WPX ENERGY, INC.
Form 10-Q
August 03, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from to

Commission file number 1-35322

WPX Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

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

855-979-2012

(Registrant s Telephone Number, Including Area Code)

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

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

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

None

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	þ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

The number of shares outstanding of the registrant s common stock at July 31, 2012 were 199,036,609.

Table of Contents

WPX ENERGY, INC.

Index

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

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, seeks, could, may, should, continues, estimates, expects, forecasts, inte objectives, targets, planned, potential, projects, scheduled, will or other similar expressions. These forward-looking statements are bas management s beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Financial condition and liquidity;

Business strategy;

Estimates of proved gas and oil reserves;

Reserve potential;

Development drilling potential;

Cash flow from operations or results of operations;

Seasonality of our business; and

Natural gas, natural gas liquids (NGLs) and crude oil prices and demand.

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

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas and oil reserves), market demand, volatility of prices and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Acts of terrorism; and
- 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, as amended, for the year ended December 31, 2011, and Part II, Item 1A. Risk Factors of this Form 10-Q.

Table of Contents

WPX Energy, Inc.

Consolidated Balance Sheet

(Unaudited)

	June 30, 2012	December 31, 2011
	(Dollars in millions, except per-share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 427	$ 526
Accounts receivable, net of allowance of $12 at June 30, 2012 and $13 at December 31, 2011	337	509
Derivative assets	342	506
Inventories	66	73
Other	41	60
Total current assets	1,213	1,674
Investments	138	125
Properties and equipment (successful efforts method of accounting)	12,829	12,199
Less accumulated depreciation, depletion and amortization	(4,498)	(3,977)
Properties and equipment, net	8,331	8,222
Derivative assets	23	10
Other noncurrent assets	137	401
Total assets	$ 9,842	$ 10,432
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 430	$ 702
Accrued and other current liabilities	219	186
Deferred income taxes	65	116
Derivative liabilities	75	152
Total current liabilities	789	1,156
Deferred income taxes	1,503	1,556
Long-term debt	1,509	1,503
Derivative liabilities	3	7
Asset retirement obligations	296	283
Other noncurrent liabilities	111	168
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; 199.0 million shares issued at June 30, 2012 and 197.1 million shares issued at December 31, 2011)	2	2
Additional paid-in-capital	5,458	5,457
Accumulated deficit	(53)	
Accumulated other comprehensive income	136	219
Total stockholders equity	5,543	5,678
Noncontrolling interests in consolidated subsidiaries	88	81

Total equity	5,631	5,759
Total liabilities and equity	$ 9,842	$ 10,432

See accompanying notes.

Table of Contents

WPX Energy, Inc.

Consolidated Statement of Operations

(Unaudited)

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Natural gas sales	$ 312	$ 423	$ 669	$ 831
Natural gas liquid sales	78	107	171	192
Oil and condensate sales	122	83	228	135
Total product revenues	512	613	1,068	1,158
Gas management	187	337	524	745
Net gains on derivatives not designated as hedges and hedge ineffectiveness (Note 10)	71	6	85	8
Other	5	3	8	6
Total Revenues	775	959	1,685	1,917
Costs and expenses:				
Lease and facility operating	67	61	134	124
Gathering, processing and transportation	120	121	255	233
Taxes other than income	25	43	55	73
Gas management, including charges for unutilized pipeline capacity	194	344	549	761
Exploration	19	14	38	26
Depreciation, depletion and amortization	248	224	476	431
Impairment of costs of acquired unproved reserves (Note 4)	65		117	
General and administrative	71	63	139	130
Other net	(2)	4	3	5
Total costs and expenses	807	874	1,766	1,783
Operating income (loss)	(32)	85	(81)	134
Interest expense	(26)	(48)	(52)	(97)
Interest capitalized	3	4	5	8
Investment income and other	8	6	18	12
Income (loss) from continuing operations before income taxes	(47)	47	(110)	57
Provision (benefit) for income taxes	(18)	17	(43)	20
Income (loss) from continuing operations	(29)	30	(67)	37
Income (loss) from discontinued operations	23	(2)	21	(10)
Net income (loss)	(6)	28	(46)	27
Less: Net income attributable to noncontrolling interests	4	3	7	5
Net income (loss) attributable to WPX Energy	$ (10)	$ 25	$ (53)	$ 22
Amounts attributable to WPX Energy, Inc.:				

Basic and diluted earnings (loss) per common share (see Note 3):				
Income (loss) from continuing operations	$ (0.17)	$ 0.13	$ (0.37)	$ 0.16
Income (loss) from discontinued operations	0.12		0.10	(0.05)
Net income (loss)	$ (0.05)	$ 0.13	$ (0.27)	$ 0.11
Weighted-average shares (millions)	198.9	197.1	198.5	197.1

See accompanying notes.

Table of Contents

WPX Energy, Inc.

Consolidated Statement of Comprehensive Income (Loss)

(Unaudited)

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
	(Millions)			
Net income (loss) attributable to WPX Energy	$ (10)	$ 25	$ (53)	$ 22
Other comprehensive income (loss):				
Change in fair value of cash flow hedges, net of tax	$ 3	$ 49	$ 68	$ 36
Net reclassifications into earnings of net cash flow hedge gains, net of tax	(84)	(42)	(151)	(89)
Other comprehensive income (loss), net of tax	(81)	7	(83)	(53)
Comprehensive income (loss) attributable to WPX Energy	$ (91)	$ 32	$ (136)	$ (31)

See accompanying notes.

Table of Contents

WPX Energy, Inc.

Consolidated Statement of Changes in Equity

(Unaudited)

	WPX Energy, Inc., Stockholders						
	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Stockholders Equity	Noncontrolling Interests in Consolidated Subsidiaries(a)	Total Equity
				(Millions)			
Balance at December 31, 2011	$ 2	$ 5,457	$	$ 219	$ 5,678	$ 81	$ 5,759
Comprehensive income (loss):							
Net income (loss)			(53)		(53)	7	(46)
Other comprehensive loss				(83)	(83)		(83)
Comprehensive loss							(129)
Stock based compensation		1			1		1
Balance at June 30, 2012	$ 2	$ 5,458	$ (53)	$ 136	$ 5,543	$ 88	$ 5,631

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

See accompanying notes.

Table of Contents

WPX Energy, Inc.

