EP Energy Corp
Form 10-Q
October 30, 2015
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015
OR
o 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 001-36253

EP Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	46-3472728 (I.R.S. Employer Identification No.)
1001 Louisiana Street Houston, Texas (Address of Principal Executive Offices)	77002 (Zip Code)

Telephone Number: (713) 997-1000
Internet Website: www.epenergy.com

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 x No o

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

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

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class A Common Stock, par value $0.01 per share. Shares outstanding as of October 20, 2015: 247,998,083

Class B Common Stock, par value $0.01 per share. Shares outstanding as of October 20, 2015: 801,833

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Below is a list of terms that are common to our industry and used throughout this document:

/d	=	per day
Bbl	=	barrel
Boe	=	barrel of oil equivalent
Gal	=	gallons
LLS	=	light Louisiana sweet crude oil
MBoe	=	thousand barrels of oil equivalent
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
MMBtu	=	million British thermal units
MMBbls	=	million barrels
MMcf	=	million cubic feet
MMGal	=	million gallons
NGLs	=	natural gas liquids
NYMEX	=	New York Mercantile Exchange
TBtu	=	trillion British thermal units
WTI	=	West Texas intermediate

When we refer to oil and natural gas in "equivalents", we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil and/or NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", "the Company" or "EP Energy", we are describing EP Energy Corporation and/or subsidiaries.

All references to "common stock" herein refer to Class A common stock.

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CAUTIONARY STATEMENTS FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words "believe", "expect", "estimate", "anticipate" and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- capital and other expenditures;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic and operating performance;
- operating income;
- management's plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these differences can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in our forward-looking statements are described in our 2014 Annual Report on Form 10-K. There have been no material changes to the risk factors described in the Form 10-K.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EP ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)
(Unaudited)

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Operating revenues				
Oil	$245	$474	$781	$1,341
Natural gas	58	67	152	220
NGLs	16	31	44	88
Financial derivatives	434	381	458	(44)
Total operating revenues	753	953	1,435	1,605
Operating expenses				
Natural gas purchases	9	8	24	16
Transportation costs	30	22	82	71
Lease operating expense	45	48	139	142
General and administrative	32	33	114	208
Depreciation, depletion and amortization	260	228	737	634
Impairment charges	—	1	—	1
Exploration and other expense	2	5	14	18
Taxes, other than income taxes	20	35	65	102
Total operating expenses	398	380	1,175	1,192
Operating income	355	573	260	413
Loss on extinguishment of debt	—	—	(41)	(17)
Interest expense	(84)	(76)	(249)	(235)
Income (loss) from continuing operations before income taxes	271	497	(30)	161
Income tax expense (benefit)	95	191	(13)	67
Income (loss) from continuing operations	176	306	(17)	94
(Loss) income from discontinued operations, net of tax	—	(1)	—	3
Net income (loss)	$176	$305	$(17)	$97
Basic and diluted net income (loss) per common share				
Income (loss) from continuing operations	$0.72	$1.25	$(0.07)	$0.39
Income from discontinued operations, net of tax	—	—	—	0.01
Net income (loss)	$0.72	$1.25	$(0.07)	$0.40
Basic and diluted weighted average common shares outstanding	244	244	244	241

See accompanying notes.

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions)
(Unaudited)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$28	$22
Accounts receivable		
Customer, net of allowance of $1 in 2015 and less than $1 in 2014	209	234
Other, net of allowance of $1 in 2015 and 2014	18	38
Income tax receivable	1	24
Materials and supplies	25	25
Derivative instruments	672	752
Prepaid assets	8	7
Total current assets	961	1,102
Property, plant and equipment, at cost		
Oil and natural gas properties	11,359	10,241
Other property, plant and equipment	81	76
	11,440	10,317
Less accumulated depreciation, depletion and amortization	2,316	1,589
Total property, plant and equipment, net	9,124	8,728
Other assets		
Derivative instruments	181	297
Unamortized debt issue costs	84	90
Other	2	2
	267	389
Total assets	$10,352	$10,219

See accompanying notes.

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions)
(Unaudited)

	September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 102	$ 142
Other	213	403
Deferred income taxes	233	251
Derivative instruments	1	1
Accrued interest	102	53
Asset retirement obligations	1	2
Other accrued liabilities	48	47
Total current liabilities	700	899
Long-term debt	4,931	4,598
Other long-term liabilities		
Deferred income taxes	331	327
Asset retirement obligations	39	40
Other	6	7
Total non-current liabilities	5,307	4,972
Commitments and contingencies (Note 8)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 248 million shares issued and outstanding at September 30, 2015; 245 million shares issued and outstanding at December 31, 2014	2	2
Class B shares, $0.01 par value; 0.8 million shares authorized, issued and outstanding at September 30, 2015 and December 31, 2014	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Additional paid-in capital	3,524	3,510
Retained earnings	819	836
Total stockholders' equity	4,345	4,348
Total liabilities and equity	$ 10,352	$ 10,219

See accompanying notes.

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Nine months ended September 30, 2015	2014
Cash flows from operating activities		
Net (loss) income	$(17)	$97
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Depreciation, depletion and amortization	737	642
Impairment charges	—	19
Deferred income tax (benefit) expense	(14)	60
Loss on extinguishment of debt	41	17
Share-based compensation expense	14	12
Non-cash portion of exploration expense	10	15
Amortization of debt issuance costs	14	16
Other	—	1
Asset and liability changes		
Accounts receivable	45	5
Accounts payable	(56)	(7)
Derivative instruments	196	(16)
Accrued interest	49	52
Other asset changes	21	4
Other liability changes	(1)	(11)
Net cash provided by operating activities	1,039	906
Cash flows from investing activities		
Capital expenditures	(1,203)	(1,521)
Proceeds from the sale of assets, net of cash transferred	—	126
Cash paid for acquisitions, net of cash acquired	(114)	(154)
Net cash used in investing activities	(1,317)	(1,549)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	1,777	1,835
Repayments of long-term debt	(1,473)	(1,895)
Proceeds from issuance of stock	—	669
Debt issuance costs	(19)	—
Other	(1)	—
Net cash provided by financing activities	284	609
Change in cash and cash equivalents	6	(34)
Cash and cash equivalents		
Beginning of period	22	51
End of period	$28	$17

See accompanying notes

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(In millions)
(Unaudited)

	Stockholders' Equity Class A Stock		Class B Stock				
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Total
Balance at December 31, 2014	245	$2	0.8	$—	$3,510	$836	$4,348
Share-based compensation	3	—	—	—	14	—	14
Net loss	—	—	—	—	—	(17)	(17)
Balance at September 30, 2015	248	$2	0.8	$—	$3,524	$819	$4,345

See accompanying notes.

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EP ENERGY CORPORATION
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC) and in accordance with United States generally accepted accounting principles (U.S. GAAP) as it applies to interim financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP and should be read along with our 2014 Annual Report on
Form 10-K. The condensed consolidated financial statements as of September 30, 2015 and 2014 are unaudited. The consolidated balance sheet as of December 31, 2014 has been derived from the audited consolidated balance sheet included in our 2014 Annual Report on Form 10-K. In our opinion, all adjustments which are of a normal, recurring nature are reflected to fairly present these interim period results. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Significant Accounting Policies

There were no changes in significant accounting policies as described in the 2014 Annual Report on Form 10-K.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet been adopted.

Business Combinations. In September 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement - Period Adjustments, which eliminates the requirement for an acquirer in a business combination to retrospectively adjust prior period financial statements for adjustments to the initial purchase price allocation that are identified between the acquisition date and when the purchase price allocation is finalized. Prospective application of this standard is required beginning after December 15, 2015 and early adoption is allowed.

Debt Issuance Costs. In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which will require us to present unamortized debt issue costs on our balance sheet as a direct deduction from the associated debt liability. In August 2015, the FASB issued ASU No. 2015-15, Interest- Imputation of Interest, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements, which clarifies that an entity may defer and present debt issue costs related to line-of-credit arrangements as an asset regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. Retrospective application of these standards is required beginning in the first quarter of 2016 and early adoption is allowed.

