WPX ENERGY, INC.
Form 10-Q
August 02, 2018

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, 2018
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number 1-35322
WPX Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	45-1836028
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
3500 One Williams Center, Tulsa, Oklahoma	74172-0172
(Address of Principal Executive Offices)	(Zip Code)

855-979-2012
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange
6.25% Series A Mandatory Convertible Preferred Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ

The number of shares outstanding of the registrant’s common stock at August 1, 2018 were 420,013,829.

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

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

- amounts and nature of future capital expenditures;
- expansion and growth of our business and operations;
- financial condition and liquidity;
- business strategy;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- acquisitions or divestitures;
- seasonality of our business; and
- crude oil, natural gas and NGL 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 oil and natural gas reserves), market demand, volatility of commodity prices and the availability and cost of capital;
- inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- the strength and financial resources of our competitors;
- development of alternative energy sources;
- the impact of operational and development hazards;
- costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- changes in maintenance and construction costs;
- changes in the current geopolitical situation;
- our exposure to the credit risk of our customers;
- risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- risks associated with future weather conditions;
- acts of terrorism;
- other factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations"; and
- additional risks described in our filings with the Securities and Exchange Commission ("SEC").

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

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

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2017.

WPX Energy, Inc.
Consolidated Balance Sheets
(Unaudited)

	June 30, 2018	December 31, 2017
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$103	$ 189
Accounts receivable, net of allowance of $2 million as of June 30, 2018 and December 31, 2017	323	307
Derivative assets	136	36
Inventories	40	30
Assets classified as held for sale (Note 2)	—	811
Other	26	28
Total current assets	628	1,401
Investments	92	70
Properties and equipment (successful efforts method of accounting)	9,314	8,674
Less—accumulated depreciation, depletion and amortization	(2,340)	(1,983)
Properties and equipment, net	6,974	6,691
Derivative assets	49	23
Other noncurrent assets	27	22
Total assets	$7,770	$ 8,207
Liabilities and Equity		
Current liabilities:		
Accounts payable	$563	$ 446
Accrued and other current liabilities	148	209
Liabilities associated with assets held for sale (Note 2)	—	20
Derivative liabilities	363	171
Total current liabilities	1,074	846
Deferred income taxes	42	117
Long-term debt, net	2,154	2,575
Derivative liabilities	89	65
Asset retirement obligations	48	32
Other noncurrent liabilities	428	445
Contingent liabilities and commitments (Note 8)		
Equity:		
Stockholders' equity:		
Preferred stock (100 million shares authorized at $0.01 par value; 4.8 million shares outstanding at June 30, 2018 and December 31, 2017)	232	232
Common stock (2 billion shares authorized at $0.01 par value; 400.3 million and 398.3 million shares issued and outstanding at June 30, 2018 and December 31, 2017)	4	4
Additional paid-in-capital	7,483	7,479
Accumulated deficit	(3,784)	(3,588)
Total stockholders' equity	3,935	4,127
Total liabilities and equity	$7,770	$ 8,207

See accompanying notes.

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

	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Oil sales	$468	$194	$828	$353
Natural gas sales	16	16	33	33
Natural gas liquid sales	36	16	66	27
Total product revenues	520	226	927	413
Net gain (loss) on derivatives	(154)	116	(223)	319
Commodity management	64	8	100	13
Total revenues	430	350	804	745
Costs and expenses:				
Depreciation, depletion and amortization	197	141	358	254
Lease and facility operating	59	41	114	77
Gathering, processing and transportation	20	6	38	11
Taxes other than income	41	19	71	32
Exploration (Note 4)	17	16	36	52
General and administrative (including equity-based compensation of $10 million, $8 million, $17 million and $15 million for the respective periods)	44	44	87	85
Commodity management	54	8	93	13
Net gain on sales of assets (Note 4)	(1)	(7)	—	(38)
Other—net	2	7	4	11
Total costs and expenses	433	275	801	497
Operating income (loss)	(3)	75	3	248
Interest expense	(39)	(46)	(85)	(93)
Loss on extinguishment of debt	(71)	—	(71)	—
Investment income (loss) and other	1	—	—	2
Income (loss) from continuing operations before income taxes	(112)	29	(153)	157
Benefit for income taxes	(33)	(298)	(48)	(265)
Income (loss) from continuing operations	(79)	327	(105)	422
Loss from discontinued operations	(2)	(251)	(91)	(254)
Net income (loss)	(81)	76	(196)	168
Less: Dividends on preferred stock	4	4	8	8
Net income (loss) available to WPX Energy, Inc. common stockholders	$(85)	$72	$(204)	$160
Amounts available to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$(83)	$323	$(113)	$414
Loss from discontinued operations	(2)	(251)	(91)	(254)
Net income (loss)	$(85)	$72	$(204)	$160
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$(0.21)	$0.81	$(0.28)	$1.06
Loss from discontinued operations	—	(0.63)	(0.23)	(0.65)
Net income (loss)	$(0.21)	$0.18	$(0.51)	$0.41
Basic weighted-average shares	400.0	397.8	399.3	392.1
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$(0.21)	$0.77	$(0.28)	$1.01

Loss from discontinued operations	—	(0.60)	(0.23)	(0.61)
Net income (loss)	$(0.21)	$0.17	$(0.51)	$0.40
Diluted weighted-average shares	400.0	423.2	399.3	418.8

See accompanying notes.

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

	WPX Energy, Inc., Stockholders				
	Preferred Stock	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Total Stockholders' Equity
Balance at December 31, 2017	$232	$4	$ 7,479	$ (3,588)	$ 4,127
Net loss	—	—	—	(196)	(196)
Stock-based compensation, net of tax impact	—	—	12	—	12
Dividends on preferred stock	—	—	(8)	—	(8)
Balance at June 30, 2018	$232	$4	$ 7,483	$ (3,784)	$ 3,935

See accompanying notes.

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

	Six months ended June 30,	
	2018	2017
Operating Activities(a)	(Millions)	
Net income (loss)	$(196)	$168
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	365	318
Deferred income tax benefit	(75)	(24)
Provision for impairment of properties and equipment (including certain exploration expenses)	37	58
Net (gain) loss on derivatives	223	(319)
Net settlements related to derivatives	(133)	9
Amortization of stock-based awards	18	17
Loss on extinguishment of debt	71	—
Net (gain) loss on sales of assets including discontinued operations	151	(41)
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	(16)	(49)
Inventories	(11)	(3)
Other current assets	4	(5)
Accounts payable	73	72
Federal income taxes receivable	—	12
Accrued and other current liabilities	(59)	(45)
Liabilities accrued in prior years for retained transportation and gathering contracts related to discontinued operations	(28)	(29)
Other, including changes in other noncurrent assets and liabilities	4	3
Net cash provided by operating activities(a)	428	142
Investing Activities(a)		
Capital expenditures(b)	(660)	(542)
Proceeds from sales of assets	686	38
Purchase of a business	—	(798)
Purchase of investments	(23)	(3)
Net cash provided by (used in) investing activities(a)	3	(1,305)
Financing Activities		
Proceeds from common stock	5	671
Dividends paid on preferred stock	(8)	(7)
Borrowings on credit facility	303	85
Payments on credit facility	(303)	(60)
Proceeds from long-term debt, net of discount	494	—
Payments for retirement of long-term debt, including premium	(986)	—
Taxes paid for shares withheld	(12)	(10)
Payments for debt issuance costs and credit facility amendment fees	(10)	—
Other	1	(1)
Net cash provided by (used in) financing activities	(516)	678
Net decrease in cash and cash equivalents and restricted cash	(85)	(485)
Cash and cash equivalents and restricted cash at beginning of period	201	506
Cash and cash equivalents and restricted cash at end of period	$116	$21

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(a) Amounts reflect continuing and discontinued operations unless otherwise noted. See Note 2 of Notes to Consolidated Financial Statements for discussion of discontinued operations.

(b) Increase to properties and equipment	$(705)	$(596)
Changes in related accounts payable and accounts receivable	45	54
Capital expenditures	$(660)	$(542)

See accompanying notes.

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WPX Energy, Inc.
Notes to Consolidated Financial Statements
Note 1. Description of Business and Basis of Presentation
Description of Business
Operations of our company include oil, natural gas and NGL development and production primarily located in Texas, New Mexico and North Dakota. We specialize in development and production from tight-sands and shale formations in the Delaware and Williston Basins. Associated with our commodity production are sales and marketing activities, referred to as commodity management activities, that include oil and natural gas purchased from third-party working interest owners in operated wells and the management of various commodity related contracts such as transportation.
In March 2018, we sold our properties in the San Juan Basin's Gallup oil play ("San Juan Gallup") and in December 2017, we sold our natural gas-producing properties in the San Juan Basin ("San Juan Legacy"). Collectively, the San Juan Gallup and San Juan Legacy comprised our San Juan Basin operations. Subsequent to the closing of these transactions, we no longer have operations in the San Juan Basin. As a result of these divestments, the results of operations of the San Juan Basin are classified as discontinued operations on the Consolidated Statements of Operations. See Note 2 for additional information on these transactions.
In addition, we have sold other operations which are reported as discontinued operations and are discussed in Note 2 of Notes to Consolidated Financial Statements.
The consolidated businesses represented herein as WPX Energy, Inc. is also referred to as "WPX," the "Company," "we," "us" or "our."
Basis of Presentation
The accompanying interim consolidated financial statements do not include all the notes included in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto for the year ended December 31, 2017 in Exhibit 99.1 of our Form 8-K filed on May 7, 2018. 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, 2018, results of operations for the three and six months ended June 30, 2018 and 2017, changes in equity for the six months ended June 30, 2018 and cash flows for the six months ended June 30, 2018 and 2017. The Company has no elements of comprehensive income (loss) other than net income (loss).
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.
Our continuing operations comprise a single business segment, which includes the development, production and commodity management activities of oil, natural gas and NGLs in the United States.
Discontinued Operations
See Note 2 for a discussion of discontinued operations. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations.
Recently Adopted Accounting Standards
The Company adopted Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers, effective January 1, 2018 using the modified retrospective method. The core principle of the guidance in ASU 2014-09 is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The adoption of ASU 2014-09 was not material to our revenues or operating income (loss) or to our consolidated balance sheet because our performance obligations, which determine when and how revenue is recognized, are not materially changed under the new standard; thus, revenue associated with the majority of our contracts will continue to be recognized as control of products is transferred to the customer. A majority of the Company's sales contracts at June 30, 2018 have terms of less than one year. For such contracts, we have used the practical expedient in ASC 606-10-50-14 which exempts an entity from the requirement to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract with an original expected duration of one year or less. For sales contracts with terms greater than one year, we have utilized the practical expedient in ASC 606-10-50-14A, which provides that an entity is not required to disclose the transaction

