceance Basin, because of our scale and efficiency of that operation, together with significant infrastructure already in place. We are moving to increase our natural gas volumes over current production by maintaining seven drilling rigs in the Piceance Basin for the remainder of the year. The seven rigs are two greater than originally planned for the remainder of 2013. In the Appalachian Basin, we will initially focus on completing our inventory of drilled locations. Our drilling program in the Appalachian Basin will be limited. Specifically, drilling capital in Susquehanna County will be minimal due to infrastructure constraints on our third party gatherer's system. Until those constraints have been rectified, we will look to develop opportunities in Westmoreland County in the Appalachian Basin.

We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities and negotiated cost savings on vendor contracts. Additionally, more favorable, previously negotiated gathering and processing contract provisions became effective in 2013.

We will look to deploy 8 percent to 10 percent of our estimated annual capital spending on exploratory activities, primarily focused on oil. WPX is initiating oil development in New Mexico's San Juan Basin after exploratory drilling yielded commercially economic results from the Gallup Sandstone in the Mancos formation. For the remainder of 2013, we expect to drill additional wells in the Gallup Sandstone and test wells in another new area. We will also continue to look at purchasing land in these and other areas. Additionally, our Niobrara Shale discovery well in the Piceance Basin exceeded 1.4 billion cubic feet of natural gas production in the first 180 days of operation. We finished drilling our second Niobrara Shale well and expect initial production in the third quarter with plans to drill three additional wells in 2013.

We anticipate our total capital spending in 2013 will be approximately \$1.2 billion. Through June 30, 2013, our capital expenditures totaled \$548 million.

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

- Continuing to invest in and grow our production and reserves;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position, Gallup Sandstone oil play and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- Fully delineate the Niobrara Shale discovery through drilling and 3-D seismic;
- Continuing to pursue cost improvements and efficiency gains;
- Retaining the flexibility to make adjustments to our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities; and
- Continuing to maintain an active economic hedging program around our commodity price risks.

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

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

We have seen improvement in natural gas prices during first half of 2013. Should this improvement not continue, we would need to either reduce our capital spending or utilize more of our credit facility, or a combination of both. We

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

From time to time, we may consider strategic acquisitions or dispositions of assets that could be material to our financial condition or results of operations. We have completed a data room process for our holdings in Wyoming's Powder

River Basin. In management's view, retaining ownership of the assets at the present time represents greater value for shareholders than the bids received. We remain open to the potential sale or partial monetization of these assets in the future.

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 the remainder of 2013, we have the following contracts as of the date of this filing shown at weighted average volumes and basin-level weighted average prices:

	Jul - Dec 2013 Natural Gas	
	Volume	Weighted Average
	(BBtu/d)	Price (\$/MMBtu)
Natural gas fixed-price—Henry Hub	470	\$ 3.59
Basis swaps—Northeast	99	\$ 0.21
Basis swaps—Mid-Continent	30	\$ (0.17)
Basis swaps—Rockies	20	\$ (0.15)
	Jul - Dec 2013 Crude Oil	
	Volume	Weighted Average
	(Bbls/d)	Price (\$/Bbl)
Crude oil fixed-price—WTI	8,500	\$ 100.70
Crude oil fixed-price—LLS	1,826	\$ 107.11

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to deliver on a firm basis 200,000 MMBtu/d of natural gas at monthly index pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation, which expires in 2014.

Results of Operations

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

Domestic includes natural gas, oil and natural gas liquids development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. Our development and production techniques specialize in production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Williston, Appalachian and Green River Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation, storage and related derivatives coupled with the sale of our commodity volumes.

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

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Most all of our commodity derivative contracts entered into after 2011 continue to serve as economic hedges but are not designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2012 that are included in accumulated other comprehensive income were realized during first-quarter 2013.