Consolidated Statement of Cash Flows

(Unaudited)

	Six months ended June 30, 2012	2011
	(Millions)	
Operating Activities		
Net income (loss)	$ (46)	$ 27
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	483	454
Deferred income tax provision (benefit)	(56)	(17)
Provision for impairment of properties and equipment (including certain exploration expenses)	142	42
Amortization of stock-based awards	15	
(Gain) loss on sale of assets	(38)	
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	163	(21)
Inventories	7	7
Margin deposits and customer margin deposit payable	(5)	(30)
Other current assets	6	(7)
Accounts payable	(158)	63
Accrued and other current liabilities	29	15
Changes in current and noncurrent derivative assets and liabilities	(59)	13
Other, including changes in other noncurrent assets and liabilities	(42)	(23)
Net cash provided by operating activities	441	523
Investing Activities		
Capital expenditures (a)	(828)	(683)
Proceeds from sale of assets	306	
Purchases of investments	(2)	(6)
Other	5	22
Net cash used in investing activities	(519)	(667)
Financing Activities		
Proceeds from common stock	1	
Proceeds from long-term debt	6	
Net increase in notes payable to Williams		159
Net changes in Williams net investment		(3)
Revolving debt facility costs		(8)
Other	(28)	(5)
Net cash provided by (used in) financing activities	(21)	143
Net decrease in cash and cash equivalents	(99)	(1)
Cash and cash equivalents at beginning of period	526	37
Cash and cash equivalents at end of period	$ 427	$ 36
	$ (740)	$ (667)

(a) Increase to properties and equipment		
Changes in related accounts payable	(88)	(16)
Capital expenditures	$ (828)	$ (683)

See accompanying notes.

Table of Contents

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 in Exhibit 99.1 of our Form 8-K dated May 15, 2012. 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, 2012, results of operations for the three and six months ended June 30, 2012 and 2011, changes in equity for the six months ended June 30, 2012 and cash flows for the six months ended June 30, 2012 and 2011.

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, natural gas liquids and oil development and production and gas management activities located in Colorado, New Mexico, North Dakota (Bakken Shale), Pennsylvania (Marcellus Shale) 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, Green River and Appalachian Basins. Associated with our commodity production are sales and marketing activities that include the management of various commodity contracts such as transportation, storage and related derivatives coupled with the sale of our commodity volumes.

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

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

Separation from Williams

On February 16, 2011, Williams announced that its board of directors had approved pursuing a plan to separate Williams businesses into two stand-alone, publicly traded companies. As a result, WPX Energy, Inc. was formed to effect the separation. On November 30, 2011, the Board of Directors of Williams approved the spin-off of the Company. The spin-off was completed by way of a distribution on December 31, 2011.

Basis of Presentation

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

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Discontinued operations

During the second quarter of 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. Beginning in the first quarter of 2012, we reported the results of operations and financial position of the Barnett Shale operations as discontinued operations for all periods presented. The results of operations and financial position of the Arkoma operations were already reported as discontinued operations beginning in 2011 as we initiated a formal process to pursue the divestiture of those operations in the first quarter of 2011.

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

Note 2. Discontinued Operations

Summarized Results of Discontinued Operations

During the first quarter of 2012, our management signed an agreement to divest its holdings in the Barnett Shale and the Arkoma Basin for $306 million, subject to closing adjustments. The buyer provided $31 million in cash as a deposit at the signing of the agreement. During the second quarter of 2012, the transaction closed and we received an additional $270 million before closing and transaction costs. The Barnett Shale properties include approximately 27,000 net acres, interests in 320 wells and 91 miles of pipeline. The Arkoma properties include approximately 66,000 net acres, interests in 525 wells and 115 miles of pipeline.

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	(Millions)			
Revenues	$ 6	$ 33	$ 26	$ 64
Income (loss) from discontinued operations before impairments, gain on sale and income taxes	$ 1	$ (3)	$ (1)	$ (5)
Impairments				(11)
Gain on sale	35		35	
(Provision) benefit for income taxes	(13)	1	(13)	6
Income (loss) from discontinued operations	$ 23	$ (2)	$ 21	$ (10)

Impairments in 2011 reflect write-downs to estimates of fair value less costs to sell the assets of the Arkoma Basin operations that were classified as held for sale as of June 30, 2011. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, utilized a probability-weighted discounted cash flow analysis that was based on internal cash flow models.

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	(Millions, except per-share amounts)			
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$ (33)	$ 27	$ (74)	$ 32
Basic weighted-average shares	198.9	197.1	198.5	197.1
Diluted weighted-average shares	198.9	197.1	198.5	197.1
Earnings (loss) per common share from continuing operations:				
Basic	$ (0.17)	$ 0.13	$ (0.37)	$ 0.16
Diluted	$ (0.17)	$ 0.13	$ (0.37)	$ 0.16

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

For the three and six months ended June 30, 2012, 1.5 million and 2.0 million, respectively, weighted-average nonvested restricted stock units 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.

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

Note 4. Impairments and Exploration Expenses

Impairment of cost of acquired unproved reserves

As a result of continued declines in forward natural gas prices since both year-end 2011 and March 31, 2012, we performed impairment assessments of our capitalized cost of acquired unproved reserves during first and second quarter 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, respectively. Our impairment analyses included an assessment of discounted future cash flows, which considered information obtained from drilling, other activities and natural gas reserve quantities (See Note 9).

11

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Exploration Expenses

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
	(Millions)			
Geologic and geophysical costs	$ 5	$ 1	$ 12	$ 3
Dry hole costs		1	1	1
Unproved leasehold property impairment, amortization and expiration	14	12	25	22
Total exploration expense	$ 19	$ 14	$ 38	$ 26

Note 5. Inventories

	June 30, 2012	December 31, 2011
	(Millions)	
Natural gas in underground storage	$ 25	$ 34
Material, supplies and other	41	39
	$ 66	$ 73

During the first quarter of 2012, we recognized a lower of cost or market adjustment to natural gas in underground storage of approximately $11 million. This adjustment is reflected in gas management expense on the consolidated statement of operations for the six months ended June 30, 2012.

Note 6. Debt and Banking Arrangements

In November 2011, we issued $1.5 billion in face value Senior Notes. The Notes were issued under an indenture between us and The Bank of New York Mellon Trust Company, N.A., as trustee. The net proceeds from the offering of the Notes were approximately $1.481 billion after deducting the initial purchasers discounts and our offering expenses. We retained $500 million of the net proceeds from the issuance of the Notes and distributed the remainder of the net proceeds from the issuance of the Notes, approximately $981 million, to Williams.