price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our sales contracts for all products, each unit of production represents a separate performance obligation that is satisfied upon delivery of product to the customer, thus, future volumes to be delivered are wholly unsatisfied at the reporting period end. We incorporated any new disclosure requirements into our 2017 financial statements and footnotes included in Exhibit 99.1 of our Form 8-K filed on May 7, 2018. See Note 1 of our 2017 financial statements and footnotes included in Exhibit 99.1 in our Form 8-K filed on May 7, 2018 for additional discussion related to revenue accounting policies and disclosures. In addition, see Note 16 of our 2017 financial statements and footnotes included in Exhibit 99.1 of our Form 8-K filed on May 7, 2018 for receivables related to sales of oil, natural gas and related products and services. The composition of our receivables as of June 30, 2018 has not changed significantly as compared to December 31, 2017.

We adopted ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash, effective January 1, 2018 which requires entities to show the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows on a retrospective basis. The requirements of this standard are reflected on our Consolidated Statement of Cash Flows, including prior periods. Restricted cash was approximately $13 million and $12 million as of June 30, 2018 and December 31, 2017, respectively.

We adopted ASU 2017-01, Business Combinations, clarifying the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses effective January 1, 2018.

We adopted ASU 2017-09, Compensation - Stock Compensation (Topic 718), effective January 1, 2018. This ASU provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting in Topic 718. The adoption of this standard did not have a significant impact on our consolidated financial statements.

Accounting Standards Not Yet Adopted

In February 2016, the Financial Accounting Standards Board (“FASB”) issued ASU 2016-02, Leases, to increase transparency and comparability among organizations through recognition of right-of-use assets and lease payment liabilities on the balance sheet and disclosure of key information about leasing arrangements. Under ASU 2016-02, a determination is to be made at the inception of a contract as to whether the contract is, or contains, a lease. Leases convey the right to control the use of an identified asset in exchange for consideration. Only the lease components of a contract must be accounted for in accordance with this ASU. Non-lease components, such as activities that transfer a good or service to the customer, shall be accounted for under other applicable Topics. ASU 2016-02 permits lessees to make alternative policy elections (“practical expedients”) to not recognize right-of-use assets and lease payment liabilities for leases with terms of less than twelve months and/or to not separate lease and non-lease components and account for the non-lease components together with the lease components as a single lease component. Based on an initial review of the new guidance and the Company’s current commitments, the Company anticipates it may be required to recognize right-of-use assets and lease payment liabilities related to certain drilling rig commitments, certain equipment leases, and potentially other arrangements. We are in the process of evaluating our contracts with components that may be subject to ASU 2016-02 and have engaged a third party to assist with implementing the standard. In 2018 and 2019, we will implement appropriate changes to our business processes, systems or controls to support recognition and disclosure under the new standard. Our findings and progress toward implementation of the standard are periodically reported to management. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted for any entity in any interim or annual period. In July 2018, the FASB amended this guidance to ease the transition requirements by providing an adoption alternative that allows entities to recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption in lieu of retrospectively applying the guidance to pre-adoption periods. The Company continues to evaluate the impact of ASU 2016-02 to the Company’s Consolidated Financial Statements and related disclosures and the practical expedients we will utilize upon implementation of the standard. We do not intend to adopt the standard early.

In January 2018, the FASB issued ASU No. 2018-01, “Land Easement Practical Expedient for Transition to Topic 842,” which provides an optional practical expedient to not evaluate land easements that existed or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases under the original “Leases (Topic 840)” accounting standard (“Topic 840”). The Company enters into land easements on a routine basis as part of our ongoing operations and has many such agreements currently in place. The Company does not account for any land easements under Topic 840. As this guidance serves as an amendment to ASU 2016-02, the Company will elect this practical expedient, which becomes effective upon the date of adoption of ASU 2016-02. After the adoption of ASU 2016-02, the Company will assess any land easements entered into (or modified) on or after adoption of ASU 2016-02 to determine whether the arrangement should be accounted for as a lease.

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815). This ASU provides guidance for various components of hedge accounting including hedge ineffectiveness, the expansion of types of permissible hedging strategies, reduced complexity in the application of the long-haul method for fair value hedges and reduced complexity in assessment of effectiveness. The amendments in this Update are effective for public entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2018. Early adoption is permitted, including adoption in any interim period. The Company does not expect any significant impact on its consolidated financial statements from the adoption of this standard unless we apply hedge accounting in a future period.

Note 2. Discontinued Operations

On January 30, 2018, we signed an agreement to sell our properties in the San Juan Gallup oil play to Enduring Resources IV, LLC ("Enduring") for $700 million (subject to closing and post-closing adjustments). The transaction closed on March 28, 2018 and we received approximately $667 million (subject to post-closing adjustments). In addition, the purchaser assumed approximately $309 million of gathering and processing commitments; however, WPX has left in place a performance guarantee with respect to these commitments. We believe that any future performance under this guarantee obligation is highly unlikely given our understanding of the buyer's credit position, the indemnity arrangement between the Company and Enduring and the declining size of the obligations subject to the guarantee over time. Although we believe the probability of performance by WPX is low, we must determine the fair value of the guarantee that was provided. We estimated the fair value of the guarantee to be approximately $9 million based on the factors mentioned above along with projections of estimated future volume throughputs and risk adjusted discount rates, all of which are Level 3 inputs. This amount is included in our calculation of the loss on sale. We recorded a total loss on the sale of $147 million in 2018. The operations in the San Juan Gallup represented 12 percent of our total proved reserves at December 31, 2017 and 16 percent of our total production for 2017.

As previously noted, we sold our San Juan Legacy properties in December 2017. As a result of the dispositions of San Juan Gallup and San Juan Legacy properties, we no longer have operations in the San Juan Basin. Our discontinued operations consist of the previously owned properties in the San Juan Basin and accretion on certain transportation and gathering obligations retained and recognized in prior years related to the sale of Powder River properties.

Summarized Results of Discontinued Operations

The following table presents the results of our discontinued operations for the periods presented.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(Millions)			
Total revenues	$—	$63	$75	$129
Costs and expenses:				
Depreciation, depletion and amortization	$—	$30	$8	$64
Lease and facility operating	—	12	7	24
Gathering, processing and transportation	—	15	12	31
Taxes other than income	—	4	5	10
General and administrative	—	2	1	4
Exploration	—	5	3	8
Gain on sales of assets	—	—	—	(4)
Accretion for transportation and gathering obligations retained	1	1	3	3
Other—net	—	—	4	1
Total costs and expenses	1	69	43	141
Operating income (loss)	(1)	(6)	32	(12)
Loss on sale of assets	(1)	—	(150)	—
Loss from discontinued operations before income taxes	(2)	(6)	(118)	(12)
Income tax provision (benefit)	—	245	(27)	242
Loss from discontinued operations	$(2)	$(251)	$(91)	$(254)

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

Assets and Liabilities in the Consolidated Balance Sheets attributable to Discontinued Operations

The following table presents assets classified as held for sale and liabilities associated with assets held for sale related to our San Juan Basin operations.

	December 31, 2017
	(Millions)
Assets classified as held for sale	
Inventories	$ 14
Properties and equipment, net (successful efforts method of accounting)	797
Total assets classified as held for sale on the Consolidated Balance Sheets	$ 811
Liabilities associated with assets held for sale	
Current liabilities:	
Accounts payable	$ 1
Accrued and other current liabilities	1
Total current liabilities	2
Asset retirement obligations	15
Other noncurrent liabilities	3
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	$ 20

Cash Flows Attributable to Discontinued Operations

In addition to the amounts presented below, cash outflows related to previous accruals for the Powder River Basin gathering and transportation contracts retained by WPX were $28 million and $29 million for the six months ended June 30, 2018 and 2017, respectively.

	Six months ended June 30,	
	2018	2017
	(Millions)	
Cash provided by operating activities(a)	$ 45	$ 55
Cash capital expenditures within investing activities	$ 29	$ 77

(a) Excluding income taxes and changes in working capital items.

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

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

The following table summarizes the calculation of earnings per share.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(Millions, except per-share amounts)			
Income (loss) from continuing operations	$(79)	$327	$(105)	$422
Less: Dividends on preferred stock	4	4	8	8
Income (loss) from continuing operations available to WPX Energy, Inc. common stockholders for basic and diluted earnings (loss) per common share	$(83)	$323	$(113)	$414
Basic weighted-average shares	400.0	397.8	399.3	392.1
Effect of dilutive securities(a):				
Nonvested restricted stock units and awards	—	1.5	—	2.7
Stock options	—	0.1	—	0.2
Common shares issuable upon assumed conversion of 6.25% Series A mandatory convertible preferred stock	—	23.8	—	23.8
Diluted weighted-average shares	400.0	423.2	399.3	418.8
Earnings (loss) per common share from continuing operations:				
Basic	$(0.21)	$0.81	$(0.28)	$1.06
Diluted	$(0.21)	$0.77	$(0.28)	$1.01

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

	Three months ended June 30, 2018	Six months ended June 30, 2018
	(Millions)	
Weighted-average nonvested restricted stock units and awards	2.9	3.0
Weighted-average stock options	0.2	0.2
Common shares issuable upon assumed conversion of 6.25% Series A mandatory convertible preferred stock	19.8	19.8

The table below includes information related to stock options that were outstanding at June 30, 2018 and 2017 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,	
	2018	2017
Options excluded (millions)	0.6	1.9
Weighted-average exercise price of options excluded	$18.73	$16.68
Exercise price range of options excluded	$17.47 -	$11.75 -

	$21.81	$21.81
Second quarter weighted-average market price	$17.12	$11.40

The diluted weighted-average shares excludes the effect of approximately 0.7 million and 2.0 million nonvested restricted stock units for the six months ended June 30, 2018 and 2017, respectively. These restricted stock units were antidilutive under the treasury stock method.