Revenue Recognition. In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which clarifies the principles for recognizing revenue and develops a common revenue standard for U.S. GAAP and International Financial Reporting Standards. In July 2015, the FASB approved the deferral of the new revenue standard by one year, with the option of early adoption in 2017 or, if not adopted early, beginning in the first quarter of 2018. Retrospective application of this standard is required upon adoption. We are currently evaluating the impact, if any, that this update will have on our financial statements.

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2. Acquisitions and Divestitures

Acquisitions. On September 4, 2015, we acquired approximately 12,000 net acres adjacent to our existing Eagle Ford Shale acreage for an adjusted cash purchase price of approximately $114 million. Our consolidated balance sheet presented as of September 30, 2015, reflects our preliminary allocation of the purchase price to the underlying acquired properties. No goodwill or bargain purchase was recorded on the acquisition.
Discontinued Operations. In 2014, we reflected as discontinued operations certain assets sold, including domestic natural gas assets in the Arklatex and South Louisiana Wilcox areas and our Brazilian operations. We classified the results of operations of these assets prior to their sale in 2014 as income (loss) from discontinued operations.
Summarized operating results of our discontinued operations were as follows:

	Quarter ended September 30, 2014	Nine months ended September 30, 2014
	(in millions)	
Operating revenues	$14	$82
Operating expenses		
Transportation costs	—	5
Lease operating expense	6	31
Depreciation, depletion and amortization	—	8
Impairment charges(1)	3	18
Other expense	4	17
Total operating expenses	13	79
Loss on sale of assets	(1)	—
Other (expense) income	(1)	4
(Loss) income from discontinued operations before income taxes	(1)	7
Income tax expense	—	4
(Loss) income from discontinued operations, net of tax	$(1)	$3

(1) During the quarter and nine months ended September 30, 2014, we recorded $3 million and $18 million in impairment charges related to the sale of our Brazilian operations.

3. Income Taxes

Effective Tax Rate. Interim period income taxes are computed by applying an anticipated annual effective tax rate to year-to-date income or loss, except for significant unusual or infrequently occurring items, which are recorded in the period in which they occur. Changes in tax laws or rates are recorded in the period they are enacted.
For the quarter and nine months ended September 30, 2015, our effective tax rates were 35% and 42%, respectively. Our effective tax rate for the nine months ended September 30, 2015 differs from the statutory rate primarily as a result of the effects of state income taxes (net of federal income tax effects) relative to our level of pre-tax book income (loss). Our effective tax rates for the quarter and nine months ended September 30, 2014 were 38% and 42%, respectively, and differed from the statutory rate as a result of the tax effects of state income taxes, non-deductible compensation expense and certain transaction costs related to our initial public offering. Generally, the Company's and certain subsidiaries' income tax years remain open and subject to examination by both federal and state tax authorities. In the third quarter of 2015, we were notified of an IRS examination of one of our subsidiary's 2013 U.S. tax return.

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4. Earnings Per Share

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. Potentially dilutive securities consist of our employee stock options and restricted stock which did not have a material effect upon our diluted earnings per share for both the quarters ended September 30, 2015 and 2014 and the nine months ended September 30, 2014. For the nine months ended September 30, 2015, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

5. Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments:

	September 30, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt	$4,931	$4,374	$4,598	$4,582
Derivative instruments	$852	$852	$1,048	$1,048

As of September 30, 2015 and December 31, 2014, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long-term debt obligations (see Note 7) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk.

Oil, Natural Gas and NGLs Derivative Instruments. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas through the use of financial derivatives. As of September 30, 2015 and December 31, 2014, we had fixed price derivative contracts for 29 MMBbls and 37 MMBbls of oil and 23 TBtu and 69 TBtu of natural gas, respectively. In addition, we have derivative contracts related to locational basis differences and/or timing of physical settlement prices. As of September 30, 2015, we also had derivative contracts on 27 MMGal of propane. None of these contracts are designated as accounting hedges.

The following table reflects the volumes associated with derivative contracts entered into between October 1, 2015 and October 27, 2015.

	2017 Volumes
Oil (MBbls)	
Basis Swaps	
LLS vs. Brent[1]	365

(1) EP Energy receives Brent plus the basis spread and pays LLS.

Interest Rate Derivative Instruments. We have interest rate swaps with a notional amount of $600 million that extend through April 2017 and are intended to reduce variable interest rate risk. As of September 30, 2015, we had a net liability of $2 million and as of December 31, 2014, we had a net asset of $3 million related to interest rate derivative instruments included in our consolidated balance sheets. For the quarters ended September 30, 2015 and 2014, we recorded $2 million of interest expense and $2 million of interest income, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments. For the nine months ended September 30, 2015 and 2014, we recorded $7 million and $2 million of interest expense, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments.

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Fair Value Measurements. We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of September 30, 2015 and December 31, 2014, all derivative financial instruments were classified as Level 2. Our assessment of the level of an instrument can change over time based on the maturity or liquidity of the instrument.

Financial Statement Presentation. The following table presents the fair value associated with our derivative financial instruments as of September 30, 2015 and December 31, 2014. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

	Level 2 Derivative Assets				Derivative Liabilities			
			Balance Sheet Location				Balance Sheet Location	
	Gross Fair Value	Impact of Netting	Current	Non-current	Gross Fair Value	Impact of Netting	Current	Non-current
	(in millions)				(in millions)			
September 30, 2015								
Derivative instruments	$874	$(21)	$672	$181	$(22)	$21	$(1)	$—
December 31, 2014								
Derivative instruments	$1,093	$(44)	$752	$297	$(45)	$44	$(1)	$—

For the quarters ended September 30, 2015 and 2014, we recorded derivative gains of $434 million and $381 million, respectively, on our financial oil, natural gas and NGLs derivative instruments. For the nine months ended September 30, 2015 and 2014, we recorded a derivative gain of $458 million and a derivative loss of $44 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statement.

6. Property, Plant and Equipment

Oil and Natural Gas Properties. As of September 30, 2015 and December 31, 2014, we had approximately $9.1 billion and $8.7 billion of total property, plant, and equipment, net of accumulated depreciation, depletion and amortization on our balance sheet, substantially all of which related to both proved and unproved oil and natural gas properties. As of September 30, 2015, our capitalized costs related to proved properties by area were approximately $5 billion in Eagle Ford, $2 billion in Wolfcamp and $1 billion in Altamont. At September 30, 2015 and December 31, 2014, the costs associated with unproved oil and natural gas properties totaled approximately $0.5 billion and $0.7 billion, respectively. During the nine months ended September 30, 2015, we transferred approximately $0.2 billion from unproved properties to proved properties. For the quarters ended September 30, 2015 and 2014, we recorded $1 million and $4 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. For the nine months ended September 30, 2015 and 2014, we recorded $9 million and $15 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of September 30, 2015 or December 31, 2014.
Forward commodity prices play a significant role in determining impairments of proved or unproved property costs. Oil and natural gas prices are inherently volatile and decreased significantly during the latter part of 2014 and throughout 2015. For the quarter and nine months ended September 30, 2015, we did not record an impairment of our

oil and natural gas properties, although the difference between the undiscounted cash flows and the carrying cost of those properties has narrowed significantly. Commodity prices have remained volatile subsequent to September 30, 2015 and have generally declined. Assuming forward commodity prices as of October 27, 2015, but holding all other factors constant as of September 30, 2015, we would not have experienced an impairment of our proved oil and natural gas properties. However, further price declines from these levels and/or changes to our future capital, production rates, levels of proved reserves and development plans as a consequence of the lower price environment, may result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant.

