CALLON PETROLEUM CO
Form 10-Q
November 06, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM
10-Q

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

For The Quarterly Period Ended September 30, 2014

OR

TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	64-0844345
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
200 North Canal Street	
Natchez, Mississippi	
(Address of Principal Executive Offices)	39120 (Zip Code)

601-442-1601

(Registrant’s Telephone Number, Including Area Code)

Not Applicable

(Former Name, Former Address and Former Fiscal Year, If Changed Since Last Report)

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

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

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

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

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

As of October 31, 2014, 55,225,288 shares of the Registrant's common stock, par value $0.01 per share, were outstanding.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

- ARO: asset retirement obligation.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- BOE: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- BBtu: billion Btu.
- BOE/d: BOE per day.
- Btu: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- LIBOR: London Interbank Offered Rate.
- LOE: lease operating expense.
- MBbls: thousand barrels of oil.
- MBOE: thousand BOE.
- Mcf: thousand cubic feet of natural gas.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- NGL or NGLs: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- NYMEX: New York Mercantile Exchange.
- Oil: includes crude oil and condensate.
- SEC: United States Securities and Exchange Commission.
- GAAP: Generally Accepted Accounting Principles in the United States.

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

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Part I. Financial Information

Item I. Financial Statements

Callon Petroleum Company

Consolidated Balance Sheets

(in thousands, except par and per share values and share data)

	September 30, 2014 Unaudited	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,193	$ 3,012
Accounts receivable	27,923	20,586
Deferred tax asset	3,321	3,843
Fair value of derivatives	4,842	60
Other current assets	1,260	2,063
Total current assets	44,539	29,564
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	1,894,803	1,701,577
Less accumulated depreciation, depletion and amortization	(1,460,271)	(1,420,612)
Net oil and natural gas properties	434,532	280,965
Unevaluated properties	40,445	43,222
Total oil and natural gas properties	474,977	324,187
Other property and equipment, net	7,033	7,255
Restricted investments	3,802	3,806
Deferred tax asset	45,952	57,765
Acquisition deposit	10,629	—
Other assets, net	5,294	1,376
Total assets	$ 592,226	$ 423,953
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 50,491	$ 53,464
Market-based restricted stock unit awards	5,668	4,173
Asset retirement obligations	5,138	4,120
Fair value of derivatives	465	1,036
Total current liabilities	61,762	62,793
13% senior notes:		
Principal outstanding	—	48,481
Deferred credit, net of accumulated amortization of $0 and $26,239, respectively	—	5,267
Total 13% senior notes	—	53,748
Senior secured revolving credit facility	20,000	22,000
Secured second lien term loan	82,500	—

Asset retirement obligations	1,281	2,612
Market-based restricted stock unit awards	9,841	3,409
Other long-term liabilities	1,091	297
Total liabilities	176,475	144,859
Stockholders’ equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 1,578,948 and 1,578,948 shares outstanding, respectively	16	16
Common stock, $0.01 par value, 110,000,000 and 60,000,000 shares authorized; 55,218,827 and 40,345,456 shares outstanding, respectively	552	404
Capital in excess of par value	525,166	401,540
Accumulated deficit	(109,983)	(122,866)
Total stockholders’ equity	415,751	279,094
Total liabilities and stockholders’ equity	$ 592,226	$ 423,953

The accompanying notes are an integral part of these consolidated financial statements.

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Callon Petroleum Company

Consolidated Statements of Operations

(Unaudited; in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Operating revenues:				
Oil sales	$ 36,346	$ 27,014	$ 104,965	$ 65,615
Natural gas sales	3,311	3,783	8,479	10,483
Total operating revenues	39,657	30,797	113,444	76,098
Operating expenses:				
Lease operating expenses	6,270	5,270	14,863	16,412
Production taxes	2,247	991	6,429	2,217
Depreciation, depletion and amortization	16,115	11,907	38,635	33,603
General and administrative	3,261	5,826	23,707	14,110
Accretion expense	202	458	603	1,556
Gain on sale of other property and equipment	—	—	(1,080)	—
Total operating expenses	28,095	24,452	83,157	67,898
Income from operations	11,562	6,345	30,287	8,200
Other (income) expenses:				
Interest expense	2,205	1,417	5,007	4,469
Gain on early extinguishment of debt	—	—	(3,205)	—
(Gain) loss on derivative contracts	(9,944)	3,686	(2,746)	2,123
Other (income) expense	(61)	(279)	(203)	(368)
Total other (income) expenses	(7,800)	4,824	(1,147)	6,224
Income before income taxes	19,362	1,521	31,434	1,976
Income tax expense	7,161	456	12,630	950
Income before equity in earnings of Medusa Spar LLC	12,201	1,065	18,804	1,026
Equity from Medusa Spar LLC	—	17	—	14
Net income	12,201	1,082	18,804	1,040
Preferred stock dividends	(1,974)	(1,974)	(5,921)	(2,654)
Income (loss) available to common stockholders	$ 10,227	$ (892)	$ 12,883	$ (1,614)
Income (loss) per common share:				
Basic	$ 0.24	$ (0.02)	$ 0.31	$ (0.04)
Diluted	$ 0.23	$ (0.02)	$ 0.30	$ (0.04)
Shares used in computing income (loss) per common share:				
Basic	43,187	40,321	41,370	40,064
Diluted	44,211	40,321	42,510	40,064

The accompanying notes are an integral part of these consolidated financial statements.

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Callon Petroleum Company

Consolidated Statements of Cash Flows

(Unaudited; in thousands)

	Nine Months Ended September 30,	
	2014	2013
Cash flows from operating activities:		
Net income	$ 18,804	$ 1,040
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	39,493	34,668
Accretion expense	603	1,556
Amortization of non-cash debt related items	494	348
Amortization of deferred credit	(433)	(2,448)
Equity in earnings of Medusa Spar LLC	—	(14)
Deferred income tax expense	12,630	950
Net loss (gain) on derivatives, net of settlements	(5,728)	2,929
Gain on sale of other property and equipment	(1,080)	—
Non-cash gain on early debt extinguishment	(3,205)	—
Non-cash expense related to equity share-based awards	432	1,335
Change in the fair value of liability share-based awards	6,571	1,076
Payments to settle asset retirement obligations	(3,283)	(701)
Changes in current assets and liabilities:		
Accounts receivable	(8,016)	(3,455)
Other current assets	802	(236)
Current liabilities	3,449	1,969
Payments to settle vested liability share-based awards	(3,469)	(239)
Change in other long-term liabilities	—	(258)
Change in other assets, net	(367)	(3,306)
Net cash provided by operating activities	57,697	35,214
Cash flows from investing activities:		
Capital expenditures	(188,793)	(101,067)
Acquisition	—	(11,000)
Deposit on acquisition	(10,629)	—
Proceeds from sales of mineral interest and equipment	1,991	1,389
Distribution from Medusa Spar LLC	—	813
Net cash used in investing activities	(197,431)	(109,865)
Cash flows from financing activities:		
Borrowings on debt	200,000	48,000
Payment of deferred financing costs	(3,068)	—
Payments on debt	(169,610)	(41,000)
Issuance of preferred stock	—	70,035

Issuance of common stock	122,514	—
Payment of preferred stock dividends	(5,921)	(2,654)
Net cash provided by financing activities	143,915	74,381
Net change in cash and cash equivalents	4,181	(270)
Balance, beginning of period	3,012	1,139
Balance, end of period	$ 7,193	$ 869

The accompanying notes are an integral part of these consolidated financial statements.