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Notes to Consolidated Financial Statements — (Continued)

Note 4. Asset Sales and Exploration Expenses
Asset Sales
Net gain on sales of assets for the three and six months ended June 30, 2017 includes a gain from exchanges of leasehold acreage in the Delaware Basin, a net gain recognized on the sales of certain Green River Basin and Appalachian Basin assets and recognition of deferred gain related to the completion of commitments from the sale of a gathering system in prior years.
In conjunction with exchanges of leasehold, we estimate the fair value of the leasehold through discounted cash flow models and consideration of market data. Our estimates and assumptions include future commodity prices, projection of estimated quantities of oil and natural gas reserves, expectations for future development and operating costs and risk adjusted discount rates, all of which are Level 3 inputs.
Exploration Expenses
The following table presents a summary of exploration expenses.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(Millions)			
Unproved leasehold property impairment, amortization and expiration	$16	$ 15	$33	$ 50
Geologic and geophysical costs	1	1	3	2
Total exploration expenses	$17	$ 16	$36	$ 52

Unproved leasehold property impairment, amortization and expiration for the six months ended June 30, 2017 includes costs in excess of the accumulated amortization balance associated with certain leases in the Delaware Basin that expired during the first quarter of 2017. These leases were renewed in second-quarter 2017.
Note 5. Inventories
The following table presents a summary of our inventories as of the dates indicated below.

	June 30, 2018	December 31, 2017
	(Millions)	
Material, supplies and other	$39	$ 29
Crude oil production in transit	1	1
Total inventories	$40	$ 30

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

	June 30, 2018	December 31, 2017
	(Millions)	
Credit facility agreement	$—	$ —
7.500% Senior Notes due 2020	—	350
6.000% Senior Notes due 2022	529	1,100
8.250% Senior Notes due 2023	500	500
5.250% Senior Notes due 2024	650	650
5.750% Senior Notes due 2026	500	—
Total long-term debt	$2,179	$ 2,600
Less: Debt issuance costs on long-term debt(a)	25	25
Total long-term debt, net(a)	$2,154	$ 2,575

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(a) Debt issuance costs related to our Credit Facility are recorded in other noncurrent assets on the Consolidated Balance Sheets.

Credit Facility

As of June 30, 2018, we had no borrowings outstanding and $65 million of letters of credit issued under the Credit Facility and we were in compliance with our financial covenants with full access to the Credit Facility.

On April 17, 2018, the Company entered into a Second Amendment to Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the "Credit Facility"). The Credit Facility, as amended, increases total commitments to $1.5 billion, increases the Borrowing Base to $1.8 billion, and extends the maturity date to April 17, 2023, subject to a springing maturity on October 15, 2021 if available liquidity minus outstanding 2022 notes is less than $500 million. Based on our current credit ratings, a Collateral Trigger Period applies which makes the Credit Facility subject to certain financial covenants and a Borrowing Base as described below. The Credit Facility may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time.

Borrowing Base. During a Collateral Trigger Period, loans under the Credit Facility are subject to a Borrowing Base as calculated in accordance with the provisions of the Credit Facility. The $1.8 billion Borrowing Base will remain in effect until the next Redetermination Date as set forth in the Credit Facility and at this time, availability under the Credit Facility Agreement is limited by the total commitments of $1.5 billion. The Borrowing Base is recalculated at least every six months per the terms of the Credit Facility.

Terms and Conditions. The Credit Facility will initially be guaranteed by certain subsidiaries of the Company (excluding subsidiaries holding Midstream Assets and subsidiaries meeting other customary exclusion criteria), as Guarantors, and secured by substantially all of the Company's and the Guarantors' assets (including oil and gas properties), subject to customary exceptions and carve outs (which shall also exclude Midstream Assets and the equity interests of subsidiaries holding Midstream Assets). Such obligations shall terminate on the earlier of any applicable Collateral Trigger Termination Date (as described below) or the date on which all liens held by the Administrative Agent for the benefit of the secured parties are released pursuant to the terms of the Credit Facility.

The Collateral Trigger Termination Date is the first date following the date of the closing of the Credit Facility and the first date following any Collateral Trigger Date, as applicable, on which (i) the Company's Corporate Rating is BBB- or better by S&P (without negative outlook or negative watch) or (ii) Baa3 or better by Moody's (without negative outlook or negative watch), provided that the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody's.

Interest and Commitment Fees. Interest on borrowings under the Credit Facility is payable at rates per annum equal to, at the Company's option: (1) a fluctuating base rate equal to the alternate base rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The alternate base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. As amended and during a Collateral Trigger Period, the applicable margin ranges from 0.25% to 1.25% per annum in the case of the alternate base rate, and from 1.25% to 2.25% per annum in the case of LIBOR. The Company is required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility. As amended and during a Collateral Trigger Period, the commitment fee ranges from 0.375% to 0.500% per annum. The applicable margin and the commitment fees during a Collateral Trigger Period are determined by reference to a utilization percentage as set forth in the Credit Facility. The applicable margin and the commitment fee other than during a Collateral Trigger Period are determined by reference to the Company's senior unsecured debt ratings.

Significant Financial Covenants.

Pursuant to the amendment, the Company is required to maintain:

- a ratio of Net Indebtedness to Consolidated EBITDAX for the most recent ended four consecutive fiscal quarters (excluding the first three quarters of 2018 which will use an Annualized Consolidated EBITDAX) of not greater than 4.25 to 1.00 as of the last day of the most recently ended Rolling Period; and
- a ratio of consolidated current assets (including the unused amount of the Aggregate Commitments) of the Company and its consolidated subsidiaries to the consolidated current liabilities of the Company and its consolidated subsidiaries as of the last day of any fiscal quarter of at least 1.0 to 1.0.

If a Collateral Trigger Termination Date occurs, other financial covenants would apply and replace those listed above. See Exhibit 99.1 of our Form 8-K filed May 7, 2018 for additional information on covenants related to our Credit Facility that were unchanged under the new amendment. As of the date of this filing, we are in compliance with all terms, conditions and financial covenants of the Credit Facility, as amended.

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Notes to Consolidated Financial Statements — (Continued)

Senior Notes

In the second quarter of 2018, we used proceeds from our San Juan Gallup disposition and the issuance of new senior notes discussed below to retire $921 million aggregate principal amount of our senior notes ($350 million due 2020 and $571 million due 2022) through a series of cash tender offers. As a result of the debt tender offers, we recorded a loss on extinguishment of debt of $71 million, which includes approximately $63 million of premium and approximately $6 million write-off of previously capitalized costs.

On May 23, 2018, we completed a debt offering of $500 million of 5.750% Senior Notes due in 2026 (the "2026 Notes"). The notes are senior unsecured obligations ranking equally with the Company's other existing and future senior unsecured indebtedness. Interest is payable on the notes semiannually in arrears on June 1 and December 1 of each year commencing on December 1, 2018. The 2026 Notes will mature on June 1, 2026 with the option, prior to June 1, 2021, to redeem some or all of the notes at a specified "make whole" premium as described in the indenture governing the notes or, after June 1, 2021, we have the option to redeem the notes, in whole or in part, at the applicable redemption prices set forth in the indenture. The net proceeds from the offering of the 2026 Notes was approximately $494 million and approximately $1 million of debt issuance costs were capitalized.

See Exhibit 99.1 of our Form 8-K filed May 7, 2018, which includes the financial statements and footnotes for the year ended December 31, 2017, for additional discussion related to our senior notes.

Note 7. Provision (Benefit) for Income Taxes

The following table presents the benefit for income taxes from continuing operations.

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
	(Millions)			
Current:				
Federal	$—	$—	$—	$—
State	—	—	—	—
	—	—	—	—
Deferred:				
Federal	(28)	(18)	(37)	28
State	(5)	(280)	(11)	(293)
	(33)	(298)	(48)	(265)
Total benefit	$(33)	$(298)	$(48)	$(265)

The effective income tax rate for the three months ended June 30, 2018, differs from the new federal statutory rate of 21 percent due to the impact of equity-based compensation and the effect of state income taxes.

The effective income tax rate for the three months ended June 30, 2017, differs from the federal statutory rate of 35 percent due to the impact of equity-based compensation, the effect of state income taxes and other permanent items as applied by ASC 740 interim period allocation methodology.

The effective income tax rate for the six months ended June 30, 2018, differs from the new federal statutory rate of 21 percent due to the impact of equity-based compensation and the effect of an adjustment to state deferred taxes as a result of a decrease in the blended state income tax rate due to changes in state apportionment factors resulting from the divestment of our San Juan Basin assets.

The effective income tax rate for the six months ended June 30, 2017, differs from the federal statutory rate of 35 percent due to the impact of equity-based compensation, the effect of an adjustment to state deferred taxes as a result of a decrease in the blended state income tax rate due to changes in state apportionment factors resulting from increased presence in the Delaware Basin operations in Texas following the Panther acquisition and other permanent items as applied by ASC 740 interim period allocation methodology.

Due to the uncertainty or diversity in views about the application of ASC 740 in the period of enactment of the Tax Cuts and Jobs Act ("Act"), the SEC issued Staff Accounting Bulletin ("SAB") 118 which allowed us to provide a provisional estimate of the impacts of the Act in our results of operations for December 31, 2017. Additional impacts from the enactment of the Act will be recorded as they are identified during the one-year measurement period as provided for in SAB 118. Our estimate does not reflect the impact of potential reductions of AMT credit refunds, changes in current interpretations of performance based executive compensation deduction limitations, effects of any state tax law changes and uncertainties regarding interpretations that may arise as a result of federal tax reform. The Company will continue to analyze the effects of the Act on its financial statements and operations and record changes to our estimates as appropriate.