In June 2012, we completed an exchange offer whereby we exchanged our privately-placed Notes for like principal amounts of registered 5.250% Senior Notes due 2017 and 6.000% Senior Notes due 2022. The exchange offer fulfilled our obligations under the registration rights agreement that we entered into as part of the November 2011 issuance.

During 2011, we entered into a new $1.5 billion five-year senior unsecured revolving credit facility agreement (the Credit Facility Agreement). Under the terms of the Credit Facility Agreement and subject to certain requirements, we may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. At June 30, 2012, there were no amounts outstanding under the Credit Facility Agreement.

Letters of Credit

In addition to the Notes and Credit Facility Agreement, WPX has entered into three bilateral, uncommitted letter of credit (LC) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility Agreement. At June 30, 2012, a total of $269 million in letters of credit have been issued.

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Other

Apco has a loan agreement with a financial institution for a $10 million bank line of credit. The funds could be borrowed during a one year period which ended March 2012. As of June 30, 2012, Apco has borrowed $8 million under this banking agreement. Principal amounts will be repaid in installments through 2016. This debt agreement contains covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, purchase or sell assets outside the ordinary course of business and incur additional debt.

Note 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,	
	2012	2011	2012	2011
	(Millions)			
Current:				
Federal	$ 9	$ 25	$ 19	$ 31
State		2		3
Foreign	5	3	8	5
	14	30	27	39
Deferred:				
Federal	(31)	(12)	(66)	(17)
State	(1)	(1)	(4)	(2)
Foreign				
	(32)	(13)	(70)	(19)
Total provision (benefit)	$ (18)	$ 17	$ (43)	$ 20

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 spin-off.

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 provision for the six months ended June 30, 2011, approximates the federal statutory rate as the taxes on foreign operations partially offset the effect of state income taxes.

The effective income tax rate of the total provision for the three months ended June 30, 2011, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations.

As of June 30, 2012, the amount of unrecognized tax benefits is insignificant. During the next 12 months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter will result in a significant increase or decrease of our unrecognized tax benefit.

Note 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 resulting from calculation errors. We entered into a final, partial settlement agreement. The partial settlement

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims.

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint alleges failure to pay royalty on hydrocarbons including drip condensate, fraud and misstatement of 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. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states though such guidelines are expected in the future. However, the timing of any such guidance is uncertain. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From July 2005 through June 2012, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $96 million.

The New Mexico State Land Office Commissioner has filed suit against us in Santa Fe County alleging that we have underpaid royalties due per the oil and gas leases with the State of New Mexico. In August 2011, the parties agreed to stay this matter pending the New Mexico Supreme Court s resolution of a similar matter involving a different producer. At this time, we do not have a sufficient basis to calculate an estimated range of exposure related to this claim.

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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, one hour nitrogen dioxide emission limits, and hydraulic fracturing and water standards. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matters related to Williams former power business

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

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the 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 are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California energy crisis. With respect to these matters, amounts accrued are not material to our financial position.

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

Reporting of natural gas-related information to trade publications

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

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. The plaintiffs have appealed to the United States Court of Appeals for the Ninth Circuit. Because of the

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

Other Indemnifications

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

At June 30, 2012, 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, 2012 and December 31, 2011, the Company had accrued approximately $18 million and $23 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.

	June 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$ 25	$ 334	$ 6	$ 365	$ 55	$ 454	$ 7	$ 516
Energy derivative liabilities	$ 16	$ 56	$ 6	$ 78	$ 41	$ 112	$ 6	$ 159

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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.

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

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

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

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

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the net fair value of our derivatives portfolio expiring in the next 18 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at June 30, 2012, 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 transfers between Level 1 and Level 2 occurred during the periods ended June 30, 2012 and 2011. During the period ended June 30, 2011, certain NGL swaps that originated during the first quarter of 2011 were transferred from Level 3 to Level 2. Prior to March 31, 2011, these swaps were considered Level 3 due to a lack of observable third-party market quotes. Due to an increase in exchange-traded transactions and greater visibility from OTC trading, we transferred these instruments to Level 2.

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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,		Six months ended June 30,	
	2012	2011	2012	2011
	(Millions)			
Beginning balance	$ (1)	$ 1	$ 1	$ 1
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	2	3	3	8
Settlements	(1)	(3)	(4)	(5)
Transfers out of Level 3				(3)
Ending balance	$	$ 1	$	$ 1
Unrealized gains included in income (loss) from continuing operations relating to instruments still held at June 30	$ 1	$	$	$

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

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,	
	2012	2011
	(Millions)	
Impairments:		
Costs of acquired unproved reserves (see Note 4)	$ 117(a)	$

(a) Due to significant declines in forward natural gas and natural gas liquids prices, 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.

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

Note 10. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

We use the following methods and assumptions for financial instruments that require fair value disclosure.

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

Other: Includes margin deposits and customer margin deposits payable for which the amounts reported in the Consolidated Balance Sheet approximate fair value given the short-term status of the instruments.

Long-term debt: The fair value of our debt is determined on market rates and the prices of similar securities with similar terms and credit ratings.

Energy derivatives: Energy derivatives include futures, forwards, swaps, options and swaptions. These are carried at fair value in the Consolidated Balance Sheet. See Note 9 for a discussion of valuation of energy derivatives.

Carrying amounts and fair values of our financial instruments were as follows:

	June 30, 2012		December 31, 2011	
Asset (Liability)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(Millions)		
Cash and cash equivalents	$ 427	$ 427	$ 526	$ 526
Restricted cash (current and noncurrent)	29	29	29	29
Other	(2)	(2)	(7)	(7)
Long-term debt (a)	1,508	1,510	1,502	1,523
Net energy derivatives:				
Energy commodity cash flow hedges	218	218	347	347
Other energy derivatives	69	69	10	10

(a) Excludes capital leases.

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, natural gas liquids and crude oil attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We produce, buy and sell natural gas, natural gas liquids and crude oil 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, natural gas liquids and crude oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our natural gas producing basins. Those agreements and contracts designated as cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are purchased options, a combination of options that comprise a net purchased option or a zero-cost collar or swaptions. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings.