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Callon Petroleum Company

Notes to the Consolidated Financial Statements

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial

statements are presented in thousands, except for per share and per unit data)

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Description of Business and Basis of Presentation

Description of business

Callon Petroleum Company is an independent oil and natural gas company established in 1950. The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company partially owned by a member of current management. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Callon is focused on the acquisition, development, exploration and exploitation of unconventional oil and natural gas reserves in the Permian Basin in West Texas. In late 2013, with the sale of its remaining offshore assets in the Gulf of Mexico, the Company completed the onshore strategic repositioning it initiated in 2009.

Basis of presentation

Unless otherwise indicated, all dollar amounts included within the footnotes to the financial statements are presented in thousands, except for per share and per unit data.

The interim consolidated financial statements of the Company have been prepared in accordance with (1) GAAP, (2) the SEC's instructions to Quarterly Report on Form 10-Q and (3) Rule 10-01 of Regulation S-X, and include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also has subsidiaries, namely Callon Offshore Production, Inc. and Mississippi Marketing, Inc.

These interim consolidated financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2013. The balance sheet at December 31, 2013 has been derived from the audited financial statements at that date. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the year ended December 31, 2014.

In the opinion of management, the accompanying unaudited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account and transaction eliminations, necessary to present fairly the Company's financial position, the results of its operations and its cash flows for the periods indicated. When necessary to ensure consistent presentation, certain prior year amounts may be reclassified to conform to presentation in the current period. Certain prior year amounts have been reclassified to conform to current year presentation.

Recently issued accounting policies

In May 2014, the Financial Accounting Standards Board issued accounting standards update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU No. 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. The guidance in ASU No. 2014-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. Early adoption is not permitted. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

Note 2 – Oil and Natural Gas Properties

Acquisitions

In the first quarter of 2014, the Company acquired 1,527 net acres in Upton and Reagan Counties, Texas, which are located in the southern portion of the Midland Basin near its existing core development fields, for an aggregate cash purchase price of $8,200. The properties bear a working interest of 100% and an average net revenue interest of 78%.

On October 8, 2014, the Company completed the acquisition of certain undeveloped acreage and producing oil and gas properties located in Midland, Andrews, Ector and Martin Counties, Texas (the "Acquisition") for an aggregate cash purchase price of $205,011, including estimated purchase price adjustments of $7,561 based on an effective date of May 1, 2014. The Company assumed operatorship of the properties on November 1, 2014, and acquired a 62% working interest (46.5% net revenue interest) in the Acquisition. The aggregate cash purchase price was funded with a combination of the net proceeds from an equity offering of $122,514 and a portion of the proceeds from borrowings under a new $300,000 secured second lien term loan (the "New Second Lien Loan"). For additional information on the debt transactions and equity offering, see Notes 4 and 9, respectively.

The Acquisition was accounted for under the purchase method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The following purchase price allocation is preliminary and based on management's estimates of the fair value of the assets acquired and liabilities assumed as of the date of this Form 10-Q. The preliminary purchase price allocation is subject to change based on numerous factors, including the final adjusted purchase price and the final estimated fair value of the assets acquired and liabilities assumed. Any such adjustments to the preliminary estimates of fair value could be material.

The following table summarizes the estimated acquisition date fair values of the net assets acquired:

Oil and natural gas properties	$ 92,847
Unevaluated oil and natural gas properties	113,092
Asset retirement obligations	(928)
Net assets to be acquired	$ 205,011

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The following unaudited summary pro forma financial information for the three and nine month periods ended September 30, 2014 has been presented for illustrative purposes only and does not purport to represent what the Company's results of operations would have been if the Acquisition had occurred as presented, or to project the Company's results of operations for any future periods. The pro forma financial information was prepared assuming the Acquisition and the debt transactions and equity offering discussed in Notes 4 and 9, respectively, occurred as of January 1, 2013. The pro forma adjustments are based on available information and certain assumptions that management believes are reasonable, including revenue, lease operating expenses, production taxes, depreciation, depletion and amortization expense, accretion expense, interest expense and capitalized interest.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 48,035	$ 43,253	$ 142,040	$ 114,078
Income from operations	15,269	13,721	45,453	28,481
Income available to common stockholders	11,102	766	16,571	2,477
Net income per common share:				
Basic	$ 0.19	$ 0.01	$ 0.30	$ 0.05
Diluted	$ 0.19	$ 0.01	$ 0.29	$ 0.05

Note 3 - Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share:

(share amounts in thousands)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income (loss)	$ 12,201	$ 1,082	$ 18,804	$ 1,040

Preferred stock dividends	(1,974)	(1,974)	(5,921)	(2,654)
Income (loss) available to common stockholders	$ 10,227	$ (892)	$ 12,883	$ (1,614)
Weighted average shares outstanding	43,187	40,321	41,370	40,064
Dilutive impact of restricted stock	1,024	—	1,140	—
Weighted average shares outstanding for diluted income (loss) per share	44,211	40,321	42,510	40,064
Basic income (loss) per share	$ 0.24	$ (0.02)	$ 0.31	$ (0.04)
Diluted income (loss) per share	$ 0.23	$ (0.02)	$ 0.30	$ (0.04)
The following were excluded from the diluted earnings per share calculation because their effect would be anti-dilutive:				
Stock options	30	52	30	52
Restricted stock	—	239	—	239

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	September 30, 2014	December 31, 2013
Principal components:		
Credit Facility	$ 20,000	$ 22,000
Second Lien Loan	82,500	—
13% Senior Notes, principal	—	48,481
Total principal outstanding	102,500	70,481
13% Senior Notes, unamortized deferred credit	—	5,267
Total carrying value of borrowings	$ 102,500	$ 75,748

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Senior secured revolving credit facility (the "Credit Facility")

On March 11, 2014, the Company entered into the Fifth Amended and Restated Credit Agreement to the Credit Facility with a maturity date of March 11, 2019. JPMorgan Chase Bank, N.A. is Administrative Agent, and participating lenders include Regions Bank, Citibank, N.A., Capital One, N.A., KeyBank, N.A., Whitney Bank, IberiaBank, N.A., OneWest Bank, N.A., SunTrust Bank and Royal Bank of Canada. The total notional amount available under the Credit Facility is $500,000. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. As of September 30, 2014 the Credit Facility's borrowing base was $155,000. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. In conjunction with the closing of the Acquisition on October 8, 2014, the borrowing base on the Company's Credit Facility was amended to $250,000.

As of September 30, 2014, the balance outstanding on the Credit Facility was $20,000 with a weighted-average interest rate of 2.43%, calculated as the LIBOR plus a tiered rate ranging from 1.75% to 2.75%, which is determined based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the borrowing base.

Term loans

On March 11, 2014, the Company entered into the Secured Second Lien Term Loan (the "Second Lien Loan") in an aggregate amount of up to $125,000, including initial commitments of $100,000 and additional availability of $25,000 subject to the consent of two-thirds of the lenders and compliance with financial covenants after giving effect to such increase. The Second Lien Loan matures on September 11, 2019, and is not subject to mandatory prepayments unless new debt or preferred stock is issued. The Second Lien Loan may be prepaid at the Company's option, subject to a prepayment premium. The prepayment amount is (i) 102% if the prepayment event occurs prior to March 11, 2015, and (ii) 101% if the prepayment event occurs on or after March 15, 2015 but before March 15, 2016, and (iii) 100% for prepayments made on or after March 15, 2016. The Second Lien Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement. On April 10, 2014, the Company drew an initial amount of $62,500 with an original issue discount of 1.0%. In addition, the Second Lien Loan carries a commitment fee of 0.5% per annum, payable quarterly, on the unused portion of the initial commitment amount until March 11, 2015. As of September 30, 2014, the balance outstanding on the Second Lien Loan was $82,500 with an interest rate of 8.75%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.75% per annum.