We have recorded valuation allowances against deferred tax assets attributable primarily to certain state net operating loss ("NOL") carryovers as well as our federal capital loss carryover. When assessing the need for a valuation allowance, we primarily consider future reversals of existing taxable temporary differences. To a lesser extent we may also consider future taxable income exclusive of reversing temporary differences and carryovers, and tax-planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by future operational performance, potential changes in jurisdictional income tax laws and other circumstances surrounding the actual realization of related tax assets. Valuation allowances that we have recorded are due to our expectation that we will not have sufficient income, or income of a sufficient character, in those jurisdictions to which the associated deferred tax asset applies. We have not recorded a valuation allowance against our federal NOL carryover, but a valuation allowance could be required in future periods if the federal NOL carryover continues to increase or circumstances change.

The ability of WPX to utilize loss carryovers or minimum tax credits to reduce future federal taxable income and income tax could be subject to limitations under the Internal Revenue Code. The utilization of such carryovers may be limited upon the occurrence of certain ownership changes during any three-year period resulting in an aggregate change of more than 50 percent in beneficial ownership (an "Ownership Change"). As of June 30, 2018, we do not believe that an Ownership Change has occurred for WPX, but an Ownership Change did occur for RKI effective with the acquisition. Therefore, there is an annual limitation on the benefit that WPX can claim from RKI carryovers that arose prior to the acquisition.

Pursuant to our tax sharing agreement with Williams, we remain responsible for the tax from audit adjustments related to our business for periods prior to our spin-off from Williams on December 31, 2011. The 2011 consolidated tax filing by Williams is currently being audited by the IRS and is the only pre-spin-off period for which we continue to have exposure to audit adjustments as part of Williams. In 2017, the IRS proposed an adjustment related to our business for which a payment to Williams could be required. We are currently evaluating the issue and expect to protest the adjustment within the normal appeals process of the IRS. In addition, the alternative minimum tax credit deferred tax asset that was allocated to us by Williams at the time of the spin-off could change due to audit adjustments unrelated to our business. Any such adjustment to this deferred tax asset will not be known until the IRS examination is completed, but is not expected to result in a cash settlement unless we have utilized any of the alternative minimum tax credits.

As of June 30, 2018, the Company has approximately $8 million of unrecognized tax benefits which is offset by an increase in deferred tax assets of approximately $7 million. Currently, we expect ultimate resolution of our uncertain tax position during the next 12 months.

Note 8. Contingent Liabilities and Commitments

Contingent Liabilities

Royalty litigation

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint presently alleges failure to pay royalty on hydrocarbons including drip condensate, breach of the duty of good faith and fair dealing, fraudulent concealment, conversion, misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons in Colorado, breach of implied duty to market, violation of the New Mexico Oil and Gas Proceeds Payment Act, and bad faith breach of contract. Plaintiffs sought monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter was removed to the United States District Court for New Mexico where the court denied plaintiffs' motion for class certification. In March 2017, plaintiffs appealed the denial of class certification to the Tenth Circuit and oral argument before the Tenth Circuit was held on January 17, 2018. In August

2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico and violation of the New Mexico Oil and Gas Proceeds Payment Act, and seek declaratory judgment, accounting and injunctive relief. On August 16, 2016, the court denied plaintiffs' motion for class certification. On September 15, 2016, plaintiffs filed their motion for reconsideration and filed a second motion for class certification, and on September 30, 2017, the Court issued its memorandum opinion and order denying the plaintiffs motion for reconsideration and their Second Motion for Class Certification. At this time, we believe that our royalty calculations have been properly determined in accordance with the

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appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we are monitoring them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue ("ONRR") in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to many of our federal leases in New Mexico. The guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. The ONRR's guidance provides its view as to how much of a producer's bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. Similar guidelines were recently issued for certain leases in Colorado and, as in the case of the New Mexico guidelines, we do not believe that they will result in a material difference to our historical federal royalty payments. ONRR has asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas.

Environmental matters

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

Matters related to Williams' former power business

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

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

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 Federal Energy Regulatory Commission exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. The plaintiffs appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion in the In re: Western States Wholesale Antitrust Litigation, holding that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims and reversing the summary judgment previously entered in favor of the defendants. The U.S. Supreme Court granted Defendants' writ of certiorari. On April 21, 2015, the U.S. Supreme Court determined that the state antitrust claims are not preempted by the federal Natural Gas Act. On March 7, 2016, the putative class plaintiffs in several of the cases filed their motions for class certification. On March 30, 2017, the court denied the motions for class certification, which decision was appealed on June 20, 2017. On May 24, 2016, in Reorganized FLI Inc. v. Williams Companies, Inc., the Court granted Defendants' Motion for Summary Judgment in its entirety, and an agreed amended judgment was entered by the court on January 4, 2017. The parties have filed numerous motions for summary judgment, reconsideration and remand, and there are currently two appeals before the Ninth Circuit. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposure at this time.

Other Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, including the agreements pursuant to which we divested our Piceance and San Juan Basin operations, 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 breaches of representations and warranties, tax liabilities, historic litigation, personal injury, environmental matters and rights-of-way. Additionally, Federal and state laws in areas of former operations may require previous operators to perform in certain circumstances where the buyer/operator may no longer be able to perform. Such duties may include plugging and abandoning wells or responsibility for surface agreements.

The indemnity provided to the purchaser of the entity that held our Piceance Basin operations relates in substantial part to liabilities arising in connection with litigation over the appropriate calculation of royalty payments. Plaintiffs in that litigation have asserted claims regarding, among other things, the method by which we took transportation costs into account when calculating royalty payments. In 2017, we settled one of these claims.

As of June 30, 2018, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss beyond any amount already accrued. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

Summary

As of June 30, 2018 and December 31, 2017, the Company had accrued approximately $11 million for loss contingencies associated with royalty litigation and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

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

Commitments

See Note 2 for a discussion of commitments that were assumed by the purchaser of our San Juan Gallup assets and a related existing performance guarantee from WPX that will remain in place.

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

Note 9. Fair Value Measurements

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

	June 30, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$ —	$ 185	$ —	$ 185	$ —	$ 59	$ —	$ 59
Energy derivative liabilities	$ —	$ 452	$ —	$ 452	$ —	$ 236	$ —	$ 236
Total debt(a)	$ —	$ 2,255	$ —	$ 2,255	$ —	$ 2,746	$ —	$ 2,746

(a) The carrying value of total debt, excluding capital leases and debt issuance costs, was $2,179 million and $2,600 million as of June 30, 2018 and December 31, 2017, respectively. The fair value of our debt, which also excludes capital leases and debt issuance costs, is determined on market rates and the prices of similar securities with similar terms and credit ratings.

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

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

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

Forward, swap, option and swaption contracts are considered Level 2 and 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 calls and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with swaps, we may sell call options or swaptions to the swap counterparties in exchange for receiving premium hedge prices on the swaps. The sold calls or swaptions establish a maximum price we will receive for the volumes under contract and are financially settled. Significant inputs into our Level 2 valuations include commodity prices, implied volatility and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of over-the-counter products or like products and the tenure of our derivatives portfolio extends through the end of 2022. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes or market indications and documented on a quarterly 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. We had instruments totaling less than $1 million included in Level 3 as of June 30, 2018.
Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers occurred during the periods ended June 30, 2018 and 2017.
There have been no material changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Note 10. Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

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

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

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Notes to Consolidated Financial Statements — (Continued)

Derivatives related to production
The following table sets forth the derivative notional volumes of the net long (short) positions that are economic hedges of production volumes, which are included in our commodity derivatives portfolio as of June 30, 2018.

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)			Weighted Average Price (c)	
Crude Oil								
Crude Oil	Jul - Dec 2018	Fixed Price Swaps	WTI	(57,500	)	$	52.82	
Crude Oil	Jul - Dec 2018	Basis Swaps	Midland-Cushing	(14,000	)	$	(0.77	)
Crude Oil	Jul - Dec 2018	Basis Swaps	Nymex CMA Roll	(16,630	)	$	0.03	
Crude Oil	Jul - Dec 2018	Basis Swaps	Argus LLS	(4,158	)	$	7.01	
Crude Oil	Jul - Dec 2018	Basis Swaps	Magellan East	(4,989	)	$	6.38	
Crude Oil	Jul - Dec 2018	Fixed Price Calls	WTI	(13,000	)	$	58.89	
Crude Oil	2019	Fixed Price Swaps	WTI	(36,000	)	$	52.86	
Crude Oil	2019	Basis Swaps	Midland-Cushing	(21,008	)	$	(1.16	)
Crude Oil	2019	Basis Swaps	Nymex CMA Roll	(20,000	)	$	0.11	
Crude Oil	2019	Fixed Price Calls	WTI	(5,000	)	$	54.08	
Crude Oil	2020	Basis Swaps	Midland-Cushing	(7,486	)	$	(1.31	)
Crude Oil	2020	Basis Swaps	Brent/WTI Spread	(3,000	)	$	8.40	
Crude Oil	2021	Basis Swaps	Brent/WTI Spread	(1,000	)	$	8.00	
Crude Oil	2022	Basis Swaps	Brent/WTI Spread	(1,000	)	$	7.75	
Natural Gas								
Natural Gas	Jul - Dec 2018	Fixed Price Swaps	Henry Hub	(130	)	$	2.99	
Natural Gas	Jul - Dec 2018	Basis Swaps	Permian	(48	)	$	(0.31	)
Natural Gas	Jul - Dec 2018	Basis Swaps	Waha	(15	)	$	0.93	
Natural Gas	Jul - Dec 2018	Basis Swaps	Houston Ship	(43	)	$	(0.08	)
Natural Gas	Jul - Dec 2018	Fixed Price Calls	Henry Hub	(16	)	$	4.75	
Natural Gas	2019	Fixed Price Swaps	Henry Hub	(50	)	$	2.87	
Natural Gas	2019	Basis Swaps	Permian	(25	)	$	(0.39	)
Natural Gas	2019	Basis Swaps	Waha	(25	)	$	1.31	
Natural Gas	2019	Basis Swaps	Houston Ship	(30	)	$	(0.09	)
Natural Gas	2020	Basis Swaps	Waha	(40	)	$	(0.79	)
Natural Gas	2021	Basis Swaps	Waha	(20	)	$	(0.57	)
Natural Gas Liquids								
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Mont Belvieu	(3,300	)	$	0.29	
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Conway Propane	(900	)	$	0.79	
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Mont Belvieu	(3,900	)	$	0.80	
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Mont Belvieu Iso	(700	)	$	0.91	
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Mont Belvieu	(1,800	)	$	0.90	
Natural Gas Liquids	Jul - Dec 2018	Fixed Price Swaps	Mont Belvieu	(1,500	)	$	1.31	

(a) Derivatives related to crude oil production are fixed price swaps settled on the business day average, basis swaps, fixed price calls or swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, fixed price calls or swaptions. In connection with swaps, we may sell call options or swaptions to the swap counterparties in exchange for receiving premium hedge prices on the swaps. The sold call or swaption establishes a maximum price we will receive for the volumes under contract and are financially settled. Basis swaps for the Nymex CMA (Calendar Monthly Average) Roll location are pricing adjustments to the trade month versus the delivery month for contract pricing. Basis swaps for the Brent/WTI location are priced off the Brent and WTI futures spread. Derivatives related to natural gas liquids production are fixed price swaps.