The following table sets forth the derivative volumes designated as hedges of production volumes as of June 30, 2012:

Commodity	Period	Contract Type	Location	Notional Volume (BBtu/day)	Weighted Average Price ($/MMBtu)
Natural Gas	Jul Dec 2012	Location Swaps	Rockies	135	$ 4.76
Natural Gas	Jul Dec 2012	Location Swaps	San Juan	110	$ 4.94
Natural Gas	Jul Dec 2012	Location Swaps	MidCon	65	$ 4.74
Natural Gas	Jul Dec 2012	Location Swaps	SoCal	33	$ 5.14
Natural Gas	Jul Dec 2012	Location Swaps	Northeast	142	$ 5.56
Natural Gas	2013	Location Swaps	Northeast	5	$ 6.48

Commodity	Period	Contract Type	Location	Notional Volume (Bbls/day)	Weighted Average Price ($/Bbl)
Crude Oil	Jul Dec 2012	Business Day Avg Swaps	WTI	8,079	$ 97.90

The following table sets forth the derivative volumes not designated as hedges of production volumes as of June 30, 2012:

Commodity	Period	Contract Type	Location	Notional Volume (BBtu/day)	Weighted Average Price ($/MMBtu)
Natural Gas	Jul Dec 2012	Location Swaps	MidCon	23	$ 4.80

Commodity	Period	Contract Type	Location	Notional Volume (Bbls/day)	Weighted Average Price ($/Bbl)
Crude Oil	Jul Dec 2012	Costless Collar	WTI	2,000	$ 85.00/$106.30
Crude Oil	2013	Business Day Avg Swaps	WTI	9,000	$ 100.52
Crude Oil	2013	Swaption	WTI	2,250	$ 108.10

Commodity	Period	Contract Type	Location	Notional Volume (Bbls/day)	Weighted Average Price ($Bbl)
Natural Gas Liquids	Jul Dec 2012	Swaps	Mont Belvieu	4,000	$ 50.74

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements and financial option contracts to mitigate the price risk associated with these contracts. Derivatives for transportation and storage contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and

20

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

providing services to third parties and affiliated entities. These legacy natural gas contracts include substantially offsetting positions and have had an insignificant net impact on earnings.

The following table depicts the notional amounts of the net long (short) positions which do not represent hedges of our production in our commodity derivatives portfolio as of June 30, 2012. Natural gas is presented in millions of British Thermal Units (MMBtu). All of the Central hub risk realizes by March 31, 2013 and 100% of the basis risk realizes by October 2015. The net index position includes contracts for the future sale of physical natural gas related to our production. These contracts result in minimal commodity price risk exposure and have a value of less than $1 million at June 30, 2012.

Derivative Notional Volumes	Unit of Measure	Central Hub Risk (a)	Basis Risk (b)	Index Risk (c)
Not Designated as Hedging Instruments				
Risk Management	MMBtu	(11,535,000)	(6,427,811)	(64,467,093)
Other	MMBtu	(2,500)	3,020,000	

(a) Includes physical and financial derivative transactions that settle against the Henry Hub price.
(b) Includes physical and financial derivative transactions priced off the difference in value between the Central Hub and another specific delivery point.
(c) Includes physical derivative transactions at an unknown future price.

Fair values and gains (losses)

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

	June 30, 2012		December 31, 2011	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 221	$ 3	$ 360	$ 13
Not designated as hedging instruments:				
Economic hedges of production	63	2	3	7
Legacy natural gas contracts from former power business	52	52	93	92
All other	29	21	60	47
Total derivatives not designated as hedging instruments	144	75	156	146
Total derivatives	$ 365	$ 78	$ 516	$ 159

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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

	Three months ended June 30,		Six months ended June 30,		
	2012	2011	2012	2011	Classification
	(Millions)		(Millions)		
Net gain recognized in other comprehensive income (loss) (effective portion)	$ 5	$ 78	$ 107	$ 58	AOCI
Net gain reclassified from *accumulated other comprehensive income* into income (effective portion) (a)	$ 132	$ 67	$ 238	$ 142	Revenues
Gain recognized in income (ineffective portion)	$ 1	$ 1	$	$	Revenues

(a) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains associated with our production 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,	
	2012	2011	2012	2011
	(Millions)		(Millions)	
Unrealized gain (loss)	$ 60	$ 3	$ 59	$ (15)
Realized gain (loss)	$ 11	$ 3	$ 26	$ 23
Net gain	$ 71	$ 6	$ 85	$ 8

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

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, 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, 2012, we had a net derivative liability position of $20 million, which includes a liability credit reserve for our own nonperformance risk of less than $1 million. The 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 were triggered, was $11 million.

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

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 mark to market gains and losses and hedge ineffectiveness on the consolidated statement of operations for the six months ended June 30, 2012, as are second quarter 2012 changes in forward mark to market value. As of June 30, 2012, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to twelve months. Based on recorded values at June 30, 2012, $138 million of net gains (net of income tax provision of $80 million) will be reclassified into earnings within the next nine months. These recorded values are based on market prices of the commodities as of June 30, 2012. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Concentration of Credit Risk

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 2012 and 2011 we did not incur any significant losses due to counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of June 30, 2012, is summarized as follows.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities and integrated oil and gas companies	$ 2	$ 2
Energy marketers and traders	2	30
Financial institutions	333	333
	$ 337	365
Credit reserves		
Gross credit exposure from derivatives		$ 365

(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.

Table of Contents

WPX Energy, Inc.

Notes to Consolidated Financial Statements (continued)

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of June 30, 2012, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders	1	3
Financial institutions	302	302
	$ 305	307
Credit reserves		
Net credit exposure from derivatives		$ 307

(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 ten largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our new marginless hedging agreements with key banks, we nor the participating financial institutions are required to provide collateral support related to hedging activities.

At June 30, 2012, we held collateral support of $7 million, 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.