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended June 30, 2013 (Millions)	2012	\$ Change	% Change	
Domestic revenues:					
Natural gas sales	\$310	\$307	\$3	1	%
Oil and condensate sales	121	95	26	27	%
Natural gas liquid sales	58	77	(19)	(25))%
Total product revenues	489	479	10	2	%
Gas management	205	187	18	10	%
Net gain (loss) on derivatives not designated as hedges	78	71	7	10	%
Other	1	4	(3)	(75))%
Total domestic revenues	\$773	\$741	\$32	4	%
Total international revenues	\$42	\$34	\$8	24	%
Total revenues	\$815	\$775	\$40	5	%

Domestic Revenues

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

\$3 million increase in natural gas sales primarily due to \$154 million related to higher sales prices offset by the absence of \$130 million of realized gains in 2012 from derivatives designated as hedges and \$21 million related to lower volumes. The Company no longer designated derivatives entered into after December 31, 2011 as hedges beginning in 2012. The average realized price per Mcf (excluding hedges) was \$3.45 for the three months ended June 30, 2013 compared to \$1.74 for the three months ended June 30, 2012 on production sales volumes of 90,022 MMcf and 102,163 MMcf for the three months ended June 30, 2013 and 2012, respectively. Including the impact of realized gains designated as hedges, our natural gas price per Mcf was \$3.45 compared to \$3.01 for the three months ended June 30, 2013 and 2012, respectively. We also incurred \$25 million in 2013 of realized losses on natural gas derivatives that were not designated as hedges; however these losses are included in net gain (loss) on derivatives not designated as hedges and discussed below. The decrease in our production sales volumes is due in part to our disciplined development of natural gas reserves in a low natural gas price environment. However, natural gas production in the Appalachian Basin has increased and third party infrastructure constraints are starting to be resolved and we have plans to increase drilling in the Piceance Basin that will increase production.

\$26 million increase in oil and condensate sales reflects increased production sales volumes of 1,373 Mbbls compared to 1,123 Mbbls as well as increased price per barrel of \$87.76 compared to \$83.89 (including the impact of hedges in 2012) for the three months ended June 30, 2013 and 2012, respectively. The increase in production sales volumes primarily relate to increased production in the Williston Basin where the per day volumes were 12.3 MBbls per day for second quarter 2013 compared to 9.5 MBbls per day for the same period in 2012.

\$19 million decrease in natural gas liquids sales reflects decreased production sales volumes of 1,895 Mbbls for the three months ended June 30, 2013 compared to 2,779 Mbbls for the same period in 2012, part of this decrease relates to lower ethane recovery rates as a result of ethane prices in the Piceance Basin during 2013. The average per barrel price for natural gas liquids was \$30.21 compared to \$27.96 for the three months ended June 30, 2013 and 2012, respectively, and reflects a change in the composition of the barrel due to lower ethane recovery rates.

\$18 million increase in gas management revenues primarily due to an 81 percent increase in average prices on physical natural gas sales partially offset by 29 percent lower natural gas sales volumes. We experienced an increase of \$28 million in related gas management costs and expenses.

\$7 million change in net gain (loss) on derivatives not designated as hedges reflects the following:

	Three months ended June 30,	
	2013	2012
	(Millions)	
Unrealized gain (loss)	\$98	\$60
Realized gain (loss)	(20) 11
Net gain (loss)	\$78	\$71

The net realized loss in 2013 primarily reflects \$25 million related to natural gas derivatives. The unrealized mark-to-market gains in 2013 primarily related to natural gas derivatives and the gains in 2012 related to crude derivatives.