Subsequent to September 30, 2014, the Second Lien Loan was repaid in full using proceeds from the New Second Lien Loan discussed below, resulting in a loss on early extinguishment of debt of $3,054. In conjunction with the closing of the Acquisition on October 8, 2014, the Company refinanced its Second Lien Loan with the New Second Lien Loan with a maturity date of October 8, 2021. The Royal Bank of Canada is Administrative Agent, and participants include several institutional lenders. On October 8, 2014, the Company drew an initial amount of $300,000 with a discount of 2.0% and an interest rate of 8.5%, calculated at a rate of LIBOR (subject to a floor rate of 1.0%) plus 7.5% per annum. The New Second Lien Loan may be prepaid at the Company’s option, subject to a prepayment premium. The prepayment amount is (i) 102% if the prepayment event occurs prior to October 8, 2015, and (ii) 101% if the prepayment event occurs on or after October 8, 2015 but before October 8, 2016, and (iii) 100% for prepayments made on or after October 8, 2016. The New Second Lien Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement.

13% senior notes due 2016 (“Senior Notes”) and deferred credit

On April 11, 2014, the Company completed a full redemption of the remaining $48,481 principal amount of outstanding Senior Notes using proceeds from the Second Lien Loan. The redemption resulted in a net $3,205 gain on the early extinguishment of debt (including $4,780 of accelerated deferred credit amortization). The gain represents the difference between the $50,057 paid for the redemption of the Senior Notes ($1,576 of redemption costs, primarily the call premium) and the carrying value of the remaining Senior Notes of $53,261 (inclusive of $4,780 of deferred credit). The Company also paid $193 in accrued interest through the redemption date. Upon the redemption, the indenture governing the Senior Notes was discharged in accordance with its terms.

Restrictive covenants

The Company's Credit Facility and Second Lien Loan contain various covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. The Company was in compliance with these covenants at September 30, 2014.

Note 5 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil and natural gas prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil and natural gas production. The Company utilizes a mix of collars, swaps, puts, calls and similar derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative instruments exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument; see Note 6 for additional information regarding fair value.

The Company executes commodity derivative contracts under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

Financial statement presentation and settlements

Settlements of the Company's derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a benchmark price, such as the NYMEX price. To determine the fair value of the Company's derivative instruments, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See Note 6 for additional information regarding fair value.

Derivatives not designated as hedging instruments

The Company elected not to designate its derivative contracts as accounting hedges under Accounting Standards Codification 815. Consequently, the Company records its derivative contracts at fair value in the consolidated balance sheet and records changes in fair value as a gain or loss on derivative contracts in the consolidated statement of operations. Cash settlements are also recorded as gain or loss on derivative contracts in the consolidated statement of operations.

The following table reflects the fair value of the Company's derivative instruments for the periods presented:

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	09/30/14	12/31/2013	09/30/2014	12/31/2013	09/30/2014	12/31/2013
Natural gas	Current	Fair value of derivatives	$ —	$ —	$ (47)	$ —	$ (47)	$ —
Natural gas	Current	Fair value of derivatives	—	60	—	—	—	60
Natural gas	Non-current	Other long-term liabilities	—	—	(41)	(72)	(41)	(72)
Oil	Current	Fair value of derivatives	4,842	—	(418)	(1,036)	4,424	(1,036)
Oil	Non-current	Other long-term assets	1,169	—	—	—	1,169	—

Oil	Non-current	Other long-term liabilities	—	—	(824)	—	(824)	—
	Totals		$ 6,011	$ 60	$ (1,330)	$ (1,108)	$ 4,681	$ (1,048)

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial

statements are presented in thousands, except for per share and per unit data)

As previously discussed, the Company’s derivative contracts are subject to master netting arrangements. The Company’s policy is to present the fair value of derivative contracts on a net basis in the consolidated balance sheet. The following presents the impact of this presentation to the Company’s recognized assets and liabilities at September 30, 2014:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$ 4,968	$ (126)	$ 4,842
Long-term assets: Fair value of derivatives	1,169	—	1,169
Current liabilities: Fair value of derivatives	$ (591)	$ 126	$ (465)
Long-term liabilities: Fair value of derivatives	(865)	—	(865)

For the periods indicated, the Company recorded the following related to its derivatives in the consolidated statement of operations as gain or loss on derivative contracts:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Natural gas derivatives				
Net gain (loss) on settlements	$ 35	$ (16)	$ (144)	$ (123)
Net gain (loss) on fair value adjustments	55	81	(77)	178
Total gain (loss)	$ 90	$ 65	$ (221)	$ 55
Oil derivatives				
Net gain (loss) on settlements	$ (497)	$ (618)	$ (2,838)	$ 804
Net gain (loss) on fair value adjustments	10,351	(3,133)	5,805	(2,982)
Total gain (loss)	$ 9,854	$ (3,751)	$ 2,967	$ (2,178)

Total gain (loss) on derivative instruments	$ 9,944	$ (3,686)	$ 2,746	$ (2,123)

Footnotes to the Financial Statements (continued)

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(Unless otherwise indicated, dollar amounts included in the footnotes to the financial statements are presented in thousands, except for per share and per unit data)

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of September 30, 2014:

	For the Three Months Ended				
Oil contracts	December 31, 2014	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Collar contracts combined with short puts (three-way collar):					
Volume (MBbls)	—	158	159	—	—
Price per Bbl					
Ceiling (short call)	$ —	$ 99.10	$ 99.10	$ —	$ —
Floor (long put)	$ —	$ 90.00	$ 90.00	$ —	$ —
Short put	$ —	$ 75.00	$ 75.00	$ —	$ —
Swap contracts:					
Total volume (MBbls)	267	171	136	129	74
Weighted average price per Bbl	$ 93.66	$ 92.25	$ 92.18	$ 92.25	$ 92.20
Put spreads:					
Volume (MBbls)	—	—	—	138	138
Long put price per Bbl	$ —	$ —	$ —	$ 90.00	$ 90.00
Short put price per Bbl	$ —	$ —	$ —	$ 75.00	$ 75.00
Swap contracts combined with short put:					
Volume (MBbls)	92	—	—	—	—
Swap price per Bbl	$ 93.35	$ —	$ —	$ —	$ —
Short put price per Bbl	$ 70.00	$ —	$ —	$ —	$ —

	For the Three Months Ended				
Natural gas contracts	December 31, 2014	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Collar contracts combined with short puts (three-way collar):					
Volume (BBtu)	—	248	227	207	161
Weighted average price per MMBtu					
Ceiling (short call)	$ —	$ 4.67	$ 4.32	$ 4.32	$ 4.32
Floor (long put)	$ —	$ 4.00	$ 3.85	$ 3.85	$ 3.85
Short put	$ —	$ 3.50	$ 3.25	$ 3.25	$ 3.25
Swap contracts:					
Total volume (BBtu)	414	248	227	207	161
Weighted average price per MMBtu	$ 4.04	$ 3.98	$ 3.98	$ 3.98	$ 3.98
Call contracts:					
Volume (BBtu)	115	—	—	—	—
Short call price per MMBtu (a)	$ 4.75	$ —	$ —	$ —	$ —
Long call price per MMBtu (a)	$ 4.75	$ —	$ —	$ —	$ —
Swap contracts combined with short calls:					
Swap volume (BBtu)	184	—	—	—	—
Swap price per MMBtu	$ 4.25	$ —	$ —	$ —	$ —
Short call volume (BBtu)	—	108	109	110	111
Short call price per MMBtu	$ —	$ 5.00	$ 5.00	$ 5.00	$ 5.00

(a) Offsetting contracts.