Table of Contents

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

Three months ended June 30, 2012	**Domestic**	**International**	**Total**
		(Millions)	
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	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)

Three months ended June 30, 2011			
Total revenues	$ 933	$ 26	$ 959
Costs and expenses:			
Lease and facility operating	$ 55	$ 6	$ 61
Gathering, processing and transportation	121		121
Taxes other than income	37	6	43
Gas management, including charges for unutilized pipeline capacity	344		344
Exploration	13	1	14
Depreciation, depletion and amortization	219	5	224
General and administrative	61	2	63
Other net	4		4
Total costs and expenses	$ 854	$ 20	$ 874
Operating income	$ 79	$ 6	$ 85
Interest expense	(48)		(48)
Interest capitalized	4		4
Investment income and other	2	4	6
Income (loss) from continuing operations before income taxes	$ 37	$ 10	$ 47

Table of Contents

Six months ended June 30, 2012	Domestic	International (Millions)	Total
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	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)

Six months ended June 30, 2011			
Total revenues	$ 1,867	$ 50	$ 1,917
Costs and expenses:			
Lease and facility operating	$ 113	$ 11	$ 124
Gathering, processing and transportation	233		233
Taxes other than income	64	9	73
Gas management, including charges for unutilized pipeline capacity	761		761
Exploration	24	2	26
Depreciation, depletion and amortization	421	10	431
General and administrative	125	5	130
Other net	4	1	5
Total costs and expenses	$ 1,745	$ 38	$ 1,783
Operating income	$ 122	$ 12	$ 134
Interest expense	(97)		(97)
Interest capitalized	8		8
Investment income and other	3	9	12
Income (loss) from continuing operations before income taxes	$ 36	$ 21	$ 57
Total assets			
Total assets as of June 30, 2012	$ 9,515	$ 327	$ 9,842
Total assets as of December 31, 2011	$ 10,144	$ 288	$ 10,432

Table of Contents

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. 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, particularly in Risk Factors and Forward-Looking Statements.

Overview

The following table presents our production volumes and financial highlights for the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Production Sales Data: (a)				
Domestic natural gas (MMcf)	102,163	95,207	203,509	187,680
Domestic NGLs (MBbls)	2,779	2,527	5,525	4,952
Domestic oil (MBbls)	1,123	714	2,071	1,098
Domestic combined equivalent volumes (MMcfe) (b)	125,574	114,655	249,084	223,986
Domestic per day combined equivalent volumes (MMcfe/d)	1,380	1,260	1,369	1,237
Domestic combined equivalent volumes (MBoe)	20,929	19,109	41,514	37,331
International combined equivalent volumes (MMcfe) (b)(c)	5,362	5,280	10,414	10,206
Financial Data (millions):				
Total domestic revenues	$ 741	$ 933	$ 1,620	$ 1,867
Total international revenues	$ 34	$ 26	$ 65	$ 50
Consolidated operating income (loss)	$ (32)	$ 85	$ (81)	$ 134
Consolidated capital expenditures	$ 400	$ 364	$ 828	$ 683

(a) Excludes production from our Arkoma Basin and Barnett Shale operations which are classified as discontinued operations and comprise less than 6 percent of our total production.

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

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

Our 2012 results continue to be impacted by lower realized natural gas prices coupled with lower natural gas liquids prices relative to the first six months of 2011. Also, as a result of continued declines in forward natural gas prices from March 31, 2012 and December 31, 2011, we recorded total impairments of costs of acquired unproved reserves primarily in the Powder River Basin of approximately $65 million in second quarter and $117 million in total for the six months ended June 30, 2012. Further declines in the forward commodity prices would result in additional impairments of the costs of acquired unproved reserves. Additional factors could also trigger impairments of our costs of acquired unproved reserves and include changes to estimates of reserve quantities, drilling plans, and expected capital and operating costs. Partially offsetting the impact of these declining natural gas and natural gas liquids prices and impairments, is the increase in our overall production volumes. We expect the oil, natural gas liquids and natural gas production increases to continue period-over-period throughout 2012.

As noted in our Form 10-K with regards to potential impairment of our producing assets, we estimated that approximately eight percent could be at risk for impairment if forward prices across all future periods declined

Table of Contents

by approximately 12 percent to 15 percent, on average, as compared to the forward prices at December 31, 2011. A substantial portion of the remaining carrying value of these other assets could be at risk for impairment if forward prices across all future periods decline by at least 24 percent, on average, as compared to the prices at December 31, 2011. Through June 30, 2012, forward natural gas prices have continued to decline from December 31, 2011 and averaged 13 percent over all periods with a decline greater than 15 percent in 2012. Additionally, we observed declines in the forward prices as of June 30, 2012 for natural gas liquids and crude oil as compared to December 31, 2011. Because of the decline in the forward prices, we performed a review in the second quarter of a portion of our producing properties which we noted to be at risk if prices were to drop by 12 to 15 percent, on average, as compared to forward prices at December 31, 2011. While the review of the properties did not result in an impairment charge of our producing properties, we estimate that a marginal decline in the forward prices as of June 30, 2012 could result in impairment charges on approximately one percent of our producing assets and a price decline of six percent could result in impairment charges on approximately four percent of our producing properties. If forward prices, including crude oil, were to decline an additional 12 to 17 percent on average across all periods, approximately 89 percent of our producing assets would need to be assessed for impairment. Our total net book value of our producing assets are approximately $6.6 billion as of June 30, 2012. Additional factors could also trigger impairments of our producing properties and include changes to estimates of proved reserves quantities, drilling plans, and expected capital and operating costs.

Outlook

For the remainder of 2012, we anticipate continued weakness in NGL realizations and a low natural gas price. A significant portion of our natural gas and oil volumes are hedged at attractive prices and we are well positioned to continue to execute on our business strategy of finding and developing reserves and producing natural gas, NGLs and oil at costs that generate an attractive return on our consolidated incremental development investments. We will continue to develop a more balanced reserve and production portfolio that includes a larger portion of oil and NGLs.

We believe that our portfolio of reserves provides us an opportunity to continue to grow our oil production, primarily in the Williston Basin. At current natural gas and NGL prices, we will continue to focus our drilling efforts first on the Piceance Basin and its higher concentration of NGLs and then the Marcellus Shale. The Piceance Basin remains an area with attractive incremental returns with our large-scale position and ability to extract liquids. In the Marcellus Shale we will focus our efforts on developing and drilling primarily in the Susquehana county of Pennsylvania, our highest returning area in Appalachia with a strategic drilling plan focused on managing leasehold expirations. We will also focus on evaluating and acquiring new undeveloped acreage in areas we believe may have significant resource potential. We anticipate our capital spending in 2012 will be approximately $1.4 billion.