International Revenues

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

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

	Three months ended June 30,		\$ Change	% Change	
	2013	2012			
	(Millions)				
Domestic costs and expenses:					
Lease and facility operating	\$63	\$60	\$(3) (5)%
Gathering, processing and transportation	110	120	10	8	%
Taxes other than income	30	18	(12) (67)%
Gas management, including charges for unutilized pipeline capacity	222	194	(28) (14)%
Exploration	17	16	(1) (6)%
Depreciation, depletion and amortization	217	242	25	10	%
Impairment of costs of acquired unproved reserves	—	65	65	100	%
General and administrative	69	68	(1) (1)%
Other—net	5	—	(5) NM	
Total domestic costs and expenses	\$733	\$783	\$50	6	%
International costs and expenses:					
Lease and facility operating	\$10	\$7	\$(3) (43)%
Gathering, processing and transportation	1	—	(1) NM	
Taxes other than income	6	7	1	14	%
Exploration	3	3	—	—	%
Depreciation, depletion and amortization	10	6	(4) (67)%
General and administrative	5	3	(2) (67)%
Other—net	(4) (2) 2	(100)%
Total international costs and expenses	\$31	\$24	\$(7) (29)%
Total costs and expenses	\$764	\$807	\$43	5	%
Domestic operating income (loss)	\$40	\$(42) \$82	NM	
International operating income	\$11	\$10	\$1	10	%

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

Domestic Costs

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

Lease and facility operating expense averaged \$0.59 per Mcfe for the three months ended June 30, 2013 compared to \$0.47 for the same period in 2012. The increase in the rate per Mcfe primarily relates to the impact of increased Williston Basin production in relation to our overall portfolio, along with higher workover expense and increased water disposal costs resulting from decreased drilling and the corresponding utilization of produced water in the well hydraulic fracturing process.

\$10 million decrease in gathering, processing and transportation charges primarily related to lower volumes and the effect of new favorable contract terms for gathering and processing services in the Piceance Basin. Gathering, processing and transportation expenses averaged \$1.00 per Mcfe compared to \$0.95 per Mcfe for the three months ended June 30, 2013 and 2012, respectively.

\$12 million increase in taxes other than income primarily relates to the increase in natural gas prices (excluding derivatives) for 2013 compared to 2012. Taxes other than income averaged \$0.27 per Mcfe for the second quarter 2013 compared to \$0.15 per Mcfe for the same period in 2012.

\$28 million increase in gas management expenses, primarily due to a 98 percent increase in average prices on physical natural gas cost of sales partially offset by 29 percent lower natural gas sales volumes. Also included in gas management expenses are \$14 million and \$12 million for the three months ended June 30, 2013 and 2012, respectively, for unutilized pipeline capacity.

\$25 million decrease in depreciation, depletion and amortization primarily due to lower volumes for 2013 compared to 2012. During second quarter 2013, we increased our proved reserves used for the calculation of depletion and amortization to reflect the impact of an increase in the 12 month average price as of June 30, 2013. This resulted in a \$9 million downward adjustment to depreciation, depletion and amortization expense for the second quarter 2013.

During the three months ended June 30, 2013, our depreciation, depletion and amortization averaged \$1.98 per Mcfe compared to an average \$1.93 per Mcfe for the same period in 2012.

\$65 million of property impairments of cost of acquired unproved reserves were included for the three months ended June 30, 2012, as previously discussed.

International costs

International costs increased primarily due to higher depreciation, depletion and amortization costs related to our Colombian operations which began production in the third quarter of 2012 as well as higher lease and facility operating costs.

Consolidated results below operating income (loss)

	Three months ended June 30,		\$ Change	% Change	
	2013	2012			
	(Millions)				
Consolidated operating income (loss)	\$51	\$(32)) \$83	NM	
Interest expense	(28)) (26)) (2)) 8	%
Interest capitalized	1	3	(2)) (67))%
Investment income and other	9	8	1	13	%
Income (loss) from continuing operations before income taxes	33	(47)) 80	NM	
Provision (benefit) for income taxes	11	(18)) (29)) NM	
Income (loss) from continuing operations	22	(29)) 51	NM	
Income (loss) from discontinued operations	—	23	(23)) 100	%
Net income (loss)	22	(6)) 28	NM	
Less: Net income attributable to noncontrolling interests	4	4	—	—	%
Net income (loss) attributable to WPX Energy	\$ 18	\$(10)) \$28	NM	

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

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

Income taxes changed unfavorably due to the pre-tax income for second quarter 2013 compared to pre-tax loss for second quarter 2012. 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.