Footnotes to the Financial Statements (continued)

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(Unless otherwise indicated, dollar amounts included in the footnotes to the financial statements are presented in thousands, except for per share and per unit data)

Subsequent Event

The following derivative contracts were executed subsequent to September 30, 2014:

	For the Three Months Ended			
Natural gas contracts	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Swap contracts:				
Total volume (BBtu)	23	10	12	67
Weighted average price per MMBtu	$ 3.91	$ 3.91	$ 3.91	$ 3.91

Note 6 - Fair Value Measurements

The fair value hierarchy outlined in the relevant accounting guidance gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable, and these valuations have the lowest priority.

Fair Value of Financial Instruments

Cash, cash equivalents, restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The Company's debt is recorded at the carrying amount in the consolidated balance sheet. The carrying amount of floating-rate debt approximated fair value because the interest rates were variable and reflective of market rates.

The following table summarizes the respective carrying and fair values at:

	September 30, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 20,000	$ 20,000	$ 22,000	$ 22,000
Second Lien Loan	82,500	82,500	—	—
13% Senior Notes due 2016 (a)	—	—	53,748	50,299
Total	$ 102,500	$ 102,500	$ 75,748	$ 72,299

(a) Fair value is calculated only in relation to the $48,481 principal outstanding of the Senior Notes at December 31, 2013 and excludes the remaining $5,267 deferred credit. The fair value of the Senior Notes, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. See Note 4 for additional information.

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis in the consolidated balance sheet. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using an income approach valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. The Company believes that the majority of the inputs used to calculate the commodity derivative instruments fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 5 for additional information regarding the Company's derivative instruments.

(Unless otherwise indicated, dollar amounts included in the footnotes to the financial statements are presented in thousands, except for per share and per unit data)

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The following tables present the Company's assets and liabilities measured at fair value on a recurring basis:

September 30, 2014	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ 4,842	$ —	$ 4,842
Derivative financial instruments (non-current)	Other long-term assets	—	1,169	—	1,169
Sub-total assets		$ —	$ 6,011	$ —	$ 6,011
Liabilities					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ (465)	$ —	$ (465)
Derivative financial instruments (non-current)	Other long-term liabilities	—	(865)	—	(865)
Sub-total liabilities		$ —	$ (1,330)	$ —	$ (1,330)
Total net assets (liabilities)		$ —	$ 4,681	$ —	$ 4,681

December 31, 2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ 60	$ —	$ 60
Derivative financial instruments (non-current)	Other long-term assets	—	—	—	—
Sub-total assets		$ —	$ 60	$ —	$ 60
Liabilities					
Derivative financial instruments (current)	Fair value of derivatives	$ —	$ (1,036)	$ —	$ (1,036)
Derivative financial instruments (non-current)	Other long-term liabilities	—	(72)	—	(72)
Sub-total liabilities		$ —	$ (1,108)	$ —	$ (1,108)
Total net assets (liabilities)		$ —	$ (1,048)	$ —	$ (1,048)

Note 7 - Income Taxes

The Company provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses and state income taxes. The effective tax rate for the three months ended September 30, 2014 and 2013 was 37% and 30%, respectively. The effective tax rate for the nine months ended September 30, 2014 and 2013 was 40% and 48%, respectively.

Note 8 - Asset Retirement Obligations

The table below summarizes the Company's asset retirement obligations activity for the nine months ended September 30, 2014:

Asset retirement obligations at January 1, 2014	$ 6,732
Accretion expense	603
Liabilities incurred	542
Liabilities settled	(1,908)
Revisions to estimate	450
Asset retirement obligations at end of period	6,419
Less: Current asset retirement obligations	5,138
Long-term asset retirement obligations at September 30, 2014	$ 1,281

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheets as restricted investments were $3,802 at September 30, 2014. These investments include primarily U.S. Government securities, and are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 9 – Equity Transactions

10% Series A Cumulative Preferred Stock ("Preferred Stock")

Holders of the Company's Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10.0% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends are payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by our Board of Directors. For the quarter ended September 30, 2014, the Board declared a dividend of $1.25 per share, or a total of $1,974, on the Company's Preferred Stock. Dividends for the nine months ended September 30, 2014 were $5,921.

The Preferred Stock has no stated maturity and is not be subject to any sinking fund or other mandatory redemption. On or after May 30, 2018, the Company may, at its option, redeem the Preferred Stock, in whole or in part, by paying $50.00 per share, plus any accrued and unpaid dividends to the redemption date.

Following a change of control, the Company will have the option to redeem the Preferred Stock, in whole but not in part for $50.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), to the redemption date. If the Company does not exercise its option to redeem the Preferred Stock upon a change of control, the holders of the Preferred Stock have the option to convert the Preferred Stock into a number of shares of the Company's common stock based on the value of the common stock on the date of the change of control as determined under the certificate of designations for the Preferred Stock. If the change of control occurred on September 30, 2014, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of the common stock on such date ($8.81) as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 5.7 shares of common stock. If the Company exercises its redemption rights relating to shares of Preferred Stock, the holders of Preferred Stock will not have the conversion right described above.

Common Stock

On September 15, 2014 the Company completed an underwritten public offering of 12,500,000 shares of its common stock at $9.00 per share, before underwriting discounts, and the exercise in full by the underwriters of their option to purchase 1,875,000 additional shares of common stock at $9.00 per share. The Company received net proceeds of approximately $122,514, after the underwriting discounts and estimated offering costs, which were used to fund a portion of the purchase price of the Acquisition (see Note 2).

Note 10 – Other

Operating leases

In April 2012, the Company contracted a drilling rig (the “Cactus 1 Rig”) for a term of two years, which it subsequently renewed in March 2014 for an additional two-year term ending in April 2016. In April 2014, the Company contracted an additional horizontal drilling rig (the “Cactus 2 Rig”) for a term of two years ending in April 2016. The Cactus 2 Rig replaced a previously contracted horizontal drilling rig, which was cancelled in March 2014. In August 2014, the Company signed a one-year contract for a vertical drilling rig to be used as part of its horizontal drilling program, drilling the vertical section of horizontal wells. The rig lease agreements include early termination provisions that would reduce the minimum rentals under the agreement, and also include early termination payments that would be reduced assuming the lessor is able to re-charter the rig and staffing personnel to another lessee. Lease payments in 2014, 2015 and 2016 are expected to approximate $19,443 (with $6,256 remaining for the balance of 2014 at September 30, 2014), $23,164 and $4,795, respectively.