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

- Continuing to invest in and grow our production and reserves;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position in the Williston Basin and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- 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;

Unavailability of capital;

Table of Contents

Counterparty credit and performance risk;

Decreased drilling success;

General economic, financial markets or industry downturn;

Changes in the political and regulatory environments; and

Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation.

We anticipate some recovery on natural gas prices in 2013. Should this expected recovery not occur, we would need to either significantly reduce our capital spending or utilize 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.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we began entering into commodity derivative contracts that 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 June 30, 2012 that are included in accumulated other comprehensive income have been and will continue to be transferred to earnings during the same periods in which the forecasted hedged transactions are recognized.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. For the remainder of 2012 we have the following contracts as of June 30, 2012 for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Jul Dec 2012 Natural Gas	
		Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Location swaps	Rockies	135	$4.76
Location swaps	San Juan	110	$4.94
Location swaps	Mid-Continent	88	$4.76
Location swaps	Southern California	33	$5.14
Location swaps	Northeast	142	$5.56

	Jul Dec 2012 Crude Oil	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl) Floor-Ceiling for Collars
WTI crude oil fixed-price	8,079	$97.90
WTI crude oil costless collar	2,000	$85.00 $106.30

Jul Dec 2012 Natural Gas Liquids

	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Natural Gas Liquid Swaps	4,000	$50.74

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

Table of Contents

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

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

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended June 30,			Percentage
	2012	2011	$ Change	Increase (Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$ 307	$ 419	$ (112)	(27)%
Natural gas liquid sales	77	106	(29)	(27)%
Oil and condensate sales	95	63	32	51%
Total product revenues	479	588	(109)	(19)%
Gas management	187	337	(150)	(45)%
Net gains on derivatives not designated as hedges and hedge ineffectiveness	71	6	65	NM
Other	4	2	2	100%
Total domestic revenues	$ 741	$ 933	$ (192)	(21)%
Total international revenues	$ 34	$ 26	$ 8	31%
Total revenues	$ 775	$ 959	$ (184)	(19)%

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

Domestic Revenues

Significant variances in comparative revenues reflect:

$112 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $3.01 for the three months ended June 30, 2012 compared to $4.41 for the three months ended June 30, 2011 on production sales volumes of 102,163 MMcf and 95,207 MMcf for the three months ended June 30, 2012 and 2011, respectively. Without hedges, our natural gas price per Mcf was $1.74 compared to $3.70 for the three months ended June 30, 2012 and 2011, respectively.

Table of Contents

$29 million decrease in natural gas liquids sales reflects a per barrel price of $27.96 compared to $41.90 for the three months ended June 30, 2012 and 2011, respectively. The decrease in sales due to low prices was partially offset by increased production sales volumes of 2,779 Mbbls and 2,527 Mbbls for the three months ended June 30, 2012 and 2011, respectively.

$32 million increase in oil and condensate sales reflects increased production sales volumes of 1,123 Mbbls compared to 714 Mbbls despite lower price per barrel of $83.89 (including the impact of hedges) compared to $87.51 for the three months ended June 30, 2012 and 2011, respectively.

$150 million decrease in gas management revenues primarily due to a 43 percent decrease in average prices on physical natural gas sales as well as 2 percent lower natural gas sales volumes. We experienced a similar decrease of $150 million in related gas management costs and expenses.

$65 million increase in net gains on derivatives not designated as hedges and hedge ineffectiveness primarily relates to unrealized mark-to-market gains on crude oil derivatives not designated as hedges.

International Revenues

International revenues increased primarily due to increased oil sales due to higher average oil sales prices and increased oil production in Argentina for the three months ended June 30, 2012 compared to the same period in 2011.

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

	Three months ended June 30, 2012	2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$ 60	$ 55	$ 5	9%
Gathering, processing and transportation	120	121	(1)	(1)%
Taxes other than income	18	37	(19)	(51)%
Gas management, including charges for unutilized pipeline capacity	194	344	(150)	(44)%
Exploration	16	13	3	23%
Depreciation, depletion and amortization	242	219	23	11%
Impairment of costs of acquired unproved reserves	65		65	NM
General and administrative	68	61	7	11%
Other net		4	(4)	NM
Total domestic costs and expenses	$ 783	$ 854	$ (71)	(8)%
International costs and expenses:				
Lease and facility operating	$ 7	$ 6	$ 1	17%
Taxes other than income	7	6	1	17%
Exploration	3	1	2	NM
Depreciation, depletion and amortization	6	5	1	20%
General and administrative	3	2	1	50%
Other net	(2)		(2)	NM
Total international costs and expenses	$ 24	$ 20	$ 4	20%
Total costs and expenses	$ 807	$ 874	$ (67)	(8)%

Domestic operating income (loss)	$ (42)	$ 79	$ (121)	NM
International operating income	$ 10	$ 6	$ 4	67%

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

Table of Contents

Domestic Costs

Significant variances in comparative costs and expenses reflect:

- Lease and facility operating expense averaged $0.47 per Mcfe compared to $0.48 per Mcfe for the three months ended June 30, 2012 and 2011, respectively.

- Gathering, processing and transportation charges averaged $0.95 per Mcfe compared to $1.06 per Mcfe for the three months ended June 30, 2012 and 2011, respectively.

- $19 million decrease in taxes other than income for the three months ended June 30, 2012 primarily reflecting the impact of decreased total product revenues (excluding hedges) resulting from lower commodity prices in 2012 compared to 2011. Taxes other than income averaged $0.15 per Mcfe for the second quarter 2012 compared to $0.33 per Mcfe for the same period in 2011.

- $150 million decrease in gas management expenses, primarily due to a 45 percent decrease in average prices on physical natural gas cost of sales as well as a 2 percent decrease in natural gas sales volumes. Also included in gas management expenses are $12 million and $8 million for the three months ended June 30, 2012 and 2011, respectively, for unutilized pipeline capacity.

- $23 million higher depreciation, depletion and amortization expenses reflect higher production volumes. During the three months ended June 30, 2012, our depreciation, depletion and amortization averaged $1.93 per Mcfe compared to an average $1.92 per Mcfe for the same period in 2011. During second quarter 2012, we adjusted our estimated proved reserves used for the calculation of depletion and amortization to reflect the impact of the decrease in the 12 month average price as of June 30, 2012. This resulted in $8 million of additional depreciation, depletion and amortization expense for second quarter 2012.