Six Month-Over-Six Month Results of Operations

Revenue Analysis

	Six months ended June 30, 2013 2012 (Millions)		\$ Change	% Change	
Domestic revenues:					
Natural gas sales	\$573	\$660	\$(87)	(13))%
Oil and condensate sales	232	175	57	33)%
Natural gas liquid sales	111	169	(58)	(34))%
Total product revenues	916	1,004	(88)	(9))%
Gas management	466	524	(58)	(11))%
Net gain (loss) on derivatives not designated as hedges	(16)) 85	(101))	NM
Other	2	7	(5)	(71))%
Total domestic revenues	\$1,368	\$1,620	\$(252)	(16))%
Total international revenues	\$78	\$65	\$13	20)%
Total revenues	\$1,446	\$1,685	\$(239)	(14))%

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

Domestic Revenues

Significant variances in the respective line items of domestic revenues are comprised of the following: \$87 million decrease in natural gas sales primarily due to the absence of \$239 million of realized gains from derivatives designated as hedges and \$48 million related to lower volumes, partially offset by a \$194 million increase related to higher prices (excluding hedges). The Company no longer designated derivatives entered into after December 31, 2011 as hedges beginning in 2012. The average realized price per Mcf (excluding hedges) was \$3.15 for the six months ended June 30, 2013 compared to \$2.07 for the six months ended June 30, 2012 on production sales volumes of 180,433 MMcf and 203,509 MMcf for the six months ended June 30, 2013 and 2012, respectively. Including the impact of realized gains on derivatives designated as hedges, our natural gas price per Mcf was \$3.18 compared to \$3.25 for the six months ended June 30, 2013 and 2012, respectively. The decrease in our production sales volumes is due in part to our disciplined development of natural gas reserves in a low natural gas price environment. However, natural gas production in the Appalachian Basin has increased and third party infrastructure constraints are starting to be resolved and we have plans to increase drilling in the Piceance Basin that will increase production.

\$57 million increase in oil and condensate sales reflects increased production sales volumes of 2,614 Mbbls compared to 2,071 Mbbls as well as increased price per barrel of \$88.71 compared to \$84.19 (including the impact of hedges in 2012) for the six months ended June 30, 2013 and 2012, respectively. The increase in production sales volumes primarily relate to increased production in the Williston Basin where the volumes were 11.9 MBbls per day for the first six months 2013 compared to 8.6 MBbls per day for the same period in 2012.

\$58 million decrease in natural gas liquids sales reflects decreased production sales volumes of 3,802 Mbbls for the six months ended June 30, 2013 compared to 5,525 Mbbls for the same period in 2012, part of this decrease relates to lower ethane recovery rates as a result of ethane prices in the Piceance Basin during 2013. The average per barrel

price for natural gas liquids was \$29.21 compared to \$30.69 for the six months ended

30

June 30, 2013 and 2012 respectively, and reflects a change in the composition of the barrel due to lower ethane recovery rates.

\$58 million decrease in gas management revenues primarily due to 41 percent lower natural gas sales volumes partially offset by a 63 percent increase in average prices on physical natural gas sales. We experienced a decrease of \$84 million in related gas management costs and expenses.

\$101 million change in net gain (loss) on derivatives not designated as hedges reflects the following:

	Six months ended June 30,	
	2013	2012
	(Millions)	
Unrealized gain (loss)	\$ (5) \$ 59
Realized gain (loss)	(11) 26
Net gain (loss)	\$(16) \$ 85

The net realized loss in 2013 primarily reflects \$25 million related to natural gas derivatives. The unrealized mark-to-market gains in 2012 primarily related to crude derivatives.