Other property and equipment

As disclosed in the Company’s Annual Report on Form 10-K for the year ended December 31, 2013, the Company made a decision to abandon certain specialized deep water property and equipment received as part of a prior settlement agreement related to various disputes with a previous joint interest partner as a result of the unsuccessful marketing of such assets. Accordingly, the Company recognized an impairment charge of $1,707 related to such property and equipment in the year ended December 31, 2013. Subsequent to the filing of the Annual Report on Form 10-K, the Company entered into an agreement to sell the property and equipment to a third

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party. While the third party had previously performed some initial inspection and evaluation of the equipment, based on the amount of time the equipment had been unsuccessfully marketed and the feedback from potential buyers, management concluded the likelihood of completing a sale of the equipment was low, resulting in the decision to abandon the equipment and recognize an impairment charge in 2013. As a result of the subsequent sale of the property and equipment, the Company recognized a gain of $1,080 in the first quarter 2014.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations (continued)

Special Note Regarding Forward Looking Statements

All statements, other than statements of historical fact, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve quantities, present value and growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “plan,” “forecast,” “target” or si

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

· the timing and extent of changes in market conditions and prices for oil, natural gas and NGLs (including regional basis differentials),
· our ability to transport our production to the most favorable markets or at all,
· the timing and extent of our success in discovering, developing, producing and estimating reserves,
· our ability to fund our planned capital investments,
· the impact of government regulation, including regulation of endangered species, any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives,
· the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services,
· our future property acquisition or divestiture activities,
· the effects of weather,
· increased competition,
· the financial impact of accounting regulations and critical accounting policies,
· the comparative cost of alternative fuels,
·

conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed,
- credit risk relating to the risk of loss as a result of non-performance by our counterparties, and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or in our 2013 Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

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General

The following management's discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying unaudited consolidated financial statements and our 2013 Annual Report on Form 10-K, which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Form 10-Q.

We are an independent oil and natural gas company established in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin in West Texas, and more specifically, the Midland Basin. Our operations to date have been predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through acreage purchases, joint ventures and asset swaps. Our production was approximately 82% oil and 18% natural gas for the nine months ended September 30, 2014. On September 30, 2014, our net acreage position in the Permian Basin was approximately 22,775 net acres, including 7,496 exploratory net acres in the Northern Midland Basin.

Recent Developments

Acquisition

On October 8, 2014, the Company completed the acquisition of certain undeveloped acreage and producing oil and gas properties located in Midland, Andrews, Martin and Ector Counties, Texas. Including estimated purchase price adjustments, total net consideration paid for the Acquisition was approximately $205 million for an estimated 62% working interest (46.5% net revenue interest).

Key attributes of the acquired fields include:

- 6,230 gross (3,862 net) surface acres, 95% of which are located in Midland and Andrews Counties, in close proximity to the Company's existing Carpe Diem and Pecan Acres fields in Midland County
- 188 gross (117 net) potential horizontal drilling locations targeting the Wolfcamp B, Lower Spraberry and Middle Spraberry zones which are currently producing in offsetting fields
- 252 gross (156 net) additional potential horizontal drilling locations targeting four other prospective zones including the Wolfcamp A, Wolfcamp D (Cline), Clearfork and Jo Mill

- 1,324 BOE/d (65% oil) average net daily production during the third quarter of 2014
- 100% of targeted horizontal zones held by production

The Company assumed operatorship of the properties November 1, 2014 and currently owns an estimated 62.7% working interest after the recent purchase of additional working interests in October 2014.

Common Stock Offering

On September 15, 2014, the Company completed an equity offering for $129 million in gross proceeds. The offering consisted of 12,500,000 shares of the Company’s common stock at a price to the public of $9.00 per share, before underwriting discounts, and the exercise in full by the underwriters of their option to purchase 1,875,000 additional shares of common stock at $9.00 per share. See Note 9 in the Footnotes to the Financial Statements for additional information about the Company’s equity offering.

Debt Transactions

In conjunction with the closing of the Acquisition on October 8, 2014, the borrowing base under the Company’s Credit Facility was amended to $250 million and the existing $125 million secured second lien term loan was replaced with a new $300 million secured

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second lien term loan. See Note 4 in the Footnotes to the Financial Statements for additional information about the Company's recent debt transactions.

Operational Highlights

Following the sale of our remaining offshore and Haynesville properties in the fourth quarter of 2013, all of our producing properties are located in the Permian Basin. Our Permian production grew 130% and 158% for the three and nine months ended September 30, 2014, respectively, compared to the same periods of 2013, increasing to 519 MBOE from 226 MBOE and 1,392 MBOE from 539 MBOE for the comparative three and nine months periods, respectively.

	Net Production (MBOE) Three Months Ended September 30,			
	2014	2013	Change	% Change
Onshore:				
Southern Midland Basin	393	181	212	117%
Central Midland Basin	123	45	78	173%
Northern Midland Basin	3	—	3	100%
Total Permian	519	226	293	130%
Offshore and other (a)	—	176	(176)	(100)%
Total	519	402	117	29%

	Net Production (MBOE) Nine Months Ended September 30,			
	2014	2013	Change	% Change
Onshore:				
Southern Midland Basin	1,080	397	683	172%
Central Midland Basin	297	142	155	109%
Northern Midland Basin	15	—	15	100%
Total Permian	1,392	539	853	158%
Offshore and other (a)	—	521	(521)	(100)%
Total	1,392	1,060	332	31%

(a) In late 2013, we sold the remaining interests in our offshore fields and in the Haynesville shale.

The following table sets forth productive wells as of September 30, 2014:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	146	127.1	—	—
Royalty interest	3	0.1	—	—
Total	149	127.2	—	—

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a BOE basis. However, most of our wells produce both oil and natural gas.

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The following table summarizes the Company’s drilling progress in the Permian Basin for the nine months ended September 30, 2014:

	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin						
Vertical wells	1	1.0	1	1.0	—	—
Horizontal wells	17	15.6	18	16.6	2	2.0
Total	18	16.6	19	17.6	2	2.0
Central Midland Basin						
Vertical wells	3	1.3	3	1.3	—	—
Horizontal wells	5	4.2	4	3.4	3	2.5
Total	8	5.5	7	4.7	3	2.5
Northern Midland Basin						
Vertical wells	2	1.5	1	0.8	—	—
Total	2	1.5	1	0.8	—	—
Total vertical wells	6	3.8	5	3.1	—	—
Total horizontal wells	22	19.8	22	19.9	5	4.5
Total	28	23.6	27	23.0	5	4.5

(a) Completions include wells drilled prior to 2014.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions, the sale of debt and equity securities and asset dispositions. Our primary uses of capital have been for the acquisition, development, exploration and exploitation of oil and natural gas properties, in addition to refinancing of debt instruments.

We recently amended the borrowing base under our Credit Facility, replaced our Second Lien Loan with a New Second Lien Loan and completed a common stock offering to support the funding of the Acquisition and our ongoing operations and acquisition initiatives which are discussed in greater detail in Notes 2, 4 and 9 in the Footnotes to the Financial Statements. In addition, we regularly evaluate other sources of capital to complement our cash flow from operations and other sources of capital as we pursue our long-term growth plans in the Permian Basin.

Based upon current commodity price expectations for 2014, we believe that our cash flow from operations and borrowings under our Credit Facility and New Second Lien Loan will be sufficient to fund our operations for 2014, including any deficiencies in the Company's current net working capital. However, future cash flows are subject to a number of variables, including forecast production volumes and commodity prices. Over 95% of our current 2014 capital program is allocated to properties we operate and, as a result, the amount and timing of a substantial portion of our planned capital expenditures is largely discretionary in the event we determine it prudent to curtail drilling and completion operations due to capital constraints or reduced returns on investment in periods of commodity price weakness.

Cash and cash equivalents increased $4.2 million in the nine months ended September 30, 2014 to $7.2 million compared to $3.0 million at December 31, 2013. As of October 31, 2014, our available liquidity increased to $230.4 million, a $166.4 million increase over year-end 2013.