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Leasehold acquisition costs associated with non-producing areas are assessed for impairment based on our estimated drilling plans and capital expenditures relative to potential lease expirations. Our unproved property costs were approximately $0.5 billion at September 30, 2015, of which approximately $0.4 billion was associated with Wolfcamp and $0.1 billion with Altamont. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing exploration and development activities. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g. the current low oil price environment), the availability of oilfield services and the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives. We have drilling commitments on our Wolfcamp acreage that obligate us to drill a specified number of wells by March 31, 2018. Because of the current oil price environment, we reduced our expected capital expenditures in Wolfcamp in 2015 and in other operating areas where we have leasehold costs, and may continue to do so until prices return to more economic levels. Our ability to retain our leases and thus recover our non-producing leasehold costs will be dependent upon a number of factors including our levels of drilling activity, which may include drilling the acreage on our own behalf or jointly with partners, or our ability to modify or extend these leases. Currently, we believe we have the intent and ability to fulfill our drilling commitments prior to the expiration of the associated leases. Should oil prices not justify sufficient capital allocation to the continued development of properties where we have unproved property costs, we could incur impairment charges of our unproved property, and such charges could be material.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We settle these obligations when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue these obligations when we can estimate the timing and amount of their settlement.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate primarily between 7-9 percent and a projected inflation rate of 2.5 percent. The net asset retirement liability as of September 30, 2015 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through September 30, 2015 were as follows:

	2015 (in millions)
Net asset retirement liability at January 1	$42
Liabilities incurred	4
Liabilities settled	(2)
Accretion expense	2
Changes in estimate	(6)
Net asset retirement liability at September 30	$40

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for the quarter and nine months ended September 30, 2015 was approximately $3 million and $12 million, respectively. Capitalized interest for the quarter and nine months ended September 30, 2014 was approximately $6 million and $16 million, respectively.

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7. Long-Term Debt

Listed below are our debt obligations as of the periods presented:

	Interest Rate	September 30, 2015	December 31, 2014
		(in millions)	
$2.75 billion RBL credit facility - due May 24, 2019	Variable	$1,135	$852
Senior secured term loan - due May 24, 2018(1)(3)	Variable	496	496
Senior secured term loan - due April 30, 2019(2)(3)	Variable	150	150
Senior secured notes - due May 1, 2019	6.875%	—	750
Senior unsecured notes - due May 1, 2020	9.375%	2,000	2,000
Senior unsecured notes - due September 1, 2022	7.75%	350	350
Senior unsecured notes - due June 15, 2023	6.375%	800	—
Total		$4,931	$4,598

(1) The term loan was issued at 99% of par and carries interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of September 30, 2015 and December 31, 2014, the effective interest rate of the term loan was 3.50%.

(2) The term loan carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of September 30, 2015 and December 31, 2014, the effective rate for the term loan was 4.50%.

(3) The term loans are secured by a second priority lien on all of the collateral securing the RBL credit facility, and effectively rank junior to any existing and future first lien secured indebtedness of the Company.

During the second quarter of 2015, we issued $800 million of 6.375% senior unsecured notes due in June 2023. We used a substantial portion of the proceeds from the offering to purchase for cash our $750 million senior secured notes due in 2019. In conjunction with repurchasing these notes, we recorded a $41 million loss on extinguishment of debt, of which $12 million was a non-cash expense related to eliminating associated unamortized debt issuance costs.

During the first quarter of 2014, we recorded a $17 million non-cash loss on extinguishment of debt upon retiring our senior PIK toggle note with a portion of the proceeds from our initial public offering.

As of September 30, 2015 and December 31, 2014, we had $84 million and $90 million, respectively, in deferred financing costs on our consolidated balance sheets. During the second quarter 2015, we recorded an additional $19 million in deferred financing costs in conjunction with the issuance of our $800 million of 6.375% senior unsecured notes and with the extension of our Reserve-based Loan facility (RBL Facility). During the quarters ended September 30, 2015 and 2014, we amortized $4 million and $5 million, respectively, of deferred financing costs into interest expense. During the nine months ended September 30, 2015 and 2014, we amortized $14 million and $16 million, respectively, of deferred financing costs into interest expense.

$2.75 Billion Reserve-based Loan. We have a $2.75 billion credit facility in place which allows us to borrow funds or issue letters of credit (LCs). As of September 30, 2015, we had approximately $82 million of LC's issued under the facility in addition to amounts borrowed with $1.53 billion of available capacity.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In April 2015, we completed our semi-annual redetermination, reaffirming the borrowing base at $2.75 billion and extending the maturity date to May 2019, provided that our 2018 and 2019 secured term loans are retired or refinanced six months prior to their maturity. Our next redetermination date is in November 2015. Downward revisions of our oil and natural gas reserves due to declines in commodity prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base which could negatively impact our borrowing capacity under the RBL Facility in the future.

Restrictive Provisions/Covenants. The availability of borrowings under our credit agreements and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions. There have been no significant changes to our restrictive covenants, and as of September 30, 2015, we were in compliance with all of our debt covenants. For a further discussion of our debt agreements and restrictive covenants, see our 2014 Annual Report on Form 10-K.

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8. Commitments and Contingencies

Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each matter, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of our current matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure and adjust our accruals accordingly, and these adjustments could be material. As of September 30, 2015, we had approximately $3 million accrued for all outstanding legal matters.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestitures of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the recent decline in commodity prices may create an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we could be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. As of September 30, 2015, we had approximately $7 million accrued related to these indemnifications and other matters.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the Environmental Protection Agency (EPA), issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements.

The environmental laws and regulations to which we are subject also require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2015, we had accrued and had exposure of approximately $1 million for related environmental remediation costs associated with onsite, offsite and groundwater technical studies and for related environmental legal costs. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued. Second, where the most likely outcome cannot be estimated, a range of costs is established and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

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Climate Change and Other Emissions. The EPA and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a "tailoring" rule to regulate GHG emissions, the U.S. Supreme Court partially invalidated it in an opinion decided June 2014. The tailoring rule remains applicable for those facilities considered major sources of six other "criteria" pollutants and at this time we do not expect a material impact to our existing operations from the rule. Any regulations regarding GHG emissions would likely increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric-driven compression at facilities to obtain regulatory permits and approvals in a timely manner.

As part of the White House's Climate Action Plan Strategy to Reduce Methane Emissions, the EPA and the Pipeline and Hazardous Materials Safety Administration (PHMSA) have recently proposed new regulations affecting the oil and gas industry. On September 18, 2015, the EPA published several proposed regulations under the Clean Air Act to reduce methane and volatile organic compounds emissions, in part through green completions at oil wells, fugitive emission surveys, limits on pneumatic pumps and controllers, and draft guidelines for controls on equipment in ozone nonattainment areas. On October 1, 2015, the PHMSA released a proposed rule for oil pipelines, in part requiring inspections in areas affected by natural disasters, expanding use of leak detection systems, and increased use of inline inspection tools. Although we are examining these proposed regulations, it is uncertain what impact they might have on our operations until they are implemented.

Air Quality Regulations. The EPA has promulgated various performance and emission standards that mandate air pollutant emission limits and operating requirements for stationary reciprocating internal combustion engines and process equipment. We do not anticipate material capital expenditures to meet these requirements.

In August 2012, the EPA promulgated additional standards to reduce various air pollutants associated with hydraulic fracturing of natural gas wells and equipment including compressors, storage vessels, and pneumatic valves. Parts of the new standard were amended August 2013. We do not anticipate material capital expenditures to meet these requirements. Effective December 31, 2014, additional amendments to the new standard were finalized, for which we do not anticipate material capital expenditure.

The EPA has promulgated regulations to require pre-construction permits for minor sources of air emissions on tribal lands as of September 2, 2014. On May 22, 2014, the EPA extended this deadline to March 2, 2016, during which time the EPA anticipated separate rulemaking to create general permits for true minor sources in the oil and gas production industry. On September 18, 2015, the EPA again extended the deadline to October 3, 2016 and proposed a federal implementation plan (FIP) rather than a general permit. The proposed FIP incorporates emission limits and other requirements from six standards under the Clean Air Act for the oil and gas industry. Additionally, the proposed FIP would require an operator to document compliance with the Endangered Species Act and National Historic Preservation Act. Until such regulations are finalized, it is uncertain what impact they might have on our operations on tribal lands.

Hydraulic Fracturing Regulations. We use hydraulic fracturing extensively in our operations. Various regulations have been adopted and proposed at the federal, state and local levels to regulate hydraulic fracturing operations. These regulations range from banning or substantially limiting hydraulic fracturing operations, requiring disclosure of the hydraulic fracturing fluids and requiring additional permits for the use, recycling and disposal of water used in such operations. In addition, various agencies, including the EPA and Department of Energy are reviewing changes in their regulations to address the environmental impacts of hydraulic fracturing operations. Until such regulations are implemented, it is uncertain what impact they might have on our operations. In March 2015, the BLM published final rules for hydraulic fracturing on federal and certain tribal lands, including use of tanks for recovered water, updated cementing and testing requirements, and disclosure of chemicals used in hydraulic fracturing. Several states and the Ute Indian Tribe have filed suit to challenge these rules, and on September 30, 2015, a federal court issued a preliminary injunction suspending the rules. No material cost is expected for the Company's 2015 program.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (PRP) with respect to one active site under the CERCLA or state equivalents. As of September 30, 2015, we have estimated our share of the remediation costs at this site to be less than $1 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these matters are included in the reserve for environmental matters discussed above.