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

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

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

Fair values and gains (losses)

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

We enter into commodity derivative contracts that serve as economic hedges but are not designated as cash flow hedges for accounting purposes as we do not utilize this method of accounting for derivative instruments. Net gain (loss) on derivatives on the Consolidated Statements of Operations includes settlements to be paid of $78 million and $133 million for the three and six months ended June 30, 2018, respectively, and settlements received of $14 million and $9 million for the three and six months ended June 30, 2017, respectively.

The cash flow impact of our derivative activities is presented as separate line items within the operating activities on the Consolidated Statements of Cash Flows.

Offsetting of derivative assets and liabilities

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

	Gross Amount Presented on Balance Sheet	Netting Adjustments (a)	Net Amount
	(Millions)		
June 30, 2018			
Derivative assets with right of offset or master netting agreements	$185	$ (138)	$ 47
Derivative liabilities with right of offset or master netting agreements	$(452)	$ 138	$ (314)
December 31, 2017			
Derivative assets with right of offset or master netting agreements	$59	$ (42)	$ 17
Derivative liabilities with right of offset or master netting agreements	$(236)	$ 42	$ (194)

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

Credit-risk-related features

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

As of June 30, 2018, we had no collateral posted to derivative counterparties, to support the aggregate fair value of our net $314 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of $3 million to our liability balance for our own nonperformance risk. Assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, the additional collateral that we would have been required to post at June 30, 2018 was $314 million.

Concentration of Credit Risk

Cash equivalents

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

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

Accounts receivable
Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. A portion of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.
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 2018 and 2017, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.
Our gross and net credit exposure from our derivative contracts were $185 million and $47 million, respectively, as of June 30, 2018. Ninety-nine percent of our credit exposure is with investment grade financial institutions. We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum S&P's rating of BBB- or Moody's Investors Service rating of Baa3 to be investment grade.
Our three largest net counterparty positions represent approximately 100 percent of our net credit exposure. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.
One of our senior officers is on the board of directors of NGL Energy Partners, LP ("NGL Energy"). In the normal course of business, we sell crude oil to NGL Energy. For the first six months of 2018, sales to NGL Energy were approximately 12 percent of our total consolidated revenues adjusted for loss on derivatives. In addition, a subsidiary of NGL Energy provides water disposal services for WPX that represent less than 1 percent of operating expenses.
Other
Collateral support for our commodity agreements could include margin deposits, letters of credit, surety bonds and guarantees of payment by credit worthy parties.
Note 11. Subsequent Events
Based on the provisions of the mandatory convertible preferred stock offering in 2015, each share of our preferred stock would automatically convert into between 4.1254 and 4.9504 shares of our common stock (respectively, the "minimum conversion rate" and "maximum conversion rate") on July 30, 2018, subject to anti-dilution adjustments. The number of shares of our common stock issuable on conversion is determined based on the average volume weighted average price per share of our common stock (the "VWAP") over the 20 consecutive trading day period beginning on, and including, the 23rd scheduled trading day immediately preceding July 31, 2018, which is referred to as the "final averaging period." Based on the VWAP for the final averaging period, the preferred shares converted to common shares at the minimum conversion rate of 4.1254. On July 30, 2018, approximately 4.8 million shares of our preferred stock converted into approximately 19.8 million shares of our common stock pursuant to the mandatory conversion provisions of the preferred stock offering.

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 elsewhere in this Form 10-Q and Exhibit 99.1 of our Form 8-K filed on May 7, 2018. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this Form 10-Q and our 2017 Annual Report on Form 10-K.

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

Overview

Composition of production (based on MBoe) and product revenue

Three and six months ended June 30, 2018 and 2017

The following table presents our production volumes and financial highlights for the three and six months ended June 30, 2018 and 2017:

	Three months ended June 30,				Six months ended June 30,			
	2018		2017		2018		2017	
Production Sales Volume Data(a):		Per day		Per day		Per day		Per day
Oil (MBbls)	7,352	80.8	4,572	50.2	13,271	73.3	8,076	44.6
Natural gas (MMcf)	13,854	152	8,357	92	25,763	142	16,104	89
NGLs (MBbls)	1,713	18.8	959	10.5	3,053	16.9	1,665	9.2
Combined equivalent volumes (MBoe)(b)	11,374	125.0	6,923	76.1	20,618	113.9	12,424	68.6
Financial Data (millions):								
Total product revenues	$520		$226		$927		$413	
Total revenues	$430		$350		$804		$745	
Operating income (loss)	$(3)		$75		$3		$248	
Capital expenditure activity (c)	$355		$316		$705		$596	

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(a) Excludes production from discontinued operations.

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

(c) Includes capital expenditures activity related to discontinued operations of $1 million and $60 million for the three months ended June 30, 2018 and 2017, respectively, and $27 million and $103 million for the six months ended June 30, 2018 and 2017, respectively.

Our second quarter 2018 operating results were $78 million unfavorable compared to second quarter 2017. The primary items impacting the three months ended June 30, 2018 compared to the same period in 2017 include:

- $270 million unfavorable change in net gain (loss) on derivatives; and
- $110 million higher operating costs including depreciation, depletion and amortization, lease and facility, gathering, processing and transportation, and taxes other than income.

Offset by

- $294 million increase in product revenues, primarily oil sales, of which $155 million related to higher oil prices and $119 million related to higher oil volumes.

Our year-to-date 2018 operating results were $245 million unfavorable compared to year to date 2017. The primary items impacting the six months ended June 30, 2018 compared to the same period in 2017 include:

- $542 million unfavorable change in net gain (loss) on derivatives;
- $207 million higher operating costs including depreciation, depletion and amortization, lease and facility, gathering, processing and transportation, and taxes other than income; and
- the absence in 2018 of a $38 million net gain on sales of assets recorded in 2017 (see Note 4 of Notes to Consolidated Financial Statements).

Offset by

- $514 million increase in product revenues, primarily oil sales, of which $247 million related to higher oil prices and $228 million related to higher oil volumes; and
- $16 million lower exploration costs (see Note 4 of Notes to Consolidated Financial Statements).

Outlook

After our multi-year transformation of WPX, our oil-prone positions in the Delaware (Permian) and Williston Basins now form the foundation of WPX. Our acreage positions in each of these basins contains some of the top geology in the plays and in North America. We have also assembled an attractive infrastructure portfolio in the Permian which will help flow our production out of the basin and potentially create value through our midstream investments. We believe we are well positioned for prudent and disciplined growth assuming a constructive commodity price environment. Our growth plan through the end of 2018, both volumes and cash flow, is another important step in the transformation of the company in an effort to improve our leverage metrics along with other per Boe metrics. In 2019, assuming current forward pricing, we expect our operating cash flows to equal or exceed our drilling and completion capital expenditures. However, the oil and gas industry is a challenging and dynamic environment and appropriate adjustments to our plans would be made if we foresee market conditions change including significant fluctuation in commodity prices.

Our continuing operations capital budget for full year 2018 is $1.3 billion to $1.4 billion, including amounts for land and midstream opportunities. Additionally, we estimate between $70 million and $85 million for equity investments. Planned capital for drilling and completions, including non-operated wells, is $1.2 billion to $1.25 billion for the full year 2018. The plan contemplates deploying a comparable rig count compared to 2017, completing an inventory of 38 DUCs at year-end 2017, adding a third frac crew in the Delaware Basin and drilling longer laterals in the Delaware. The 2018 budget is designed to fund 7 rigs and 3 rigs in the Delaware and Williston Basins, respectively.

Our June 30, 2018 liquidity totaled approximately $1.5 billion, reflecting amounts available under the Credit Facility Agreement and cash on hand. Our next debt maturity of $529 million is not due until 2022. In second quarter 2018, we amended our Credit Facility to, among other things, (i) increase the borrowing base to $1.8 billion with aggregate elected commitments increased to $1.5 billion (ii) extend the maturity date to April 17, 2023, subject to a springing maturity on October 15, 2021 and (iii) decrease the interest rates applicable to the loans under the Credit Facility Agreement (see Note 6 for further discussion). We believe our current liquidity position will provide the necessary capital to develop our assets or should sustain us if there is a downturn.

As we execute on our long-term strategy, we continue to operate with a focus on increasing shareholder value and investing in our businesses in a way that enhances our competitive position by:

- value driven development of our positions in the Delaware and Williston Basins;
- continuing to pursue cost improvements and efficiency gains;
- employing new technology and operating methods;
- continuing to invest in projects to assess resources and add new development opportunities to our portfolio;
- retaining the flexibility to make adjustments to our planned levels and allocation of capital investment expenditures in response to changes in economic conditions or business opportunities; and
- continuing to maintain an active economic hedging program around our commodity price risks.