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Liquidity and cash flow

	Nine Months Ended September 30,	
	2014	2013
Net cash provided by operating activities	$ 57.7	$ 35.2
Net cash used in investing activities	(197.4)	(109.9)
Net cash provided by financing activities	143.9	74.4
Net change in cash	$ 4.2	$ (0.3)

Operating activities. For the nine months ended September 30, 2014, net cash provided by operating activities was $57.7 million, compared to $35.2 million for the same period in 2013. The increase was primarily due to an increase in oil sales and a reduction in lease operating expense, partially offset by losses on the settlement of derivative contracts, and an increase in production taxes. Production and realized prices are discussed below in Results of Operations. See Notes 5 and 6 in the Footnotes to the Financial Statements for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. For the nine months ended September 30, 2014, net cash used in investing activities was $197.4 million compared to $109.9 million for the same period in 2013. The $87.5 million increase in cash used in investing activities was primarily attributable to an $87.7 million increase in drilling and completion activities in the Permian Basin driven by the addition of a second horizontal drilling rig in August 2013 and acreage acquisitions. Offsetting these increases was an $11.0 million acquisition completed in the 2013 period.

Capital expenditures for the nine months ended September 30, 2014 include the following (in millions):

Southern Midland Basin	$ 127.7
Central Midland Basin	40.4
Northern Midland Basin	0.4
Total operational expenditures	168.5
Capitalized general and administrative costs allocated directly to exploration and development projects	9.4
Capitalized interest	1.7
Total capitalized general and administrative and interest costs	11.1
Total operational expenditures inclusive of capitalized general and administrative and interest costs	179.6
Acquisitions	9.2

Total capital expenditures	$ 188.8

Financing activities. For the nine months ended September 30, 2014, net cash provided by financing activities was $143.9 million compared to cash provided by financing activities of $74.4 million during the same period of 2013. Net cash provided by financing activities during the nine months ended September 30, 2014 included $122.5 million of net proceeds from the issuance of common stock and a net $77.4 million of borrowings on our Credit Facility and Second Lien Loan, offset by a $50.1 million redemption of our Senior Notes. In addition, the Company paid approximately $5.9 million in preferred stock dividends. See Note 9 in the Footnotes to the Financial Statements for additional information about the Company’s equity offering.

2014 capital expenditures

Our 2014 operational capital budget approximates $215 million, excluding acquisitions completed in 2014 (see Note 2) and capitalized general and administrative and interest costs. This budgeted amount includes plans to drill up to 30 gross (26.3 net) horizontal and seven gross (4.2 net) vertical wells, while completing 29 gross (27.3 net) horizontal and five gross (3.1 net) vertical wells.

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As described in Note 2 in the Footnotes to the Financial Statements, on October 8, 2014, we completed the acquisition of certain undeveloped acreage and oil and gas producing properties located in Midland, Andrews, Martin and Ector Counties, Texas. We currently plan to complete two horizontal wells on this new acreage in the fourth quarter, which we forecast will add approximately $5.6 million to our original operational capital budget.

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Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	Three Months Ended September 30,			
	2014	2013	Change	% Change
Net production:				
Oil (MBbls)	425	257	168	65%
Natural gas (MMcf)	565	864	(299)	(35)%
Total production (MBOE)	519	402	117	29%
Average daily production (BOE/d)	5,641	4,418	1,223	28%
% oil (BOE basis)	82%	64%	—	—
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 85.52	$ 105.11	$ (19.59)	(19)%
Oil (Bbl) (including impact of cash settled derivatives)	84.35	102.71	(18.36)	(18)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 5.86	$ 4.38	$ 1.48	34%
Natural gas (Mcf) (including impact of cash settled derivatives)	5.92	4.36	1.56	36%
Total (BOE) (excluding impact of cash settled derivatives)	$ 76.41	$ 76.61	$ (0.20)	(0.3)%
Total (BOE) (including impact of cash settled derivatives)	75.52	75.03	0.49	0.7%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 36,346	$ 27,014	$ 9,332	35%
Natural gas revenue	3,311	3,783	(472)	(12)%
Total	$ 39,657	$ 30,797	$ 8,860	29%
Additional per BOE data:				
Sales price	$ 76.41	$ 76.61	$ (0.20)	(0.3)%
Lease operating expense	12.08	13.11	(1.03)	(8)%
Production taxes	4.33	2.47	1.86	75%
Operating margin	$ 60.00	$ 61.03	$ (1.03)	(2)%

	Nine Months Ended September 30,			
	2014	2013	Change	% Change
Net production:				
Oil (MBbls)	1,162	661	501	76%
Natural gas (MMcf)	1,381	2,389	(1,008)	(42)%
Total production (MBOE)	1,392	1,060	332	31%
Average daily production (BOE/d)	5,099	3,883	1,216	31%
% oil (BOE basis)	83%	62%	—	—
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 90.33	$ 99.27	$ (8.94)	(9)%

Oil (Bbl) (including impact of cash settled derivatives)	87.89	100.48	(12.59)	(13)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 6.14	$ 4.39	$ 1.75	40%
Natural gas (Mcf) (including impact of cash settled derivatives)	6.04	4.34	1.70	39%
Total (BOE) (excluding impact of cash settled derivatives)	$ 81.50	$ 71.79	$ 9.71	14%
Total (BOE) (including impact of cash settled derivatives)	79.35	72.43	6.92	10%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 104,965	$ 65,615	$ 39,350	60%
Natural gas revenue	8,479	10,483	(2,004)	(19)%
Total	$ 113,444	$ 76,098	$ 37,346	49%
Additional per BOE data:				
Sales price	$ 81.50	$ 71.79	$ 9.71	14%
Lease operating expense	10.68	15.48	(4.80)	(31)%
Production taxes	4.62	2.09	2.53	121%
Operating margin	$ 66.20	$ 54.22	$ 11.98	22%

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Revenues

The following tables are intended to reconcile the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

(in thousands)	Oil	Natural Gas	Total
Revenues for the three months ended September 30, 2013	$ 27,014	$ 3,783	$ 30,797
Volume increase (decrease)	17,601	(1,310)	16,291
Price increase (decrease)	(8,269)	838	(7,431)
Net increase (decrease) in 2014	9,332	(472)	8,860
Revenues for the three months ended September 30, 2014	$ 36,346	$ 3,311	$ 39,657

(in thousands)	Oil	Natural Gas	Total

Revenues for the nine months ended September 30, 2013	$ 65,615	$ 10,483	$ 76,098
Volume increase (decrease)	49,712	(4,425)	45,287
Price increase (decrease)	(10,362)	2,421	(7,941)
Net increase (decrease) in 2013	39,350	(2,004)	37,346
Revenues for the nine months ended September 30, 2014	$ 104,965	$ 8,479	$ 113,444

Oil revenue

For the quarter ended September 30, 2014, oil revenues of $36.3 million increased $9.3 million, or 35%, compared to revenues of $27.0 million for the same period of 2013. Contributing to the increase in oil revenue was a 65% increase in production partially offset by a 19% decrease in the average realized sales price. The increase in production was primarily attributable to a 254 MBbls increase in production from our Permian properties as a result of an increased number of producing wells from acquisitions and our horizontal drilling program. Partially offsetting this increase was an 87 MBbls decline in production due to the sale of our deep water Medusa field in the fourth quarter of 2013 as well as normal and expected declines from our existing wells.

For the nine months ended September 30, 2014, oil revenues of $105.0 million increased $39.4 million, or 60%, compared to revenues of $65.6 million for the same period of 2013. The increase primarily related to a 76% increase in total production, while the average realized sales price decreased 9%. The increase in production was wholly attributable to a 749 MBbls increase in Permian production resulting from an increased number of producing wells as mentioned above. Partially offsetting the Permian increase was a 249 MBbls decline in production due to the sale of the Medusa field as well as normal and expected declines from our existing wells.