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Waste Handling. Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements imposed under the Resource Conservation and Recovery Act, as amended, and comparable state laws. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

9. Long-Term Incentive Compensation

Our long-term incentive (LTI) programs currently include a cash-based incentive and certain equity-based compensation awards, as further described in our 2014 Annual Report on Form 10-K. A summary of the changes in our non-vested restricted shares for the nine months ended September 30, 2015 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2014	1,033,394	$ 19.80
Granted	3,628,479	9.46
Vested	(331,682)	19.63
Forfeited	(363,536)	12.05
Non-vested at September 30, 2015	3,966,655	$ 11.07

We record compensation expense on our LTI awards as general and administrative expense over the requisite service period, net of estimates of forfeitures. Pre-tax compensation expense related to all of our LTI awards (both equity-based and cash-based) was approximately $5 million and $15 million during the quarter and nine months ended September 30, 2015, respectively, and approximately $2 million and $19 million during the quarter and nine months ended September 30, 2014. As of September 30, 2015, we had unrecognized compensation expense of $57 million. We will recognize an additional $5 million related to our outstanding awards during the remainder of 2015, $36 million over the remaining requisite service periods subsequent to 2015 and $16 million upon a specified capital transaction when the right to such amounts becomes non-forfeitable.

10. Related Party Transactions

Affiliate Supply Agreement. For the nine months ended September 30, 2015, we have recorded approximately $60 million in capital expenditures for amounts expended under two supply agreements entered into with an affiliate of Apollo Global Management, LLC (Apollo) to provide certain fracturing materials to our Eagle Ford drilling operations.

Management Fee Agreement. In January 2014, we paid a quarterly management fee of $6.25 million to our private equity investors (affiliates of Apollo, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively the Sponsors). Additionally, upon the closing of our initial public offering in January 2014, we paid the Sponsors an additional transaction fee equal to approximately $83 million. We recorded both of these fees in general and administrative expense. Our Management Fee Agreement with the Sponsors, including the obligation to pay the quarterly management fee, terminated automatically in accordance with its terms upon the closing of our initial public offering in January 2014.

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

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 1 of Part I of this Quarterly Report on Form 10-Q. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the "Risk Factors" section of our 2014 Annual Report on Form 10-K. Actual results may differ materially from those contained in any forward-looking statements. The quarter and nine months ended September 30, 2014 included in these interim financial statements present our Brazilian operations and certain domestic natural gas assets sold as discontinued operations. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", "us" and "the Company" refer to EP Energy Corporation and each of its consolidated subsidiaries.

Our Business

Overview. We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We are focused on creating shareholder value through the development of our low-risk drilling inventory located in four areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Altamont Field in the Uinta Basin (Northeastern Utah) and the Haynesville Shale (North Louisiana). Further information regarding each of our programs is below:

- Eagle Ford Shale. The Eagle Ford Shale continues to provide the highest economic returns in our oil portfolio. We are currently running three rigs in this program.
- Wolfcamp Shale. In our Wolfcamp Shale program, we are focused on optimizing our drilling, completion and artificial lift systems. We are currently running one rig in this program.
- Altamont. In Altamont, we are gaining operational efficiencies as we develop this oil field. Our acreage in this area is largely held-by-production. We are currently running one rig in this program.
- Haynesville Shale. The Haynesville Shale is a natural gas program that is held-by-production. We are not currently running a rig in this area but did operate one rig from March through August of 2015.

We evaluate growth opportunities that are aligned with our core competencies and that are in areas that we believe can provide us a competitive advantage. Strategic acquisitions of leasehold acreage or acquisitions of producing assets can provide opportunities to achieve our long-term goals by leveraging existing expertise in our operating areas, balancing our exposure to regions, basins and commodities, helping us to achieve risk-adjusted returns competitive with those available within our existing drilling programs and by increasing our reserves. We continuously evaluate our asset portfolio and will evaluate opportunities to sell oil and natural gas properties if they no longer meet our long-term goals.

On September 4, 2015, we acquired approximately 12,000 net acres adjacent to our Eagle Ford Shale acreage for an adjusted cash purchase price of approximately $114 million. The acquisition is estimated to add an average of 500 Bbls/d of oil and 750 Boe/d to our annual estimated 2015 production and 164 future drilling locations. We are managing the development capital for the acquired properties within our current 2015 capital guidance.

Factors Influencing Our Profitability. Our profitability is dependent on the prices we receive for our oil and natural gas, the costs to explore, develop, and produce our oil and natural gas, and the volumes we are able to produce, among other factors. Our long-term profitability will be influenced primarily by:

- growing our proved reserve base and production volumes through the successful execution of our drilling programs or through acquisitions;
- finding and producing oil and natural gas at reasonable costs;
- managing cash costs; and
- managing commodity price risks on our oil and natural gas production.

In addition to these factors, our future profitability and performance will be affected by volatility in the financial and commodity markets, changes in the cost of drilling and oilfield services, operating and capital costs, and our debt level and related interest costs. Additionally, we may be impacted by weather events, regulatory issues or other third party actions outside of our control.

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As noted above, forward commodity prices play a significant role in determining impairments of proved or unproved property costs. Oil and natural gas prices are inherently volatile and decreased significantly during the latter part of 2014 and throughout 2015. For the quarter and nine months ended September 30, 2015, we did not record an impairment of our oil and natural gas properties, although the difference between the undiscounted cash flows and the carrying cost of those properties has narrowed significantly. However, further price declines and/or changes to our future capital, production rates, levels of proved reserves and development plans as a consequence of the lower price environment may result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant. For a further discussion of our proved and unproved property costs, see Part I, Item 1, Financial Statements, Note 6.

To the extent possible, we attempt to mitigate certain of our risks through actions such as entering into longer term contractual arrangements to control costs and by entering into derivative contracts to stabilize cash flows and reduce the financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our derivative contracts, our reported results of operations and financial position can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

Derivative Instruments. Our realized prices from the sale of our oil and natural gas are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our oil and natural gas, and (ii) other contractual pricing adjustments contained in the underlying sales contract. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we enter into financial derivative contracts to reduce the financial impact of unfavorable commodity price movements and locational price differences. Certain derivative contracts, usually short term in nature (less than one year), involve the receipt or payment of premiums. No cash premiums were received or paid for the nine months ended September 30, 2015. Cash premiums received for the nine months ended September 30, 2014, were approximately $1 million.

During the nine months ended September 30, 2015, we (i) settled commodity index hedges on approximately 92% of our oil production, 78% of our total liquids production and 87% of our natural gas production at average floor prices of $91.22 per barrel of oil and $4.26 per MMBtu, respectively and (ii) hedged basis risk on approximately 66% of our year-to-date Eagle Ford oil production and a portion of our Wolfcamp production. To the extent our oil and natural gas production is unhedged, either from a commodity index or locational price perspective, our financial results will be impacted from period to period as further described in Operating Revenues. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of September 30, 2015.