International Revenues

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

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

	Six months ended June 30,		\$ Change	% Change	
	2013	2012			
	(Millions)				
Domestic costs and expenses:					
Lease and facility operating	\$ 130	\$ 121	\$(9) (7)%
Gathering, processing and transportation	216	255	39	15	%
Taxes other than income	59	43	(16) (37)%
Gas management, including charges for unutilized pipeline capacity	465	549	84	15	%
Exploration	35	30	(5) (17)%
Depreciation, depletion and amortization	441	464	23	5	%
Impairment of costs of acquired unproved reserves	—	117	117	100	%
General and administrative	138	133	(5) (4)%
Other—net	11	5	(6) (120)%
Total domestic costs and expenses	\$ 1,495	\$ 1,717	\$ 222	13	%
International costs and expenses:					
Lease and facility operating	\$ 18	\$ 13	\$(5) (38)%
Gathering, processing and transportation	2	—	(2) NM	
Taxes other than income	12	12	—	—	%
Exploration	4	8	4	50	%
Depreciation, depletion and amortization	17	12	(5) (42)%
General and administrative	8	6	(2) (33)%
Other—net	(3) (2) 1	(50)%
Total international costs and expenses	\$ 58	\$ 49	\$(9) (18)%
Total costs and expenses	\$ 1,553	\$ 1,766	\$ 213	12	%
Domestic operating income (loss)	\$(127) \$(97) \$(30) 31	%
International operating income	\$ 20	\$ 16	\$ 4	25	%

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

31

Domestic Costs

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

\$9 million increase in lease and facility operating expense primarily relating to higher workover expense, increased water disposal costs resulting from decreased drilling and the corresponding utilization of produced water in the well hydraulic fracturing process as well as decreased production. Lease and facility operating expense averaged \$0.60 per Mcfe for the six months ended June 30, 2013 compared to \$0.48 for the same period in 2012 and the increase partially reflects the growth of Williston Basin in relation to the total.

\$39 million decrease in gathering, processing and transportation charges primarily related to lower volumes and the effect of new favorable contract terms for gathering and processing services in the Piceance Basin. Gathering, processing and transportation charges averaged \$0.99 per Mcfe compared to \$1.02 per Mcfe for the six months ended June 30, 2013 and 2012.

\$16 million increase in taxes other than income primarily relates to the increase in natural gas prices for 2013 compared to 2012. Taxes other than income averaged \$0.27 per Mcfe for the first six months of 2013 compared to \$0.17 per Mcfe for the same period in 2012.

\$84 million decrease in gas management expenses, primarily due to 41 percent lower natural gas sales volumes partially offset by a 59 percent increase in average prices on physical natural gas cost of sales. Also included in gas management expenses are \$27 million and \$23 million for the six months ended June 30, 2013 and 2012, respectively, for unutilized pipeline capacity. Gas management expenses for the period ended June 30, 2012 also includes \$11 million related to lower of cost or market charges to the carrying value of natural gas inventories in storage.

\$23 million decrease in depreciation, depletion and amortization primarily due to lower volumes in 2013 compared to 2012. During second quarter 2013, we increased our proved reserves used for the calculation of depletion and amortization to reflect the impact of an increase in the 12 month average price as of June 30, 2013. This resulted in a \$9 million downward adjustment to depreciation, depletion and amortization expense for the six months ended June 30, 2013. During the six months ended June 30, 2013, our depreciation, depletion and amortization averaged \$2.01 per Mcfe compared to an average \$1.87 per Mcfe for the same period in 2012.

\$117 million of property impairments of cost of acquired unproved reserves were included for the six months ended June 30, 2012, as previously discussed.

International costs

International costs increased primarily due to higher depreciation, depletion and amortization costs related to our Colombian operations which began production in the third quarter of 2012 as well as higher lease and facility operating costs. These increases were partially offset by lower exploration expense for the first half of 2013 compared to the first half of 2012.