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

- lower than anticipated energy commodity prices;
- increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation;
- higher capital costs of developing our properties, including the impact of inflation;
- lower than expected levels of cash flow from operations;
- counterparty credit and performance risk;
- general economic, financial markets or industry downturn;
- unavailability of capital either under our revolver or access to capital markets;
- changes in the political and regulatory environments; and
- decreased drilling success.

With the exception of potential impairments, we continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we use master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements. Further, we continue to monitor the long-term market outlooks and forecasts for potential indicators of needed changes to our forecasted oil and natural gas prices. Commodity prices are significantly volatile and prices for a barrel of oil ranged from over $100 per barrel to less than $30 per barrel for a brief time over the past five years. Our forecasted price assumptions reflect a long-term view of pricing but also consider current prices and are consistent with pricing assumptions generally used in evaluating our drilling decisions and acquisition plans. If forecasted oil and natural gas prices were to decline, we would need to review the producing properties net book value for possible impairment. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. If impairments were required, the charges could be significant. The net book value of our proved properties is $4.8 billion. In addition, the net book value associated with unproved leasehold is approximately $2.1 billion and is primarily associated with our Delaware Basin properties. See our discussion of impairment of long-lived assets in our Critical Accounting Estimates discussion in Exhibit 99.1 of our Form 8-K filed May 7, 2018.

Results of Operations
Three Month-Over-Three Month Results of Operations
Revenue analysis

	Three months ended June 30,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2018	2017		
	(Millions)			
Revenues:				
Oil sales	$468	$194	$ 274	141 %
Natural gas sales	16	16	—	— %
Natural gas liquid sales	36	16	20	125 %
Total product revenues	520	226	294	130 %
Net gain (loss) on derivatives	(154)	116	(270)	NM
Commodity management	64	8	56	NM
Total revenues	$430	$350	$ 80	23 %

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

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

- $274 million increase in oil sales reflects $155 million related to higher sales prices and $119 million related to higher production sales volumes for the three months ended June 30, 2018 compared to 2017. The increase in production sales volumes was driven by both our Delaware and Williston Basins. The Delaware Basin volumes were 39.1 MBbls per day compared to 20.2 MBbls per day for the three months ended June 30, 2018 and 2017, respectively. The Williston Basin volumes were 41.7 MBbls per day compared to 30.1 MBbls per day for the three months ended June 30, 2018 and 2017, respectively. The following table reflects oil production prices, the price impact of our derivative settlements and volumes for the three months ended June 30, 2018 and 2017:

	Three months ended June 30,	
	2018	2017
Oil sales (per barrel)	63.63	$42.65
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	(11.47)	2.55
Oil net price including derivative settlements (per barrel)	$52.16	$45.20
Oil production sales volumes (MBbls)	7,352	4,572
Per day oil production sales volumes (MBbls/d)	80.8	50.2

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

- Natural gas sales were flat but reflect $10 million related to lower sales prices offset by $10 million related to higher production sales volumes for the three months ended June 30, 2018 compared to 2017. The following table reflects natural gas production prices, the price impact of our derivative settlements and volumes for the three months ended June 30, 2018 and 2017:

	Three months ended June 30,	
	2018	2017
Natural gas sales (per Mcf)	$1.12	$1.90
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	0.75	0.31
Natural gas net price including derivative settlements (per Mcf)	$1.87	$2.21
Natural gas production sales volumes (MMcf)	13,854	8,357
Per day natural gas production sales volumes (MMcf/d)	152	92

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

- $20 million increase in natural gas liquids sales primarily reflect $12 million related to higher production sales volumes and $8 million related to higher sales prices for the three months ended June 30, 2018 compared to 2017. The increased production primarily relates to the Delaware Basin. The Delaware Basin volumes were 14.2 MBbls per day compared to 8.0 MBbls per day for the three months ended June 30, 2018 and 2017, respectively. The following table reflects NGL production prices, the price impact of our derivative settlements and volumes for the three months ended June 30, 2018 and 2017:

	Three months ended June 30,	
	2018	2017
NGL sales (per barrel)	$20.94	$15.76
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	(2.06)	—
NGL net price including derivative settlements (per barrel)	$18.88	$15.76
NGL production sales volumes (MBbls)	1,713	959
Per day NGL production sales volumes (MBbls/d)	18.8	10.5

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

- $270 million unfavorable change in net gain (loss) on derivatives primarily reflects unfavorable change in crude oil derivatives which was a result of losses in 2018 due to increases in 2018 of forward commodity prices relative to our hedge positions as opposed to gains in 2017 due to decreases in 2017 of forward commodity prices relative to our hedge position at that time. Settlements to be paid on derivatives totaled $78 million and settlements to be received totaled $14 million for three months ended June 30, 2018 and June 30, 2017, respectively.
- $56 million increase in commodity management revenues is primarily due to higher crude sales volumes. A similar increase is reflected in the $46 million increase in related commodity management costs and expenses, discussed below. The increase in crude sales volumes is due to crude oil purchases and sales to fulfill certain sales commitments.

Cost and operating expense and operating income (loss) analysis

	Three months ended June 30, 2018	2017	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change	Per Boe Expense 2018	2017
	(Millions)					
Costs and expenses:						
Depreciation, depletion and amortization	$197	$141	$ (56)	(40)%	$17.31	$20.26
Lease and facility operating	59	41	(18)	(44)%	$5.20	$5.92
Gathering, processing and transportation	20	6	(14)	NM	$1.79	$0.80
Taxes other than income	41	19	(22)	(116)%	$3.67	$2.68
Exploration	17	16	(1)	(6)%		
General and administrative:						
General and administrative expenses	34	36	2	6 %	$3.06	$5.13
Equity-based compensation	10	8	(2)	(25)%	$0.83	$1.27
Total general and administrative	44	44	—	— %	$3.89	$6.40
Commodity management	54	8	(46)	NM		
Net gain—sales of assets	(1)	(7)	(6)	(86)%		
Other—net	2	7	5	71 %		
Total costs and expenses	$433	$275	$ (158)	(57)%		
Operating income (loss)	$(3)	$75	$ (78)	104 %		

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

Significant variances in our costs and expenses are comprised of the following:

- $56 million increase in depreciation, depletion and amortization is primarily due to higher production volumes partially offset by a $2.95 per Boe decrease in rate which was impacted by higher estimated reserves as compared to June 30, 2017 due to a higher 12-month average price, the addition of new wells with lower relative cost per Boe and an increase in Delaware production relative to the overall total.
- $18 million increase in lease and facility operating expenses primarily related to increased production volumes.
- $14 million increase in gathering, processing and transportation primarily due in part to the adoption of ASU 2014-09, Revenue from Contracts with Customers, for which the net expense on certain transportation related arrangements that were recorded as a reduction in oil revenue in 2017 are included in gathering, processing and transportation in 2018 and growth in production volumes.
- $22 million increase in taxes other than income related to increased product revenues, previously discussed.
- $46 million increase in commodity management expenses is primarily due to higher crude purchase volumes. The increase in crude oil purchase volumes is due to crude oil purchases and sales to fulfill certain sales commitments.

Results below operating income (loss)

	Three months ended June 30, 2018	2017	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$(3)	$75	$ (78)	NM
Interest expense	(39)	(46)	7	15 %
Loss on extinguishment of debt	(71)	—	(71)	NM
Investment income and other	1	—	1	NM
Income (loss) from continuing operations before income taxes	(112)	29	(141)	NM
Benefit for income taxes	(33)	(298)	(265)	(89)%
Income (loss) from continuing operations	(79)	327	(406)	NM
Loss from discontinued operations	(2)	(251)	249	99 %
Net income (loss)	$(81)	$76	(157)	NM

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

The decrease in interest expense primarily relates to lower level of debt outstanding in 2018 compared to 2017.

In the second-quarter of 2018, we used proceeds from the San Juan Gallup disposition and proceeds from the issuance of$500 million Senior Notes due in 2026 to retire $921 million aggregate principal amount of our Senior Notes. As a result of the early retirement of these Senior Notes, we recorded a loss on extinguishment of debt of $71 million in second-quarter 2018. See Note 6 of Notes to Consolidated Financial Statements for additional information regarding these transactions.

Benefit for income taxes for the three months ended June 30, 2018 changed unfavorably compared to the same period for 2017. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Loss from discontinued operations in 2017 includes the results of the San Juan Basin. The sale of the San Juan Gallup closed in first quarter 2018 and the sale of the San Juan Legacy closed in fourth-quarter 2017. See Note 2 of Notes to Consolidated Financial Statements for detail of amounts included in discontinued operations.