Natural gas revenue (including NGLs)

Natural gas revenues of $3.3 million decreased $0.5 million, or 12%, during the three months ended September 30, 2014 compared to $3.8 million for the same period of 2013. The decrease primarily relates to a 35% decrease in natural gas volumes offset by a 34% increase in the average price realized, which rose to $5.86 per Mcf from $4.38 per Mcf. The decrease in production was primarily attributable to a 534 MMcf decrease in production due to the sale of our offshore fields and Haynesville well in the fourth quarter of 2013. Offsetting these declines was a 236 MMcf increase in production from our Permian properties resulting from an increased number of producing wells as mentioned above.

Natural gas revenues of $8.5 million decreased $2.0 million, or 19%, during the nine months ended September 30, 2014 compared to $10.5 million for the same period of 2013. The average realized price increased to $6.14 per Mcf from $4.39 per Mcf, or 40%, while total production decreased 42%. The decrease in production was primarily attributable to a 1,617 MMcf decrease in production due to the sale of our offshore fields and Haynesville well in the fourth quarter of 2013. Offsetting the production decline was a 623 MMcf increase in production from our Permian properties resulting from an increased number of producing wells as mentioned above.

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Operating Expenses

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to extract oil and natural gas out of the ground and deliver to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes include severance and ad valorem taxes. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, public company costs, vesting of equity and liability awards under share-based compensation plans and related mark-to-market valuation adjustments over time, fees for audit and other professional services and legal compliance.

Accretion expense. The Company is required to record the estimated fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligations and reported as accretion expense within operating expenses in the consolidated statements of operations.

(in thousands, except per unit amounts)	Three Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
	2014	BOE	2013	BOE	$	%	$	%
Lease operating expenses	$ 6,270	$ 12.08	$ 5,270	$ 13.11	1,000	19%	(1.03)	(8)%
Production taxes	2,247	4.33	991	2.47	1,256	127%	1.86	75%
Depreciation, depletion and amortization	16,115	31.05	11,907	29.62	4,208	35%	1.43	5%
General and administrative	3,261	6.28	5,826	14.49	(2,565)	(44)%	(8.21)	(57)%
Accretion expense	202	0.39	458	1.14	(256)	(56)%	(0.75)	(66)%

	Nine Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
	2014	BOE	2013	BOE	$	%	$	%
Lease operating expenses	$ 14,863	$ 10.68	$ 16,412	$ 15.48	(1,549)	(9)%	(4.80)	(31)%
Production taxes	6,429	4.62	2,217	2.09	4,212	190%	2.53	121%
Depreciation, depletion and amortization	38,635	27.76	33,603	31.70	5,032	15%	(3.94)	(12)%
General and administrative	23,707	17.03	14,110	13.31	9,597	68%	3.72	28%
Accretion expense	603	0.43	1,556	1.47	(953)	(61)%	(1.04)	(71)%
Gain on sale of other property and equipment	(1,080)	nm	—	nm	(1,080)	—	nm	nm

*nm = not meaningful

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Lease operating expenses (“LOE”)

LOE for the three months ended September 30, 2014 increased by 19% to $6.3 million compared to $5.3 million for the same period of 2013 primarily due to $2.7 million in costs related to the growth in Permian production and operations, including an increase in workover expenses associated with the impact of accelerated horizontal well activity on surrounding producing wells. These increases were partially offset by a decrease in costs of $1.7 million resulting from the previously discussed sale of our deep water Medusa field and our other offshore fields.

LOE for the nine months ended September 30, 2014 decreased by 9% to $14.9 million compared to $16.4 million for the same period of 2013. The decrease is primarily related to a $6.6 million decline in LOE resulting from the sale of our deep water Medusa field and our other offshore fields, partially offset by $5.1 million in costs related to the growth in Permian production and operations, including an increase in workover expenses associated with the impact of accelerated horizontal well activity on surrounding producing wells.

Production taxes

For the three months ended September 30, 2014, production taxes increased 127%, or $1.3 million, to $2.2 million compared to $1.0 million for the same period of 2013. Similarly, for the nine months ended September 30, 2014 compared to the same period of 2013, production taxes increased 190%, or $4.2 million, to $6.4 million. The increases were predominantly attributable to an increase in onshore production subject to these taxes accompanied by a decline in offshore production, resulting from the sale of our Gulf of Mexico position in 2013, which was exempt from production taxes.

Depreciation, depletion and amortization (“DD&A”)

For the three months ended September 30, 2014, DD&A increased 5% per BOE to $31.05 per BOE compared to $29.62 per BOE for the same period of 2013. This increase primarily relates to an increased depreciable base relative to estimated proved reserves and an immaterial prior period adjustment. During the third quarter, the depreciable base included an increase related to a portion of the carrying value of our Northern Midland acreage that was previously classified as unevaluated properties and increases related to capitalized costs related to our efforts on acquisitions, development, exploration, and exploitation of onshore oil and natural gas reserves in the Permian Basin.

For the nine months ended September 30, 2014, DD&A decreased 12% per BOE to $27.76 per BOE compared to $31.70 per BOE for the same period of 2013. The decrease is attributable to our increasing estimated proved reserves relative to our depreciable asset base, as a result of our efforts on acquisition, development, exploration, and exploitation of onshore oil and natural gas reserves in the Permian Basin.

General and administrative, net of amounts capitalized (“G&A”)

G&A for the three months ended September 30, 2014 decreased to $3.3 million compared to $5.8 million for the same period of 2013. The $2.6 million decrease primarily relates to a $3.4 million difference in the adjustment to the mark-to-market valuation of performance-based phantom stock incentive awards period over period, partially offset by an increase in employee-related expenses. Total G&A for the third quarter of 2014 included the following items:

- $0.1 million in non-recurring, cash expense related to a threatened proxy contest
- $1.5 million in non-cash gain related to the fair value adjustment of performance-based phantom stock incentive awards

G&A for the nine months ended September 30, 2014 increased to $23.7 million compared to $14.1 million for the same period of 2013. The $9.6 million increase primarily relates to a $4.7 million difference in the adjustment to the mark-to-market valuation of performance-based phantom stock incentive awards period over period, $3.9 million of non-recurring items as mentioned below and an increase in employee-related expenses. Total G&A for the period included $9.6 million of expense related to the following items:

- $1.4 million in non-recurring, cash expense related to a threatened proxy contest
- $2.5 million in non-recurring expenses (both non-cash and cash components) primarily related to the accelerated vesting of outstanding equity awards for early retirement of employees

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- $5.7 million in non-cash expense related to the fair value adjustment of performance-based phantom stock incentive awards

Accretion expense

Accretion expense related to our ARO decreased 56% and 61%, respectively, for the three and nine months ended September 30, 2014 compared to the same periods of 2013. Accretion expense correlates with the Company's ARO which was $6.4 million at September 30, 2014 versus $11.5 million at September 30, 2013. The reduction in ARO was primarily a result of the divestiture of our offshore fields in the fourth quarter of 2013. See Note 8 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Gain on sale of other property and equipment

See Note 10 in the Footnotes to the Financial Statements for a discussion of the gain on the sale of equipment.