Consolidated results below operating income (loss)

	Six months ended June 30,		\$ Change	% Change	
	2013	2012			
	(Millions)				
Consolidated operating income (loss)	\$ (107)) \$ (81)) \$ (26)) 32	%
Interest expense	(54)) (52)) (2)) 4	%
Interest capitalized	2) 5	(3)) (60))%
Investment income and other	16) 18	(2)) (11))%
Income (loss) from continuing operations before income taxes	(143)) (110)) (33)) (30))%
Provision (benefit) for income taxes	(52)) (43)) 9) 21	%
Income (loss) from continuing operations	(91)) (67)) (24)) (36))%
Income (loss) from discontinued operations	—) 21	(21)) 100	%
Net income (loss)	(91)) (46)) (45)) (98))%
Less: Net income attributable to noncontrolling interests	7) 7	—	—	%
Net income (loss) attributable to WPX Energy	\$ (98)) \$ (53)) \$ (45)) (85))%

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

32

Benefit for income taxes changed favorably due to the greater pre-tax loss in 2013 compared to 2012. 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.

Management's Discussion and Analysis of Financial Condition and Liquidity

Outlook

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures, and tax and debt payments while maintaining a sufficient level of liquidity. Our primary sources of liquidity in 2013 will continue to be expected cash flow from operations and borrowings on our \$1.5 billion credit facility. The combination of these sources should be sufficient to allow us to pursue our business strategy and goals for the remainder of 2013.

We note the following assumptions for the remainder of 2013:

- Our capital expenditures, including international, are estimated to be approximately \$1.2 billion in 2013, and are generally considered to be largely discretionary; and

- Apco's liquidity requirements will continue to be provided from its cash flows from operations and cash on hand. Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;

- Higher than expected collateral obligations that may be required, including those required under new commercial agreements;

- Significantly lower than expected capital expenditures could result in the loss of undeveloped leaseholds; and

- Reduced access to our credit facility.

Liquidity

We plan to conservatively manage our balance sheet and our level of capital spending. 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 2013. 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.

Sources (Uses) of Cash

	Six months ended June 30,	
	2013	2012
	(Millions)	
Net cash provided (used) by:		
Operating activities	\$287	\$441
Investing activities	(541)	(519)
Financing activities	191	(21)
Decrease in cash and cash equivalents	\$(63)	\$(99)
Operating activities		

Our net cash provided by operating activities for the six months ended June 30, 2013 decreased from the same period in 2012 primarily due to the decrease in our operating results driven by lower natural gas and NGL sales revenues.

Investing activities

Significant transactions include expenditures for drilling and completion of \$450 million and \$695 million for the six months ended June 30, 2013 and 2012, respectively. Also included in 2012 are proceeds from the sale of the Barnett and Arkoma properties.

Financing activities

Net cash provided by financing activities in 2013 primarily relates to borrowings from our revolving credit facility agreement (see Note 6 of Notes to Consolidated Financial Statements) made to partially fund capital expenditures for the first and second quarters of 2013. The use of cash in 2012 primarily relates to changes in our cash overdrafts.

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, 2013 or at December 31, 2012.

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 2013.

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.

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 market forward prices, while correlations and volatilities are derived from historical forward prices. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs.

We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of \$1 million at both June 30, 2013 and December 31, 2012. The value at risk for contracts held for trading purposes was less than \$1 million at both June 30, 2013 and December 31, 2012.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of \$36 million at June 30, 2013 and a net asset of \$39 million at December 31, 2012.

The value at risk for derivative contracts held for nontrading purposes was \$13 million at June 30, 2013, and \$6 million at December 31, 2012. During the last 12 months, our value at risk for these contracts ranged from a high of \$27 million to a low of \$6 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 controls 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.

Second-Quarter 2013 Changes in Internal Controls

There have been no changes during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

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

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2012, 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, 2013.

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.

35

EXHIBITS

Exhibit No.	Description
2.1	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
3.2	Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.4	Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.5	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)
10.6#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)

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10.7 Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012) (1)

10.8 Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012) (1)

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.

36

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Exhibit No.	Description
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on May 29, 2013) (1)
10.11	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.'s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) (1)
10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.14	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.14 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.15	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.16	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.17	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
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

* Filed herewith

** Furnished herewith

(1) Management contract or compensatory plan or arrangement

37

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/ J. KEVIN VANN
J. Kevin Vann
Controller (Principal Accounting Officer)

Date: August 1, 2013