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	2015		2016		2017	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil						
Fixed Price Swaps						
WTI	4,653	$89.35	8,510	$80.03	4,015	$66.11
Brent	644	$100.01	—	$—	—	$—
LLS	—	$—	9,516	$80.51	—	$—
Ceilings	276	$100.00	—	$—	—	$—
Three Way Collars						
Ceiling - WTI	—	$—	—	$—	1,095	$75.13
Floors - WTI(2)	—	$—	—	$—	1,095	$65.00
Ceiling - Brent	276	$110.02	—	$—	—	$—
Floors - Brent(3)	276	$100.00	—	$—	—	$—
Basis Swaps						
LLS vs. WTI(4)	1,564	$3.88	2,013	$3.91	—	$—
LLS vs. Brent(5)	920	$(3.77)	2,196	$(4.99)	2,555	$(3.50)
Midland vs. Cushing(6)	276	$(0.65)	732	$(0.83)	1,460	$(0.68)
WTI - CM vs. TM(7)	920	$1.28	11,712	$0.31	—	$—
NYMEX Roll(8)	2,760	$(0.96)	8,230	$(0.86)	—	$—
Natural Gas						
Fixed Price Swaps	16	$4.26	7	$4.20	—	$—
Basis Swaps(9)						
CIG	1	$(0.25)	—	$—	—	$—
Waha	1	$(0.07)	—	$—	—	$—
Propane						
Fixed Price Swaps	12	$0.60	15	$0.55	—	$—

(1) Volumes presented are MBbls for oil, TBtu for natural gas and MMGal for propane. Prices presented are per Bbl of oil, MMBtu of natural gas and Gal for propane.
(2) If market prices settle at or below $55.00 in 2017, we will receive a “locked-in” cash settlement of the market price plus $10.00 per Bbl.
(3) If market prices settle at or below $85.00 in 2015, we will receive a “locked-in” cash settlement of the market price plus $15.00 per Bbl.
(4) EP Energy receives WTI plus the basis spread listed and pays LLS.
(5) EP Energy receives Brent plus the basis spread listed and pays LLS.
(6) EP Energy receives Cushing plus the basis spread listed and pays Midland.
(7) EP Energy receives WTI trade month (TM) plus the spread listed and pays WTI calendar month (CM).
(8) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").
(9) EP Energy receives the basis spread listed and pays CIG and Waha basis.

The following table reflects the volumes and prices associated with derivative contracts entered into between October 1, 2015 and October 27, 2015, which are not reflected in the table above.

	2017	
	Volumes(1)	Average

		Price[1]
Oil		
Basis Swaps		
LLS vs. Brent[2]	365	$(2.80)

(1) Volumes presented are MBbls. Prices presented are per Bbl.
(2) EP Energy receives Brent plus the basis spread listed and pays LLS.

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Summary of Liquidity and Capital Resources. As of September 30, 2015, we had available liquidity, including existing cash, of approximately $1.6 billion. We believe we have sufficient liquidity for the remainder of 2015 and 2016 from our cash flows from operations (including our hedging program, which provides significant price protection to our near-term revenues and cash flows), combined with the availability under our $2.75 billion RBL Facility and available cash, to fund our obligations, projected working capital requirements and capital spending plans. Additionally, with the extension of our $2.75 billion RBL Facility maturity date to 2019, the earliest maturity date of our remaining term debt obligations is in 2018. See “Liquidity and Capital Resources” for more information.

Outlook for 2015. For the full year 2015, we expect the following:

- Capital expenditures (not including acquisition capital) of approximately $1.2 billion to $1.25 billion, allocated as follows: $770 million to Eagle Ford, $245 million to Wolfcamp, $150 million to Altamont and $60 million to Haynesville.

- Well completions between 165 and 195.

- Average daily production volumes for the year of approximately 102.25 MBoe/d to 110.25 MBoe/d, including average daily oil production volumes of approximately 60.5 MBbls/d to 63.5 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $10.25 to $11.25 per Boe, and transportation costs of approximately $2.60 to $2.90 per Boe.

- Per unit depreciation, depletion and amortization rate for the year of approximately $24.50 to $26.50 per Boe.

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Production Volumes and Drilling Summary

Production Volumes. Below is an analysis of our production volumes for the nine months ended September 30:

	2015	2014
United States (MBoe/d)		
Eagle Ford Shale	58.9	49.7
Wolfcamp Shale	19.4	14.6
Altamont	17.4	15.1
Haynesville Shale	12.9	16.6
Other	0.1	0.2
Total	108.7	96.2
Oil (MBbls/d)	61.8	53.0
Natural Gas (MMcf/d)	196	193
NGLs (MBbls/d)	14.1	11.0

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes and oil production increased 9.2 MBoe/d (19%) and 6.0 MBbls/d (18%), respectively, for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 due to the success of our drilling program in the area. During the nine months ended September 30, 2015, we completed 104 additional operated wells in the Eagle Ford, and we had a total of 551 net operated wells (including 83 wells acquired in the third quarter) as of September 30, 2015. A majority of our acreage (including our recent acquisition) is located in the core of the oil window, primarily in LaSalle county.

- Wolfcamp Shale—Our Wolfcamp Shale equivalent volumes increased 4.8 MBoe/d (33%) for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 as we continue to progress in the development of the program. Wolfcamp produced an average of 9.3 MBbls/d of oil during the nine months ended September 30, 2015, and we completed 35 additional operated wells, for a total of 236 net operated wells as of September 30, 2015.

- Altamont—Our Altamont equivalent volumes increased 2.3 MBoe/d (15%) for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014. Altamont produced an average of 12.7 MBbls/d of oil during the nine months ended September 30, 2015, and we completed 28 additional operated oil wells for a total of 377 net operated wells at September 30, 2015.

- Haynesville Shale—Our Haynesville Shale equivalent volumes decreased 3.7 MMcf/d (22%) for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014, due to natural production declines. In 2015, we allocated capital to this program to test the impact of current completion and refracking techniques on well performance and financial returns. As of September 30, 2015, we completed 2 additional operated wells for a total of 101 net operated wells in the Haynesville Shale, and our total natural gas production for the nine months ended September 30, 2015 was approximately 78 MMcf/d.

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Results of Operations

The information in the table below provides a summary of our generally accepted accounting principles (GAAP) financial results.

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues				
Oil	$245	$474	$781	$1,341
Natural gas	58	67	152	220
NGLs	16	31	44	88
Total physical sales	319	572	977	1,649
Financial derivatives	434	381	458	(44)
Total operating revenues	753	953	1,435	1,605
Operating expenses				
Natural gas purchases	9	8	24	16
Transportation costs	30	22	82	71
Lease operating expense	45	48	139	142
General and administrative	32	33	114	208
Depreciation, depletion and amortization	260	228	737	634
Impairment charges	—	1	—	1
Exploration and other expense	2	5	14	18
Taxes, other than income taxes	20	35	65	102
Total operating expenses	398	380	1,175	1,192
Operating income	355	573	260	413
Loss on extinguishment of debt	—	—	(41)	(17)
Interest expense	(84)	(76)	(249)	(235)
Income (loss) from continuing operations before income taxes	271	497	(30)	161
Income tax expense (benefit)	95	191	(13)	67
Income (loss) from continuing operations	176	306	(17)	94
(Loss) income from discontinued operations, net of tax	—	(1)	—	3
Net income (loss)	$176	$305	$(17)	$97

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters and nine months ended September 30, 2015 and 2014. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Operating revenues:				
Oil	$245	$474	$781	$1,341
Natural gas	58	67	152	220
NGLs	16	31	44	88
Total physical sales	319	572	977	1,649
Financial derivatives	434	381	458	(44)
Total operating revenues	$753	$953	$1,435	$1,605
Volumes:				
Oil (MBbls)	5,717	5,260	16,885	14,481
Natural gas (MMcf)	19,904	17,572	53,569	52,700
NGLs (MBbls)	1,499	1,098	3,858	2,992
Equivalent volumes (MBoe)	10,533	9,286	29,671	26,256
Total MBoe/d	114.5	100.9	108.7	96.2
Prices per unit(1):				
Oil				
Average realized price on physical sales ($/Bbl)(2)	$42.90	$90.19	$46.25	$92.61
Average realized price, including financial derivatives ($/Bbl)(2)(3)	$83.56	$89.65	$80.41	$90.49
Natural gas				
Average realized price on physical sales ($/Mcf)(2)	$2.47	$3.32	$2.40	$3.87
Average realized price, including financial derivatives ($/Mcf)(3)	$3.65	$3.27	$3.67	$3.30
NGLs				
Average realized price on physical sales ($/Bbl)	$10.62	$28.56	$11.44	$29.39
Average realized price, including financial derivatives ($/Bbl)(3)	$12.10	$29.24	$12.48	$29.57

(1) Natural gas prices for the quarter and nine months ended September 30, 2015 are calculated including a reduction of $9 million and $24 million, respectively, for natural gas purchases associated with managing our physical sales. Natural gas prices for the quarter and nine months ended September 30, 2014 are calculated including a reduction of $8 million and $16 million, respectively, for natural gas purchases associated with managing our physical sales.