Other Income and Expenses and Preferred Stock Dividends

(in thousands)	Three Months Ended September 30,			
	2014	2013	$ Change	% Change
Interest expense	$ 2,205	$ 1,417	$ 788	56%
Loss (gain) on derivative contracts	(9,944)	3,686	(13,630)	(370)%
Other income, net	(61)	(279)	218	(78)%
Income tax expense	7,161	456	6,705	1,470%
Equity in earnings of Medusa Spar LLC	—	17	(17)	(100)%
Preferred stock dividends	(1,974)	(1,974)	—	—%

	Nine Months Ended September 30,			
	2014	2013	$ Change	% Change
Interest expense	$ 5,007	$ 4,469	538	12%
Gain on early extinguishment of debt	(3,205)	—	(3,205)	100%
Loss (gain) on derivative contracts	(2,746)	2,123	(4,869)	(229)%
Other income, net	(203)	(368)	165	(45)%
Income tax expense	12,630	950	11,680	1,229%
Equity in earnings of Medusa Spar LLC	—	14	(14)	(100)%
Preferred stock dividends	(5,921)	(2,654)	(3,267)	123%

Interest expense

Interest expense incurred during the three months ended September 30, 2014 increased $0.8 million compared to the same period of 2013. The increase is primarily attributable to $2.5 million in expense related to additional draws on our Credit Facility and Second Lien Loan in 2014 compared to the corresponding period of the prior year, and a $0.6 million decrease in capitalized interest compared to the 2013 period, resulting from a lower average unevaluated property balance period over period. Offsetting the increase is a $2.3 million decrease in interest expense related to our Senior Notes following a $48.5 million partial redemption during the fourth quarter of 2013 and a full redemption of the remaining outstanding principal in April 2014.

Interest expense incurred during the nine months ended September 30, 2014 increased $0.5 million compared to the same period of 2013. The increase is primarily attributable to $4.5 million in expense related to additional draws on our Credit Facility and Second Lien Loan in 2014 compared to the corresponding period of the prior year, and a $1.7 million decrease in capitalized interest compared to the 2013 period, resulting from a lower average unevaluated property balance period over period. Offsetting the increase is a $5.7 million decrease in interest expense related to our Senior Notes following a $48.5 million partial redemption during the fourth quarter of 2013 and a full redemption of the remaining outstanding principal in April 2014.

Loss (gain) on derivative contracts

See Notes 5 and 6 in the Footnotes to the Financial Statements for a reconciliation of the components of the Company’s derivative contracts and disclosures related to derivative instruments including their composition and valuation.

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Income tax expense

See Note 7 in the Footnotes to the Financial Statements for a discussion of our effective tax rates for the periods presented above.

Preferred stock dividends

Preferred Stock dividends for the three and nine months ended September 30, 2014 remained the same and increased $3.3 million, respectively, compared to the same periods of 2013. We issued the Preferred Stock on May 30, 2013. Accordingly, the nine-month period ended September 30, 2014 reflects dividends for the entire period compared to approximately four months of dividends in the same period of 2013. Dividends reflect a 10% dividend rate and $79 million liquidation value. See Note 9 in the Footnotes to the Financial Statements for additional information.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk. The total volumes which we hedge through the use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 50% to 75% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices, in addition to modification of our capital spending plans related to operational activities and acquisitions.

As of October 31, 2014, we had commodity contracts covering approximately 69% and 76% of our expected oil and natural gas production for the remaining three months of 2014, respectively, based on the midpoint of publicly disclosed guidance as of November 5, 2014 and including the impact of derivative contracts established after September 30, 2014. Our actual production will vary from the amounts estimated, perhaps materially. See Note 5 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at September 30, 2014 and derivative contracts established subsequent to that date.

The Company may utilize fixed price swaps, which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales. Additionally, the Company may sell put options or call options in conjunction with a swap and use the proceeds to increase the fixed price received.

The Company may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counterparty receives the difference from the Company. Additionally, the Company may sell put options at a price lower than the floor price in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices.

The Company may purchase put options, which reduce the Company's exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company's derivative positions are designated as hedges for accounting purposes.

Interest rate risk

On September 30, 2014, the Company's debt consisted of $82.5 million related to its Second Lien Facility and $20.0 million related to its Credit Facility. The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under the Second Lien Loan and Credit Facility. As of September 30, 2014, the weighted average interest rate on our Credit Facility borrowings was 2.43% and the interest rate on our Second Lien Loan borrowings was 8.75%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $1.0 million based on the $102.5 million outstanding in the aggregate under the two facilities on September 30, 2014. The Company is also subject to market risk exposure going forward related to changes in interest rate for the New Second Lien Loan. See Note 4 to the Consolidated Financial Statements for more information on the Company's interest rates on debt.

Counterparty and customer credit risk

The Company's principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

The Company markets receivables from the sale of our oil and natural gas production to energy marketing companies. We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require any of our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At September 30, 2014 our receivables from the sale of our oil and natural gas production were approximately $17.3 million in total.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At September 30, 2014 our joint interest receivables were approximately $8.0 million.

The Company's oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. The counterparties on our derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional derivative instruments with these or other lenders under our Credit Facility, representing institutions with an investment grade ratings. We have existing International Swap Dealers Association Master Agreements ("ISDA Agreements") with our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

Item 4. Controls and Procedures

Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2014.

Changes in internal control over financial reporting. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

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Part II. Other Information

Item 1. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material effect on our financial position or results of operations.

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors disclosed in our 2013 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

None.

Item 5. Other Information

None.

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Item 6. Exhibits

The following exhibits are filed as part of this Form 10-Q.

Exhibit Number	Description
1.	Underwriting Agreements
1.1	Underwriting Agreement dated as of September 9, 2014, between Callon Petroleum Company and Johnson Rice & Company L.L.C. and Scotia Capital (USA) Inc. as representatives of the several underwriters named therein. (incorporated by reference to Exhibit 1.1 of the Company's Form 8-K filed on September 15, 2014)
3.	Articles of Incorporation and By-Laws
3.1	Certificate of Incorporation of the Company, as amended through January 17, 2014 (incorporated by reference to Exhibit 3.1 of the Company's Form 10-Q filed on August 6, 2014)
3.2	Certificate of Designation of Rights and Preferences of 10.0% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Form 8-A filed on May 23, 2013)
3.3	Bylaws of the Company (incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-4 filed August 4, 1994, Reg. No. 33-82408)
4.	Instruments defining the rights of security holders, including indentures
4.1	Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
4.2	

Form of Certificate representing the 10.0% Series A Cumulative Preferred Stock (incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-A filed on May 23, 2013)

10. Material Contracts

10.1 Operator Resignation and Transition Agreement, dated August 29, 2014 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed October 14, 2014)

10.2 Purchase and Sale Agreement, dated August 29, 2014 (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed October 14, 2014)

10.3 Purchase and Sale Agreement, dated August 29, 2014 (incorporated by reference to Exhibit 10.2 of the Company's Report on Form 8-K filed October 14, 2014)

10.4 Amendment to Revolving Credit Facility, dated October 8, 2014 (incorporated by reference to Exhibit 10.3 of the Company's Report on Form 8-K filed October 14, 2014)

10.5 $300 million secured second lien term loan facility, dated October 8, 2014 (incorporated by reference to Exhibit 10.4 of the Company's Report on Form 8-K filed October 14, 2014)

10.6 Inter-Creditor Agreement, dated October 8, 2014 (incorporated by reference to Exhibit 10.5 of the Company's Report on Form 8-K filed October 14, 2014)

31. Section 13a-14 Certifications

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. Section 1350 Certifications

32.1 Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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101.*	Interactive Data Files

* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

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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.

	Callon Petroleum Company	
Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	November 5, 2014
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	Senior Vice President, Chief Financial Officer and Treasurer	November 5, 2014