Six Month-Over-Six Month Results of Operations

Revenue analysis

	Six months ended June 30, 2018	2017	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Oil sales	$828	$353	$ 475	135 %
Natural gas sales	33	33	—	— %
Natural gas liquid sales	66	27	39	144 %
Total product revenues	927	413	514	124 %
Net gain (loss) on derivatives	(223)	319	(542)	NM
Commodity management	100	13	87	NM
Total revenues	$804	$745	$ 59	8 %

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

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

- $475 million increase in oil sales reflects $247 million related to higher sales prices and $228 million related to higher production sales volumes for the six months ended June 30, 2018 compared to 2017. The Delaware Basin volumes were 36.5 MBbls per day compared to 16.9 MBbls per day for the six months ended June 30, 2018 and 2017, respectively. The Williston Basin volumes were 36.8 MBbls per day compared to 27.7 MBbls per day for the six months ended June 30, 2018 and 2017, respectively. The following table reflects oil production prices, the price impact of our derivative settlements and volumes for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,	
	2018	2017
Oil sales (per barrel)	$62.42	$43.81
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	(10.78)	1.05
Oil net price including derivative settlements (per barrel)	$51.64	$44.86
Oil production sales volumes (MBbls)	13,271	8,076
Per day oil production sales volumes (MBbls/d)	73.3	44.6

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

- Natural gas sales were flat but reflect $20 million in higher production sales volumes offset by $20 million related to lower sales prices for the six months ended June 30, 2018 compared to 2017. The increase in our production sales volumes primarily relates to our Delaware Basin which had production volumes of 119 MMcf per day compared to 66 MMcf per day for the six months ended June 30, 2018 compared to 2017, respectively. The following table reflects natural gas production prices, the price impact of our derivative settlements and volumes for the six months ended June 30, 2018 and 2017:

	Six months ended June 30,	
	2018	2017
Natural gas sales (per Mcf)	$1.27	$2.03
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	0.58	0.04
Natural gas net price including derivative settlements (per Mcf)	$1.85	$2.07
Natural gas production sales volumes (MMcf)	25,763	16,104
Per day natural gas production sales volumes (MMcf/d)	142	89

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

- $39 million increase in natural gas liquids sales primarily reflects $22 million related to higher production sales volumes and $17 million related to higher sales prices for the six months ended June 30, 2018 compared to 2017. The Delaware Basin volumes were 12.6 MBbls per day compared to 6.9 MBbls per day for the six months ended June 30, 2018 and 2017, respectively. The Williston Basin volumes were 4.3 MBbls per day compared to 2.3 MBbls per day for the six months ended June 30, 2018 and 2017, respectively. The following table reflects NGL production prices, the price impact of our derivative settlements and volumes for the six months ended June 30, 2018 and 2017:

	Six months ended June 30, 2018	Six months ended June 30, 2017
NGL sales (per barrel)	$21.47	$15.99
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	(1.46)	—
NGL net price including derivative settlements (per barrel)	$20.01	$15.99
NGL production sales volumes (MBbls)	3,053	1,665
Per day NGL production sales volumes (MBbls/d)	16.9	9.2

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

- $542 million unfavorable change in net gain (loss) on derivatives primarily reflects unfavorable change in crude oil derivatives which was a result of losses in 2018 due to increases in 2018 of forward commodity prices relative to our hedge positions as opposed to gains in 2017 due to decreases in 2017 of forward commodity prices relative to our hedge position at that time. Settlements to be paid on derivatives totaled $133 million for the six months ended June 30, 2018 and settlements to be received totaled $9 million for the six months ended June 30, 2017.
- $87 million increase in commodity management revenues primarily due to higher crude sales volumes. A similar increase is reflected in the $80 million increase in related commodity management costs and expenses, discussed below. The increase in crude sales volumes is due to crude oil purchases and sales to fulfill certain sales commitments.

Cost and operating expense and operating income (loss) analysis

	Six months ended June 30, 2018	2017	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change	Per Boe Expense 2018	2017
	(Millions)					
Costs and expenses:						
Depreciation, depletion and amortization	$358	$254	$ (104)	(41)%	$17.34	$20.42
Lease and facility operating	114	77	(37)	(48)%	$5.55	$6.21
Gathering, processing and transportation	38	11	(27)	NM	$1.85	$0.86
Taxes other than income	71	32	(39)	(122)%	$3.46	$2.56
Exploration	36	52	16	31 %		
General and administrative:						
General and administrative expenses	70	70	—	— %	$3.41	$5.60
Equity-based compensation	17	15	(2)	(13)%	$0.82	$1.24
Total general and administrative	87	85	(2)	(2)%	$4.23	$6.84
Commodity management	93	13	(80)	NM		
Net gain—sales of assets	—	(38)	(38)	100 %		
Other—net	4	11	7	64 %		
Total costs and expenses	$801	$497	$ (304)	(61)%		
Operating income	$3	$248	$ (245)	(99)%		

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

Significant variances in our costs and expenses are comprised of the following:

- $104 million increase in depreciation, depletion and amortization is primarily due to higher production volumes partially offset by a $3.08 per Boe decrease in rate which was impacted by higher estimated reserves as compared to June 30, 2017 due to a higher 12-month average price, the addition of new wells with lower relative cost per Boe and an increase in Delaware production relative to the overall total.
- $37 million increase in lease and facility operating expenses primarily related to increased production volumes.
- $27 million increase in gathering, processing and transportation is due in part to the adoption of ASU 2014-09, Revenue from Contracts with Customers, for which the net expense on certain transportation related arrangements that were recorded as a reduction in oil revenue in 2017 are included in gathering, processing and transportation in 2018 and growth in production volumes.
- $39 million increase in taxes other than income related to increased product revenues, previously discussed.
- $16 million decrease in exploration expenses is primarily due to unproved leasehold property impairment, amortization and expiration in 2017 which includes costs associated with certain expired leases in the Delaware Basin in excess of the accumulated amortization balance recorded during first-quarter 2017. See Note 4 of Notes to Consolidated Financial Statements.
- $80 million increase in commodity management expenses is primarily due to higher crude purchase volumes. The increase in crude oil purchase volumes is due to crude oil purchases and sales to fulfill certain sales commitments.
- The absence in 2018 of a $38 million net gain on sales of assets recorded in 2017. See Note 4 of Notes to Consolidated Financial Statements.

Results below operating income (loss)

	Six months ended June 30, 2018	2017	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income	$3	$248	$ (245)	(99)%
Interest expense	(85)	(93)	8	9 %
Loss on extinguishment of debt	(71)	—	(71)	NM
Investment income and other	—	2	(2)	100 %
Income (loss) from continuing operations before income taxes	(153)	157	(310)	NM
Benefit for income taxes	(48)	(265)	(217)	(82)%
Income (loss) from continuing operations	(105)	422	(527)	NM
Loss from discontinued operations	(91)	(254)	163	64 %
Net income (loss)	$(196)	$168	(364)	NM

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

The decrease in interest expense primarily relates to lower level of debt outstanding in 2018 compared to 2017.

In the second-quarter of 2018, we used proceeds from the San Juan Gallup disposition and proceeds from the issuance of$500 million Senior Notes due in 2026 to retire $921 million aggregate principal amount of our Senior Notes. As a result of the early retirement of these Senior Notes, we recorded a loss on extinguishment of debt of $71 million in second-quarter 2018. See Note 6 of Notes to Consolidated Financial Statements for additional information regarding these transactions.

Income taxes for 2018 changed unfavorably compared to 2017. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Loss from discontinued operations in 2018 included a $147 million pretax loss on the sale of our San Juan Gallup operations which was sold in the first quarter of 2018. See Note 2 of Notes to Consolidated Financial Statements for detail of amounts included in discontinued operations.

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Management's Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital and capital expenditures while maintaining a sufficient level of liquidity. Our primary sources of liquidity in 2018 are cash on hand, expected cash flows from operations, proceeds from the sales of the San Juan Basin properties and other non-core assets, and, if necessary, borrowings on our credit facility. We anticipate that the combination of these sources should be sufficient to allow us to pursue our business strategy and goals through at least 2018 which included the reduction of a portion of our Senior Notes (see Note 6 of Notes to Consolidated Financial Statements). Additional sources of liquidity, if needed and if available, include proceeds from asset sales, bank financings and proceeds from the issuance of long-term debt and equity securities. In addition, we may further reduce debt and/or interest expense by seeking to retire, purchase or exchange our outstanding debt through cash purchases and/or exchanges for equity or debt securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

We note the following assumptions for 2018:

- our planned capital expenditures for full-year 2018, excluding acquisitions, are estimated to be approximately $1.3 billion to $1.4 billion of which $1.2 billion to $1.25 billion relate to drilling and completions, including facilities. Additionally, we estimate between $70 million and $85 million for equity investments. As of June 30, 2018, we have incurred $624 million of drilling and completion capital expenditures including facilities (and excluding capital related to discontinued operations); and
- we have hedged a portion of our anticipated 2018 oil and gas production as disclosed in Commodity Price Risk Management following this section.

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

- lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices or inflation on operating costs;
- lower than anticipated proceeds from asset sales;
- significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold;
- reduced access to our credit facility pursuant to our financial covenants; and
- higher than expected development costs, including the impact of inflation.

Credit Facility

On April 17, 2018, the Company entered into a Second Amendment to Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the "Credit Facility"). The Credit Facility, as amended, increases total commitments to $1.5 billion, increases the Borrowing Base to $1.8 billion and extends the maturity date to April 17, 2023. The Credit Facility may become due on October 15, 2021 if available liquidity minus outstanding 2022 notes is less than $500 million. The $1.8 billion Borrowing Base will remain in effect until the next Redetermination Date as set forth in the Credit Facility and, at this time, availability under the Credit Facility Agreement is limited by the total commitments of $1.5 billion. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. One of the significant financial covenants is a ratio of Net Indebtedness to Consolidated EBITDAX of 4.25 to 1.00. For additional information regarding the terms of our Credit Facility see Note 6 of Notes to Consolidated Financial Statements. As of June 30, 2018, we had no borrowings and $65 million of letters of credit issued under the Credit Facility and we were in compliance with our financial covenants under the credit agreement. Our unused borrowing availability was approximately $1,435 million as of June 30, 2018. As of the date of this filing, we are in compliance with all terms, conditions and financial covenants of the Credit Facility, as amended.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing oil and gas properties, we enter into derivative contracts for a portion of our future production (see Note 10 of Notes to Consolidated Financial Statements). We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. For the remainder of 2018 and 2019, we have the following contracts as of the date of this filing shown at weighted average volumes and basin-level weighted average prices:

Crude Oil	Jul - Dec 2018		2019	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed Price Swaps—WTI	57,500	$ 52.82	38,000	$ 53.49
Fixed Price Calls—WTI	13,000	$ 58.89	5,000	$ 54.08
Basis swaps—Midland	14,000	$ (0.77)	21,008	$ (1.16)
Basis swaps—Nymex Calendar Monthly Avg Roll	16,630	$ 0.03	20,000	$ 0.11
Basis swaps—Argus LLS	4,158	$ 7.01	—	$ —
Basis swaps—Magellan East Houston	4,989	$ 6.38	—	$ —

Natural Gas	Jul - Dec 2018		2019	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed Price Swaps—Henry Hub	129	$ 2.99	48	$ 2.87
Fixed Price Calls—Henry Hub	16	$ 4.75	—	$ —
Basis swaps—Permian	48	$ (0.31)	25	$ (0.39)
Basis swaps—Waha	15	$ 0.93	25	$ 1.31
Basis swaps—Houston Ship Channel	43	$ (0.08)	30	$ (0.09)