(2) Changes in realized oil and natural gas prices reflect the effects of unfavorable unhedged locational or basis differentials, unhedged volumes and contractual deductions between the commodity price index and the actual price at which we sold our oil and natural gas.

(3) The quarters ended September 30, 2015 and 2014, include approximately $233 million of cash received and $3 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $23

million of cash received and $1 million of cash paid, respectively, for the settlement of natural gas financial derivatives. The nine months ended September 30, 2015 and 2014, include approximately $577 million of cash received and $31 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $68 million of cash received and $30 million of cash paid, respectively, for the settlement of natural gas financial derivatives. For the quarter and nine months ended September 30, 2015, we received approximately $2 million and $4 million, respectively, for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the quarter and nine months ended September 30, 2015. For the quarter and nine months ended September 30, 2014, we received approximately $1 million and less than $1 million for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the quarter ended September 30, 2014. Cash premiums received for the nine months ended September 30, 2014 were approximately $1 million.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter and nine months ended September 30, 2015, physical sales decreased by $253 million (44%) and $672 million (41%), respectively, compared to the same periods in 2014. Physical sales have decreased due to lower commodity prices partially offset by oil and gas volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. The table below displays the price and volume variances on our physical sales when comparing the quarters and nine months ended September 30, 2015 and 2014.

	Quarter ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2014 sales	$474	$67	$31	$572
Change due to prices	(269)	(18)	(27)	(314)
Change due to volumes	40	9	12	61
September 30, 2015 sales	$245	$58	$16	$319
	Nine months ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2014 sales	$1,341	$220	$88	$1,649
Change due to prices	(783)	(71)	(69)	(923)
Change due to volumes	223	3	25	251
September 30, 2015 sales	$781	$152	$44	$977

Oil sales for the quarter and nine months ended September 30, 2015 compared to the same periods in 2014 decreased by $229 million (48%) and $560 million (42%), respectively, due primarily to lower oil prices partially offset by oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. For the quarter and nine months ended September 30, 2015 compared to the same periods in 2014, Eagle Ford oil production increased by 11% (4.0 MBbls/d) and 18% (6.0 MBbls/d), respectively, Wolfcamp oil production increased by 1% (0.1 MBbls/d) and 15% (1.2 MBbls/d), respectively, and Altamont oil production increased by 8% (0.9 MBbls/d) and 14% (1.6 MBbls/d), respectively.

Natural gas sales decreased for the quarter and nine months ended September 30, 2015 compared to the same periods in 2014 primarily due to lower natural gas prices and a decrease in volumes due to natural gas production declines in the Haynesville Shale, offset by natural gas volume growth in Wolfcamp, Eagle Ford and Altamont.

Our oil and natural gas is typically sold at index prices (WTI, LLS and Henry Hub) or posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of contractual deducts, differentials from the index to the delivery point and/or discounts for quality or grade. Generally as the index price of our commodities increase, deducts and differentials widen and can further widen for temporary or permanent changes in supply or demand, capacity constraints or the build out of infrastructure in developing areas.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In Wolfcamp, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. In Altamont, market pricing of our oil is based upon both Salt Lake City refinery postings and rail economics, which reflect transportation and handling costs associated with moving wax crude by truck and/or rail to end users. Across all regions, natural gas realized pricing is influenced by factors such as excess royalties paid on flared gas and the percentage of proceeds retained under processing contracts, in addition to the normal seasonal supply and demand influences and those factors discussed above. The table below displays the weighted average differentials and deducts on our oil and natural gas sales on an average NYMEX price.

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	Quarters ended September 30,			
	2015		2014	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(4.22)	$(0.33)	$(7.18)	$(0.60)
NYMEX	$46.43	$2.77	$97.17	$4.06

	Nine months ended September 30,			
	2015		2014	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(5.10)	$(0.41)	$(6.98)	$(0.61)
NYMEX	$51.00	$2.80	$99.61	$4.55

The smaller oil differentials and deducts in the quarter and nine months ended September 30, 2015 were primarily a result of an increase in LLS and Midland/Cushing relative to NYMEX in Eagle Ford and Wolfcamp, respectively, improved physical sales contract pricing in both Eagle Ford and Wolfcamp, and improved refinery postings in Altamont. The smaller natural gas differentials and deducts in the quarter and nine months ended September 30, 2015 were primarily a result of improved locational basis differentials in the Haynesville area and lower excess royalties paid on flared gas.

NGLs sales decreased for the quarter and nine months ended September 30, 2015 compared to the same periods in 2014. Average realized prices declined in 2015 compared to the same period in 2014, due in part to lower pricing on all liquids components. NGLs volume increased as a result of our Eagle Ford and Wolfcamp drilling programs. For the quarter and nine months ended September 30, 2015 compared to the same periods in 2014, Eagle Ford NGLs volumes increased by 38% (3.0 MBbls/d) and 22% (1.7 MBbls/d), respectively, and Wolfcamp NGLs volumes increased by 34% (1.4 MBbls/d) and 47% (1.5 MBbls/d), respectively.

As of September 30, 2015, the NYMEX spot price of a barrel of oil was $45.09 versus the NYMEX spot price of a MMBtu of natural gas of $2.52, or a ratio of 18 to 1. Despite declines in oil prices, the value difference between these commodities is such that we will continue to allocate capital to our oil-based programs. Growth in our overall oil sales (including the impact of financial derivatives) will largely be impacted by our ability to grow oil volumes and will also be impacted by commodity pricing to the extent we are unhedged and by the location of our production and the nature of our sales contracts. Based on our hedges in place as of September 30, 2015, we are approximately 97% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.11 per barrel for the remainder of 2015. See "Our Business" for further information on our derivative instruments.

Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the quarter ended September 30, 2015, we recorded $434 million of derivative gains compared to derivative gains of $381 million during the quarter ended September 30, 2014. For the nine months ended September 30, 2015, we recorded $458 million of derivative gains compared to derivative losses of $44 million during the nine months ended September 30, 2014.

Operating Expenses

Transportation costs. Transportation costs for the quarter and nine months ended September 30, 2015 were $30 million and $82 million, respectively, compared to $22 million and $71 million for the same periods in 2014. Total transportation costs increased for the quarter and nine months ended September 30, 2015 primarily due to gas transportation costs associated with Eagle Ford and Wolfcamp as a result of our production growth and new contracts in these areas.

Lease operating expense. Lease operating expense for the quarter and nine months ended September 30, 2015 was $45 million and $139 million, respectively, compared to $48 million and $142 million for the same periods in 2014.

For the quarter and nine months ended September 30, 2015, we incurred a decrease in lease operating expense in Eagle Ford of approximately $1 million and $8 million, respectively, due to lower chemical costs due to changing the method (amine unit vs. chemicals) in which we treated our gas, lower power costs due to releasing rental generators and lower disposal and labor costs. In Altamont, we incurred a decrease of $3 million and $4 million in the quarter and nine months ended September 30, 2015 due to lower chemical costs and lower maintenance and repair costs. These decreases in lease operating expense in Eagle Ford and Altamont were partially offset by higher maintenance, repair and compression costs in Wolfcamp associated with growing

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production volumes in this area of approximately $1 million and $9 million, respectively, for the quarter and nine months ended September 30, 2015.