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

- $7 million increase in general and administrative expense primarily relates to increased compensation expense (including stock based compensation), increased expenses related to the transition costs after the spin-off and higher outside service expenses for the three months ended June 30, 2012 compared to the same period in 2011. General and administrative expense averaged $0.54 per Mcfe compared to $0.53 per Mcfe for the three months ended June 30, 2012 and 2011, respectively.

International costs

International costs increased primarily due to increased exploration expenses related to 3-D seismic acquisition costs.

Consolidated results below operating income (loss)

	Three months ended June 30,		$ Change	Percentage Increase (Decrease)
	2012	2011		
	(Millions)			

Consolidated operating income (loss)	$ (32)	$ 85	$ (117)	NM
Interest expense	(26)	(48)	22	(46)%
Interest capitalized	3	4	(1)	(25)%
Investment income and other	8	6	2	33%
Income (loss) from continuing operations before income taxes	(47)	47	(94)	NM
Provision (benefit) for income taxes	(18)	17	(35)	NM
Income (loss) from continuing operations	(29)	30	(59)	NM
Income (loss) from discontinued operations	23	(2)	25	NM
Net income (loss)	(6)	28	(34)	NM
Less: Net income attributable to noncontrolling interests	4	3	1	33%
Net income (loss) attributable to WPX Energy	$ (10)	$ 25	$ (35)	NM

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

Table of Contents

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

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

Provision (benefit) for income taxes changed favorably due to the pre-tax loss in 2012 compared to the pre-tax income in 2011. See Note 7 for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income from discontinued operations in 2012 includes a $35 million gain on the sale of our Barnett Shale and Arkoma Basin properties. See Note 2 for further discussion.

Six Month-Over-Six Month Results of Operations

Revenue Analysis

	Six months ended June 30,			Percentage Increase
	2012	2011	$ Change	(Decrease)
	(Millions)			
Domestic revenues:				
Natural gas sales	$ 660	$ 823	$ (163)	(20)%
Natural gas liquid sales	169	190	(21)	(11)%
Oil and condensate sales	175	97	78	80%
Total product revenues	1,004	1,110	(106)	(10)%
Gas management	524	745	(221)	(30)%
Net gains on derivatives not designated as hedges and hedge ineffectiveness	85	8	77	NM
Other	7	4	3	75%
Total domestic revenues	$ 1,620	$ 1,867	$ (247)	(13)%
Total international revenues	$ 65	$ 50	$ 15	30%
Total revenues	$ 1,685	$ 1,917	$ (232)	(12)%

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

Domestic Revenues

Significant variances in comparative revenues reflect:

$163 million decrease in natural gas sales reflects a per Mcf price (including the impact of hedges) of $3.25 for the six months ended June 30, 2012 compared to $4.39 for the six months ended June 30, 2011 on production sales volumes of 203,509 MMcf and 187,680 MMcf for the six months ended June 30, 2012 and 2011, respectively. Without hedges, our natural gas price per Mcf was

$2.07 compared to $3.62 for the six months ended June 30, 2012 and 2011, respectively.

$21 million decrease in natural gas liquids sales reflects a per barrel price of $30.69 compared to $38.44 for the six months ended June 30, 2012 and 2011, respectively. The decrease in sales due to low prices was partially offset by increased production sales volumes of 5,525 Mbbls and 4,952 Mbbls for the six months ended June 30, 2012 and 2011, respectively.

$78 million increase in oil and condensate sales reflects increased production sales volumes of 2,071 Mbbls compared to 1,098 Mbbls despite lower price per barrel of $84.19 (including the impact of hedges) compared to $87.38 for the six months ended June 30, 2012 and 2011, respectively.

$221 million decrease in gas management revenues primarily due to a 38 percent decrease in average prices on physical natural gas sales partially offset by 13 percent higher natural gas sales volumes. We experienced a similar decrease of $212 million in related gas management costs and expenses.

$77 million increase in net gains on derivatives not designated as hedges and hedge ineffectiveness. Items in 2012 included $15 million of gains that 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 properties and $57 million of unrealized mark to market gains on crude oil and natural gas liquids derivatives not designated as hedges.

International Revenues

International revenues increased primarily due to increased oil sales due to higher average oil sales prices for the six months ended June 30, 2012 compared to the same period in 2011.

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

	Six months ended June 30, 2012	Six months ended June 30, 2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$ 121	$ 113	$ 8	7%
Gathering, processing and transportation	255	233	22	9%
Taxes other than income	43	64	(21)	(33)%
Gas management, including charges for unutilized pipeline capacity	549	761	(212)	(28)%
Exploration	30	24	6	25%
Depreciation, depletion and amortization	464	421	43	10%
Impairment of costs of acquired unproved reserves	117		117	NM
General and administrative	133	125	8	6%
Other net	5	4	1	25%
Total domestic costs and expenses	$ 1,717	$ 1,745	$ (28)	(2)%
International costs and expenses:				
Lease and facility operating	$ 13	$ 11	$ 2	18%
Taxes other than income	12	9	3	33%
Exploration	8	2	6	NM
Depreciation, depletion and amortization	12	10	2	20%
General and administrative	6	5	1	20%
Other net	(2)	1	(3)	NM
Total international costs and expenses	$ 49	$ 38	$ 11	29%
Total costs and expenses	$ 1,766	$ 1,783	$ (17)	(1)%
Domestic operating income (loss)	$ (97)	$ 122	$ (219)	NM

International operating income	$	16	$	12	$	4	33%

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

Table of Contents

Domestic Costs

Significant variances in comparative costs and expenses reflect:

- Lease and facility operating expense for the six months ended June 30, 2012 averaged $0.48 per Mcfe compared to $0.50 per Mcfe for the same period in 2011.

- $22 million increase in gathering, processing and transportation expenses primarily as a result of an increase in natural gas liquids volumes. This increase also includes a $9 million adjustment related to royalty calculations for prior periods. Excluding this adjustment our gathering, processing and transportation charges averaged $0.98 per Mcfe compared to an average of $1.04 per Mcfe for the six months ended June 30, 2012 and 2011, respectively.

- $21 million decrease in taxes other than income for 2012 primarily reflecting the impact of decreased total product revenues (excluding hedges) resulting from lower commodity prices in 2012 compared to 2011. During the six months ended June 30, 2012 our taxes other than income averaged $0.17 per Mcfe compared to an average $0.28 per Mcfe for the same period in 2011.