Natural Gas Liquids	Jul - Dec 2018		2019	
	Volume (Bbls/d)	Weighted Average Price ($/Gal)	Volume (Bbls/d)	Weighted Average Price ($/Gal)
Fixed Price Swaps—Ethane Mont Belvieu	3,300	$ 0.29	—	$ —
Fixed Price Swaps—Propane Conway	900	$ 0.79	—	$ —
Fixed Price Swaps—Propane Mont Belvieu	3,900	$ 0.80	—	$ —
Fixed Price Swaps—Iso Butane Mont Belvieu	700	$ 0.91	—	$ —
Fixed Price Swaps—Normal Butane Mont Belvieu	1,800	$ 0.90	—	$ —
Fixed Price Swaps—Natural Gasoline Mont Belvieu	1,500	$ 1.31	—	$ —

Sources (Uses) of Cash

	Six months ended June 30,	
	2018	2017
	(Millions)	
Net cash provided by (used in):		
Operating activities	$428	$142
Investing activities	3	(1,305)
Financing activities	(516)	678
Net decrease in cash and cash equivalents and restricted cash	$(85)	$(485)

Operating activities

Net cash provided by operating activities increased for the six months ended June 30, 2018 compared to the same period in 2017 primarily due to higher commodity prices and higher production volumes in 2018, partially offset by higher payments on derivatives settlements and higher operating costs. Excluding changes in working capital, total cash provided by operating

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activities related to discontinued operations was approximately $45 million and $55 million for the six months ended June 30, 2018 and 2017, respectively. In addition, cash outflows related to Powder River Basin gathering and transportation contracts retained by WPX were $28 million and $29 million for the six months ended June 30, 2018 and 2017, respectively.

Investing activities

The table below includes cash and incurred capital expenditures for drilling and completions and capital expenditures excluding facilities for land acquisitions.

	Six months ended June 30,	
	2018	2017
Cash capital expenditures for drilling and completions:		
Continuing operations	$588	$343
Discontinued operations	25	73
Total	$613	$416
Capital expenditures incurred for drilling and completions:		
Continuing operations	$624	$363
Discontinued operations	23	94
Total	$647	$457
Land acquisitions	$10	$62

Net cash provided by investing activities for the six months ended June 30, 2018 includes $648 million of net proceeds from the sale of San Juan Gallup (see Note 2 of Notes to Consolidated Financial Statements). Net cash used by investing activities for the six months ended June 30, 2017 includes $798 million related to the closing of the Panther acquisition in March 2017.

Financing activities

Net cash used in financing activities for the six months ended June 30, 2018 includes $986 million of payments for retirement of long-term debt, including approximately $63 million of premium partially offset by $494 million net proceeds from a debt issuance in the second quarter of 2018. See Note 6 of Notes to Consolidated Financial Statements for further discussion of our debt tender offers and debt issuance.

Net cash provided by financing activities for the six months ended June 30, 2017 was primarily due to an equity offering of 51.675 million shares for net proceeds of approximately $670 million and net borrowings under the Credit Facility of $25 million.

Net cash provided by (used in) financing activities for the six months ended June 30, 2018 and 2017 also includes payment for shares withheld for taxes of $12 million and $10 million, respectively.

Contractual Obligations

See Note 2 for a discussion of commitments that will be assumed by the purchaser of our San Juan Gallup assets and a related existing performance guarantee from WPX that will remain in place.

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, 2018 or at December 31, 2017.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is primarily related to our debt portfolio and has not materially changed during the first six months of 2018.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of oil, natural gas and natural gas liquids as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our marketing trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Notes 9 and 10 of Notes to Consolidated Financial Statements.

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

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

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

Trading

We currently have no derivative contracts other than the nontrading derivatives discussed below.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our energy commodity purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net liability of $267 million and $177 million at June 30, 2018 and December 31, 2017, respectively.

The value at risk for derivative contracts held for nontrading purposes was $45 million at June 30, 2018 and $56 million at December 31, 2017. During the last 12 months, our value at risk for these contracts ranged from a high of $56 million to a low of $44 million.

Item 4. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

There have been no changes during the second quarter of 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Note 8 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2017, includes certain risk factors that could materially affect our business, financial condition or future results. Those risk factors have not materially changed as of June 30, 2018.

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

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

EXHIBITS

Exhibit No.	Description
2.1**	Agreement and Plan of Merger, dated October 2, 2014, by and among Pluspetrol Resources Corporation, Pluspetrol Black River Corporation and Apco Oil and Gas International Inc. (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on October 7, 2014)
2.2**	Agreement and Plan of Merger, dated as of July 13, 2015, by and among RKI Exploration & Production, LLC, WPX Energy, Inc. and Thunder Merger Sub LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
2.3**	Membership Interest Purchase Agreement by and Among WPX Energy Holdings, LLC, as Seller, WPX Energy, Inc., solely for purposes of Section 14.15, and Terra Energy Partners LLC, as Purchaser, dated February 8, 2016 (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 9, 2016)
2.4**	Purchase and Sale Agreement, dated as of January 12, 2017, by and among RKI Exploration & Production, LLC, Panther Energy Company II, LLC and CP2 Operating, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on March 13, 2017)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
3.3	Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on March 21, 2014)
3.4	Certificate of Designations for 6.25% Series A Mandatory Convertible Preferred Stock (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current Report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
4.2	Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.3	First Supplemental Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)

4.4	Second Supplemental Indenture, dated as of July 22, 2015, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
4.5	Third Supplemental Indenture, dated as of May 23, 2018, between WPX Energy, Inc. and the Bank of New York Mellon Trust Company, N.A. as trustee (incorporated by reference to Exhibit 4.1 to WPX Energy, Inc's Current Report on Form 8-K filed with the SEC on May 23, 2018)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
10.4	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 29, 2013) (1)

Exhibit No.	Description
10.5	WPX Energy, Inc. Amended 2011 Employee Stock Purchase Plan (incorporated herein by reference to Appendix B to WPX Energy, Inc.'s definitive proxy statement on Schedule 14A (File No. 001-35322) filed with the SEC on March 29, 2018) (1)
10.6	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.7	Form of Restricted Stock Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.8	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, 2014) (1)
10.9	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2015) (1)
10.10	Form of Stock Option Agreement between WPX Energy, Inc. and Section 16 Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.11	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.12	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.13	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on December 17, 2013)
10.14	Employment Agreement, dated April 29, 2014, between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.15	Form of Nonqualified Stock Option Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.16	Form of 2014 Time-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)

10.17	Form of 2014 Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.18	Form of Time-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.5 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.19	Form of Performance-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.6 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.20	Form of Restricted Stock Unit Award between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)

Exhibit No.	Description
10.21	Separation and Release Agreement, dated July 28, 2014, between WPX Energy, Inc. and James J. Bender (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.22	Amended and Restated Credit Agreement, dated as of October 28, 2014, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on November 3, 2014)
10.23	Form of Voting and Support Agreement, dated as of July 13, 2015, by and between WPX Energy, Inc. and the Member signatory thereto (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
10.24	First Amendment to the Amended and Restated Credit Agreement, dated as of July 16, 2015, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as existing Administrative Agent and existing Swingline Lender, and Wells Fargo Bank, National Association, as successor Administrative Agent and successor Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
10.25	Commitment Increase Agreement for Amended and Restated Credit Agreement, dated as of July 31, 2015, among WPX Energy, Inc., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, and the Issuing Banks thereto (incorporated by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on August 6, 2015)
10.26	Registration Rights Agreement dated August 17, 2015, among WPX Energy, Inc. and the signatures thereto (incorporated herein by reference to Exhibit 10.35 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015)
10.27	Second Amendment to the Amended and Restated Credit Agreement, dated as of March 18, 2016, by and among WPX Energy, Inc., as the borrower thereunder, the financial institutions party thereto from time to time, as lenders, and Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on March 22, 2016)
10.28	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.32 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016) (1)
10.29	Form of Severance and Restrictive Covenant Agreement between WPX Energy, Inc. and Marcia MacLeod (incorporated herein by reference to Exhibit 10.33 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016) (1)
10.30	Form of Severance and Restrictive Covenant Agreement between WPX Energy, Inc. and Michael Fiser (incorporated herein by reference to Exhibit 10.33 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2016) (1)

10.31	Form of Amended and Restated Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on November 16, 2016) (1)
10.32	Form of Amended and Restated Change in Control Agreement between WPX Energy, Inc. and Tier One Executives*(1)
10.33	Amended and Restated WPX Energy Executive Severance Pay Plan*(1)
10.34	Purchase and Sale Agreement by and Among WPX Energy Production, LLC and Enduring Resources IV, LLC dated January 30, 2018 (incorporated by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 5, 2018)
10.35	WPX Energy, Inc. 2013 Incentive Plan, as amended (incorporated by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 19, 2018)
10.36	Form of Amended and Restated Restricted Stock Agreement between WPX Energy, Inc. and Executive Officers (incorporated by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 19, 2018)
10.37	Form of Amended and Restated Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 19, 2018)

Exhibit No.	Description
10.38	Second Amendment to the Second Amended and Restated Credit Agreement and First Amendment to Guaranty and Collateral Agreement dated April 17, 2018, by and among the Company and certain of its wholly-owned subsidiaries signatory thereto, Wells Fargo Bank, National Association, as lender, Swingline Lender and Administrative Agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on April 20, 2018)
10.39	Amendment No. 3 to the WPX Energy, Inc. 2013 Incentive Plan (incorporated by reference to Appendix A to WPX Energy, Inc.'s definitive proxy statement on Schedule 14A (File No. 001-35322) filed with the SEC on March 29, 2018)
10.40	Form of Amendment to Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers*(1)
12*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

** All schedules to the Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished to the SEC upon request

(1) Management contract or compensatory plan or arrangement

SIGNATURE

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

WPX Energy, Inc.
(Registrant)

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

Date: August 2, 2018