General and administrative expenses. General and administrative expenses for the quarter and nine months ended September 30, 2015 were $32 million and $114 million, respectively, compared to $33 million and $208 million for the same periods in 2014. In the first quarter of 2014, we paid Sponsor-related fees of approximately $90 million under agreements that terminated with the completion of our 2014 initial public offering. Additionally, for the quarter and nine months ended September 30, 2015 we incurred lower payroll, benefits and administrative costs of $4 million and $18 million compared to the same periods in 2014 from lower headcount. Partially offsetting these reductions in 2015 were an $11 million insurance settlement received in the third quarter of 2014 and higher transition and restructuring costs of $6 million during the nine months ended 2015 compared to 2014, among other items.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the quarter and nine months ended September 30, 2015 were $260 million and $737 million, respectively, compared to $228 million and $634 million for the same periods in 2014. Our depreciation, depletion and amortization costs increased in 2015 compared to the same periods in 2014 due to an increase in production volumes from the ongoing development of higher cost oil programs (e.g., Eagle Ford and Wolfcamp) and slightly higher depletion rates. Our average depreciation, depletion and amortization costs per unit for the quarters and nine months ended September 30 were:

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Depreciation, depletion and amortization ($/Boe)	$24.69	$24.56	$24.83	$24.14

Exploration and other expense. For the quarter and nine months ended September 30, 2015, we recorded $2 million and $14 million of exploration expense compared to $5 million and $18 million for the same periods in 2014. Included in exploration expense for the quarter and nine months ended September 30, 2015 are $1 million and $9 million, respectively, of amortization of unproved leasehold costs compared to $4 million and $15 million for the same periods in 2014. In addition, in the nine months ended September 30, 2015, we recorded approximately $2 million as other expense in conjunction with the early termination of a contract for drilling rigs during the first quarter of 2015.

Taxes, other than income taxes. Taxes, other than income taxes for the quarter and nine months ended September 30, 2015 were $20 million and $65 million, respectively, compared to $35 million and $102 million for the same periods in 2014. Production taxes decreased in 2015 compared to the same periods in 2014 due to the significant impact on severance taxes of lower commodity prices.

Cash Operating Costs and Adjusted Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas. Cash operating costs is a non-GAAP measure calculated on a per Boe basis and includes total operating expenses less depreciation, depletion and amortization expense, transportation costs, exploration expense, natural gas purchases, impairment charges and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which terminated on January 23, 2014), and the non-cash portion of compensation expense (which represents compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans). We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the quarters and nine months ended September 30:

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	Quarters ended September 30,			
	2015		2014	
	Total	Per Unit[1]	Total	Per Unit[1]
	(in millions, except per unit costs)			
Total continuing operating expenses	$398	$37.78	$380	$40.94
Depreciation, depletion and amortization	(260)	(24.69)	(228)	(24.56)
Transportation costs	(30)	(2.87)	(22)	(2.42)
Exploration expense	(2)	(0.16)	(5)	(0.54)
Natural gas purchases	(9)	(0.90)	(8)	(0.92)
Impairment charges	—	—	(1)	(0.07)
Total continuing cash operating costs	97	9.16	116	12.43
Transition/restructuring costs, non-cash portion of compensation expense and other[2]	(5)	(0.44)	3	0.42
Total adjusted cash operating costs and adjusted per-unit cash operating costs	$92	$8.72	$119	$12.85
Total equivalent volumes (MBoe)	10,533		9,286	

	Nine months ended September 30,			
	2015		2014	
	Total	Per Unit[1]	Total	Per Unit[1]
	(in millions, except per unit costs)			
Total continuing operating expenses	$1,175	$39.59	$1,192	$45.40
Depreciation, depletion and amortization	(737)	(24.83)	(634)	(24.14)
Transportation costs	(82)	(2.78)	(71)	(2.72)
Exploration expense	(12)	(0.41)	(18)	(0.68)
Natural gas purchases	(24)	(0.80)	(16)	(0.62)
Impairment charges	—	—	(1)	(0.02)
Total continuing cash operating costs	320	10.77	452	17.22
Transition/restructuring costs, non-cash portion of compensation expense and other[2]	(15)	(0.52)	(92)	(3.49)
Total adjusted cash operating costs and adjusted per-unit cash operating costs	$305	$10.25	$360	$13.73
Total equivalent volumes (MBoe)	29,671		26,256	

(1) Per unit costs are based on actual total amounts rather than the rounded totals presented.

(2) For the quarter ended September 30, 2015, amount includes approximately $5 million of non-cash compensation expense, adjusted for cash payments made of less than $1 million. For the nine months ended September 30, 2015, amount includes approximately $8 million of transition and severance costs related to restructuring and $8 million of non-cash compensation expense, adjusted for cash payments made of approximately $8 million. For the quarter ended September 30, 2014, amount includes $11 million of cash received from an insurance settlement, $5 million of acquisition costs and $2 million of non-cash compensation expense, adjusted for cash payments made of less than $1 million. For the nine months ended September 30, 2014, amount includes $90 million of transaction, management and other fees paid to the Sponsors, $11 million of cash received from an insurance settlement, $5

million of acquisition costs and $6 million of non-cash compensation expense, adjusted for cash payments made of approximately $13 million, as well as transition and severance costs related to restructuring. The non-cash portion of compensation expense represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans.

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The table below displays the average cash operating costs and adjusted cash operating costs per equivalent unit:

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Average cash operating costs ($/Boe)				
Lease operating expenses	$4.25	$5.12	$4.67	$5.41
Production taxes(1)	1.81	3.60	1.99	3.64
General and administrative expenses(2)	3.02	3.52	3.84	7.93
Taxes, other than production and income taxes	0.08	0.19	0.20	0.24
Other expenses(3)	—	—	0.07	—
Total continuing cash operating costs	9.16	12.43	10.77	17.22
Transition/restructuring costs, non-cash portion of compensation expense and other(2)	(0.44)	0.42	(0.52)	(3.49)
Total adjusted cash operating costs	$8.72	$12.85	$10.25	$13.73

(1) Production taxes include ad valorem and severance taxes which decreased during the quarter and nine months ended September 30, 2015 due primarily to lower commodity prices.

(2) For additional detail of adjusted items included in general and administrative expenses, refer to the reconciliation of cash operating costs and adjusted cash operating costs above.

(3) Includes early rig termination fees of $2 million incurred during the first quarter of 2015.

Other Income Statement Items.

Loss on extinguishment of debt. For the nine months ended September 30, 2015, we recorded $41 million ($12 million of which was non-cash) in losses on extinguishment of debt in conjunction with the early repayment and retirement of our $750 million senior secured notes due 2019. For the nine months ended September 30, 2014, we recorded $17 million in losses on extinguishment of debt for the portion of deferred financing costs written off in conjunction with the repayment and retirement of the PIK toggle note.

Interest expense. Interest expense increased for the quarter and nine months ended September 30, 2015 compared to the same periods in 2014 due to higher interest expense related to our RBL Facility and changes in the fair market value of our interest rate derivative instruments. The increase in interest expense for the nine months ended September 30, 2015 compared to 2014 was partially offset by a decrease due to the retirement of the PIK toggle note in early 2014 and lower amortization of debt issuance costs.

(Loss) income from discontinued operations. Our (loss) income from discontinued operations for the quarter and nine months ended September 30, 2014 includes the financial results of assets classified as discontinued operations and gains (losses) recorded on the sale of these assets in 2014.

Supplemental Non-GAAP Measures

We use the non-GAAP measures “EBITDAX” and “Adjusted EBITDAX” as supplemental measures. We believe these supplemental measures provide meaningful information to our investors. We define EBITDAX as income (loss) from continuing operations plus interest and debt expense, income taxes, depreciation, depletion and amortization and exploration expense. Adjusted EBITDAX is defined as EBITDAX, adjusted as applicable in the relevant period for the net change in the fair value of derivatives (mark-to-market effects of financial derivatives, net of settlements and cash premiums related to these derivatives), the non-cash portion of compensation expense (which represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans), transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which ended in 2014), losses on extinguishment of debt and impairment charges.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business, (iii) for evaluating our performance relative to our peers, (iv) to measure our liquidity (before cash capital requirements and working capital needs) and (v) to provide supplemental information about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDAX and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), income (loss) from continuing operations, operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with GAAP.

Below is a reconciliation of our EBITDAX and Adjusted EBITDAX to our consolidated net income (loss):

	Quarters ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(in millions)			
Net income (loss)	$176	$305	$(17)	$97
Loss (income) from discontinued operations, net of tax	—	1	—	(3)
Income (loss) from continuing operations	176	306	(17)	94
Income tax expense (benefit)	95	191	(13)	67
Interest expense, net of capitalized interest	84	76	249	235
Depreciation, depletion and amortization	260	228	737	634
Exploration expense	2	5	12	18
EBITDAX	617	806	968	1,048
Mark-to-market on financial derivatives(1)	(434)	(381)	(458)	44
Settlements and cash premiums on financial derivatives(2)	258	(3)	649	(60)
Non-cash portion of compensation expense(3)	5	2	8	6
Transition, restructuring and other costs(4)	—	(6)	8	(5)
Fees paid to Sponsors(5)	—	—	—	90
Loss on extinguishment of debt(6)	—	—	41	17
Impairment charges	—	1	—	1
Adjusted EBITDAX	$446	$419	$1,216	$1,141

(1) Represents the income statement impact of financial derivatives.