- $212 million decrease in gas management expenses, primarily due to a 38 percent decrease in average prices on physical natural gas cost of sales partially offset by a 13 percent increase in natural gas sales volumes. Also included in gas management expenses are $23 million and $18 million for the six months ended June 30, 2012 and 2011, 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.

- Change in exploration expenses for 2012 relates to increased geologic and geophysical costs and increased amortization of unproved leasehold costs.

- $43 million higher depreciation, depletion and amortization expenses reflect higher production volumes. During the six months ended June 30, 2012 our depreciation, depletion and amortization averaged $1.87 per Mcfe compared to an average $1.88 per Mcfe for the same period in 2011. During second quarter 2012, we adjusted our estimated proved reserves used for the calculation of depletion and amortization to reflect the impact of the decrease in the 12 month average price as of June 30, 2012. This resulted in $8 million of additional depreciation, depletion and amortization expense for second quarter 2012.

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

- $8 million increase in general and administrative expense primarily relates to increased compensation expense (including stock based compensation), increased expenses related to the transition costs after the spin-off and higher outside service expenses for the six months ended June 30, 2012 compared to the same period in 2011. General and administrative expense averaged $0.53 per Mcfe compared to $0.56 per Mcfe for the six months ended June 30, 2012 and 2011, respectively.

International costs

International costs increased primarily due to greater production and lifting costs as well as higher exploration expenses related to 3-D seismic acquisition costs.

Table of Contents

Consolidated results below operating income (loss)

	Six months ended June 30, 2012	2011	$ Change	Percentage Increase (Decrease)
	(Millions)			
Consolidated operating income (loss)	$ (81)	$ 134	$ (215)	NM
Interest expense	(52)	(97)	45	(46)%
Interest capitalized	5	8	(3)	(38)%
Investment income and other	18	12	6	50%
Income (loss) from continuing operations before income taxes	(110)	57	(167)	NM
Provision (benefit) for income taxes	(43)	20	(63)	NM
Income (loss) from continuing operations	(67)	37	(104)	NM
Income (loss) from discontinued operations	21	(10)	31	NM
Net income (loss)	(46)	27	(73)	NM
Less: Net income attributable to noncontrolling interests	7	5	2	40%
Net income (loss) attributable to WPX Energy	$ (53)	$ 22	$ (75)	NM

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

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

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

Provision (benefit) for income taxes changed favorably due to the pre-tax loss in 2012 compared to the pre-tax income in 2011. See Note 7 for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income from discontinued operations in 2012 includes a $35 million gain on the sale of our Barnett Shale and Arkoma Basin properties. See Note 2 for further discussion.

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. Despite lower realized commodity prices, we have demonstrated the financial flexibility to maintain an adequate cash balance and access to our $1.5 billion credit facility. Contributing positively to our available liquidity was the realization of approximately $301 million in proceeds from the sale of our Barnett Shale and Arkoma basin properties. Despite the expectation of sustained lower commodity prices, the sources of liquidity along with our expected cash flows from operations should be sufficient to allow us to pursue our business strategy and goals for the remainder of 2012 and 2013.

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

Our capital expenditures are estimated to be approximately $1.4 billion in 2012, and are generally considered to be largely discretionary; and

Apco s liquidity requirements will continue to be provided from its cash flows from operations.

Table of Contents

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

- Sustained reductions in energy commodity prices from the range of current expectations;
- Lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices and lower economic hedged volumes in 2013;
- Significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold;
- Higher than expected collateral obligations that may be required, including those required under new commercial agreements; 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 2012 and 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. As of June 30, 2012 we have not accessed our credit facility.

Sources (Uses) of Cash

	Six months ended June 30, 2012	2011
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 441	$ 523
Investing activities	(519)	(667)
Financing activities	(21)	143
Decrease in cash and cash equivalents	$ (99)	$ (1)

Operating activities

Our net cash provided by operating activities for the six months ended June 30, 2012 decreased from the same period in 2011 primarily due to the decrease in our operating results.

Investing activities

Significant transactions include expenditures for drilling and completion of $695 million and $609 million for the six months ended June 30, 2012 and 2011, respectively. Also included in 2012 is $31 million during the first quarter and $270 million during the second quarter in proceeds received from the sale of the Barnett and Arkoma properties. Increased spending in 2012 was largely attributable to Bakken Shale drilling and completion costs as we ramp up production in that area and the Marcellus Shale.

Financing activities

The use of cash in 2012 primarily relates to changes in our cash overdrafts. Cash provided in 2011 related to our net increase in notes payable to Williams.

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, 2012 or at December 31, 2011.

Table of Contents

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 2012.

Commodity Price Risk

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

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

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

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net asset of $1 million at June 30, 2012 and a net liability of $4 million at December 31, 2011. The value at risk for contracts held for trading purposes was less than $1 million at both June 30, 2012 and June 30, 2011.

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 $68 million and $14 million at June 30, 2012 and December 31, 2011, respectively.

Table of Contents

The value at risk for derivative contracts held for nontrading purposes was $27 million at June 30, 2012, and $15 million at December 31, 2011. During the last 12 months, our value at risk for these contracts ranged from a high of $30 million to a low of $15 million.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $218 million and $347 million as of June 30, 2012 and December 31, 2011, respectively. The decrease in value is primarily due to 2012 natural gas realizations partially offset by favorable changes due to falling prices on a net short natural gas and crude positions. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Table of Contents

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 2012 Changes in Internal Controls

In the second quarter, we completed the accounting and financial systems transition from our former parent company s environment to our own environment. The systems transitioned include our enterprise resource planning and fixed assets accounting applications. Although the systems and their functionality remained substantially unchanged from what had been implemented at our former parent, this transition affected Internal Controls.

Other than described above, there have been no changes during the second quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

Table of Contents

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, as amended, for the year ended December 31, 2011, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed, except as set forth below:

The Argentine government could take action with regard to our concessions before their contract terms expire.

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

Table of Contents

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)
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)
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)

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.

Table of Contents

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. 2011 Incentive Plan (incorporated herein by reference to Exhibit 4.3 to WPX Energy, Inc. s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011)
10.11	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)
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)
10.13	Form of 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, 2011)
10.14	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc. s Annual Report on Form 10-K for the year ended December 31, 2011)
10.15	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (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, 2011)
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

* Filed herewith
** Furnished herewith

Table of Contents

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 2, 2012