(2) Represents actual settlements related to financial derivatives, including cash premiums. No cash premiums were received or paid for the quarter and nine months ended September 30, 2015. No cash premiums were received or paid for the quarter ended September 30, 2014. For the nine months ended September 30, 2014, we received approximately $1 million of cash premiums.

(3) For the quarter and nine months ended September 30, 2015, cash payments were less than $1 million and approximately $8 million, respectively. For the quarter and nine months ended September 30, 2014, cash payments were less than $1 million and approximately $13 million, respectively.

(4) Reflects transition and severance costs related to restructuring for the quarter and nine months ended September 30, 2015. Reflects an $11 million insurance settlement and $5 million of acquisition costs in the third quarter of 2014 as well as transition and severance costs related to restructuring activities.

(5) Represents transaction, management and other fees paid to the Sponsors in 2014.

(6) Represents the loss on extinguishment of debt recorded related to the repayment in May 2015 of our 2019 $750 million senior secured note and the retirement of the PIK toggle note in 2014.

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part I, Item 1, Financial Statements, Note 8.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility. Our primary uses of cash are capital expenditures, debt service requirements including interest, and working capital requirements. As of September 30, 2015, our available liquidity was approximately $1.6 billion. In April 2015, we completed our semi-annual redetermination of our RBL Facility, reaffirming the borrowing base at $2.75 billion and extending the maturity date from May 2017 to May 2019, provided that our 2018 and 2019 secured term loans are retired or refinanced six months prior to their maturity. Our next redetermination date is in November 2015. Downward revisions of our oil and natural gas reserves due to declines in commodity prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base which could negatively impact our borrowing capacity under the RBL Facility in the future. Additionally, during the second quarter of 2015, we issued $800 million of senior unsecured notes due in June 2023. We used a substantial portion of the proceeds from the offering to purchase for cash all of the $750 million of senior secured notes due 2019.

We believe we have sufficient liquidity from (i) our cash flows from operations (including our hedging program), (ii) availability under the RBL Facility and (iii) available cash, to fund our capital program, current obligations and projected working capital requirements for the remainder of 2015 and 2016. Additionally, with the extension of our $2.75 billion RBL Facility maturity date to 2019, the earliest maturity date of our remaining term debt obligations is in 2018. Furthermore, despite the declines in oil prices, we believe our oil and natural gas derivative contracts provide significant commodity price protection on a substantial portion of our anticipated production for 2015 and 2016. These derivative contracts, which are primarily fixed price swaps, have been effective in mitigating the impact of price declines to our near-term revenues and also provide greater cash flow certainty. Based on our hedges in place as of September 30, 2015, we are approximately 97% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.11 per barrel for the remainder of 2015. See "Our Business" for further information on our derivative instruments.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all on the occurrence of certain events, such as a change of control, or (iii) obtain additional capital if required on acceptable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control.

The extreme ongoing volatility in the energy industry and commodity prices will likely continue to impact our outlook. Our plans are designed to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund our capital programs in our core drilling programs, (ii) meeting our debt maturities, and (iii) managing our balance sheet. We continue to implement various cost saving measures to reduce our capital, operating, as well as general and administrative costs including obtaining supply chain management savings with regard to capital expenditures and cash operating costs, renegotiating contracts with contractors, suppliers and service providers, and deferring and eliminating various discretionary costs. Additionally, we will continue to be opportunistic in terms of managing our liquidity when prudent to meet our long-term capital needs, or in terms of managing our balance sheet. We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and achieving cost efficiency. For example, we could elect to repurchase a portion of our outstanding debt in the future for cash through open market repurchases, in the event of favorable market conditions and a number of other factors, although there is no assurance we will do so.

To the extent commodity prices remain low or further decline or we experience major disruptions in the financial markets impacting our longer-term access to capital for future growth projects as well as the cost of such capital, it is possible additional adjustments to our plan and outlook may be required which could impact our financial and operating performance. These adjustments could involve pursuing various alternatives, including reductions to our planned capital program, additional debt or equity financings, seeking additional partners or selling assets.

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Capital Expenditures. For the full year 2015, we expect our capital expenditures will be approximately $1.2 billion to $1.25 billion, exclusive of acquisition capital. Our capital expenditures and average drilling rigs by area for the nine months ended September 30, 2015 were:

	Capital Expenditures(1) (in millions)	Average Drilling Rigs
Eagle Ford Shale(2)	$756	3.8
Wolfcamp Shale	216	1.2
Altamont	127	1.7
Haynesville Shale	47	0.5
Total	$1,146	7.2

(1) Represents accrual-based capital expenditures.
(2) Includes approximately $115 million of acquisition capital.

Long-Term Debt. As of September 30, 2015, our long-term debt is approximately $4.9 billion, comprised of $3.2 billion in senior notes due in 2020, 2022 and 2023, $646 million in senior secured term loans with maturity dates in 2018 and 2019, and $1.1 billion outstanding under the RBL Facility expiring in 2019. We continually monitor the debt capital markets and our capital structure and will make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, and achieving cost efficiency. For additional details on our long-term debt, including restrictive covenants under our debt agreements, see Part I, Item 1, Financial Statements, Note 7.

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Overview of Cash Flow Activities. Our cash flows from operations (which include both continuing and discontinued activities) are summarized as follows (in millions):

	Nine months ended September 30,	
	2015	2014
Cash Flow from Operations		
Operating activities		
Net (loss) income	$(17)	$97
Impairment charges	—	19
Other income adjustments	802	763
Changes in assets and liabilities	254	27
Total cash flow from operations	$1,039	$906
Other Cash Inflows		
Investing activities		
Proceeds from the sale of assets, net of cash transferred	$—	$126
	$—	$126
Financing activities		
Proceeds from issuance of long-term debt	1,777	1,835
Proceeds from issuance of stock	—	669
	1,777	2,504
Total cash inflows	$1,777	$2,630
Cash Outflows		
Investing activities		
Capital expenditures	$1,203	$1,521
Cash paid for acquisitions, net of cash acquired	114	154
	$1,317	$1,675
Financing activities		
Repayments of long-term debt	1,473	1,895
Debt issuance costs	19	—
Other	1	—
	1,493	1,895
Total cash outflows	$2,810	$3,570
Net change in cash and cash equivalents	$6	$(34)

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Item 3. Qualitative and Quantitative Disclosures About Market Risk

This information updates, and should be read in conjunction with the information disclosed in our 2014 Annual Report on Form 10-K, in addition to the information presented in Items 1 and 2 of Part I of this Quarterly Report on Form 10-Q. There have been no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2014 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at September 30, 2015:

		Oil, Natural Gas and NGL Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(in millions)				
Price impact[1]	$854	$710	$(144)	$998	$144

		Oil, Natural Gas and NGL Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(in millions)				
Discount rate[2]	$854	$849	$(5)	$859	$5
Credit rate[3]	$854	$845	$(9)	$858	$4

(1) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from changes in oil, natural gas and NGL prices.

(2) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in the discount rates we used to determine the fair value of our derivatives.

(3) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in credit risk of our counterparties.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2015, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect 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 our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of September 30, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in EP Energy Corporation's internal control over financial reporting during the first nine months of 2015 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8.

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in the 2014 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreement and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

SIGNATURES

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.

	EP ENERGY CORPORATION
Date: October 30, 2015	/s/ Dane E. Whitehead Dane E. Whitehead Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: October 30, 2015	/s/ Francis C. Olmsted III Francis C. Olmsted III Vice President and Controller (Principal Accounting Officer)

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EP ENERGY CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed as part of this Report. Exhibits filed with this Report are designated by "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*12.1	Ratio of Earnings to Fixed Charges
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Schema Document.
*101.CAL	XBRL Calculation Linkbase Document.
*101.DEF	XBRL Definition Linkbase Document.
*101.LAB	XBRL Labels Linkbase Document.
*101.PRE	XBRL Presentation Linkbase Document.