CALLON PETROLEUM CO
Form 10-Q
November 05, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM
10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For The Quarterly Period Ended September 30, 2015

OR

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ____________ to ____________

Commission File Number 001-14039

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 the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if 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

The Registrant had 66,287,148 shares of common stock outstanding as of October 30, 2015.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their 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, 2015 Unaudited	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,922	$ 968
Accounts receivable	39,385	30,198
Fair value of derivatives	16,763	27,850
Other current assets	1,410	1,441
Total current assets	59,480	60,457
Oil and natural gas properties, full cost accounting method:		
Evaluated properties	2,251,993	2,077,985
Less accumulated depreciation, depletion and amortization	(1,618,027)	(1,478,355)
Net oil and natural gas properties	633,966	599,630
Unevaluated properties	141,581	142,525
Total oil and natural gas properties	775,547	742,155
Other property and equipment, net	7,905	7,118
Restricted investments	3,305	3,810
Deferred tax asset	—	44,688
Deferred financing costs	15,858	18,200
Fair value of derivatives	2,203	—
Other assets, net	426	342
Total assets	$ 864,724	$ 876,770
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 76,162	$ 76,753
Accrued interest	6,066	5,993
Cash-settled restricted stock unit awards	8,025	3,856
Asset retirement obligations	827	4,747
Deferred tax liability	—	6,214
Fair value of derivatives	—	1,249
Total current liabilities	91,080	98,812
Senior secured revolving credit facility	99,000	35,000
Secured second lien term loan	300,000	300,000
Asset retirement obligations	3,856	1,927
Cash-settled restricted stock unit awards	3,487	7,175

Other long-term liabilities	220	121
Total liabilities	497,643	443,035
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 shares authorized; 66,279,074 and 55,225,288 shares outstanding, respectively	663	552
Capital in excess of par value	592,287	526,162
Accumulated deficit	(225,885)	(92,995)
Total stockholders' equity	367,081	433,735
Total liabilities and stockholders' equity	$ 864,724	$ 876,770

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,	
	2015	2014	2015	2014
Operating revenues:				
Oil sales	$ 30,582	$ 36,346	$ 94,584	$ 104,965
Natural gas sales	3,734	3,311	9,365	8,479
Total operating revenues	34,316	39,657	103,949	113,444
Operating expenses:				
Lease operating expenses	7,194	6,270	20,728	14,863
Production taxes	2,583	2,247	7,800	6,429
Depreciation, depletion and amortization	16,704	16,115	52,395	38,635
General and administrative	4,302	3,261	22,167	23,707
Accretion expense	142	202	485	603
Write-down of oil and natural gas properties	87,301	—	87,301	—
Rig termination fee	—	—	3,641	—
Gain on sale of other property and equipment	—	—	—	(1,080)
Total operating expenses	118,226	28,095	194,517	83,157
Income (loss) from operations	(83,910)	11,562	(90,568)	30,287
Other income:				
Interest expense	5,603	2,205	15,567	5,007
Gain on early extinguishment of debt	—	—	—	(3,205)
Gain on derivative contracts	(23,283)	(9,944)	(17,463)	(2,746)
Other income	(92)	(61)	(177)	(203)
Total other income	(17,772)	(7,800)	(2,073)	(1,147)
Income (loss) before income taxes	(66,138)	19,362	(88,495)	31,434
Income tax expense	45,667	7,161	38,474	12,630
Net income (loss)	(111,805)	12,201	(126,969)	18,804
Preferred stock dividends	(1,974)	(1,974)	(5,921)	(5,921)
Income (loss) available to common stockholders	$ (113,779)	$ 10,227	$ (132,890)	$ 12,883
Income (loss) per common share:				
Basic	$ (1.72)	$ 0.24	$ (2.10)	$ 0.31
Diluted	$ (1.72)	$ 0.23	$ (2.10)	$ 0.30
Shares used in computing income (loss) per common share:				
Basic	66,277	43,187	63,265	41,370
Diluted	66,277	44,211	63,265	42,510

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,	
	2015	2014
Cash flows from operating activities:		
Net income (loss)	$ (126,969)	$ 18,804
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depreciation, depletion and amortization	52,583	39,493
Write-down of oil and natural gas properties	87,301	—
Accretion expense	485	603
Amortization of non-cash debt related items	2,342	494
Amortization of deferred credit	—	(433)
Deferred income tax expense	38,474	12,630
Net loss (gain) on derivatives, net of settlements	7,635	(5,728)
Gain on sale of other property and equipment	—	(1,080)
Non-cash gain for early debt extinguishment	—	(3,205)
Non-cash expense (benefit) related to equity share-based awards	(300)	432
Change in the fair value of liability share-based awards	4,759	6,571
Payments to settle asset retirement obligations	(3,047)	(3,283)
Changes in current assets and liabilities:		
Accounts receivable	(7,278)	(8,016)
Other current assets	31	802
Current liabilities	6,455	3,449
Payments to settle vested liability share-based awards related to early retirements	(3,538)	(1,417)
Payments to settle vested liability share-based awards	(3,925)	(2,052)
Change in other long-term liabilities	100	—
Change in other assets, net	421	(367)
Net cash provided by operating activities	55,529	57,697
Cash flows from investing activities:		
Capital expenditures	(178,548)	(188,793)
Deposit on acquisition	—	(10,629)
Proceeds from sales of mineral interests and equipment	348	1,991
Net cash used in investing activities	(178,200)	(197,431)
Cash flows from financing activities:		
Borrowings on credit facility	130,000	200,000
Payments on credit facility	(66,000)	(169,610)
Payment of deferred financing costs	—	(3,068)
Issuance of common stock	65,546	122,514
Payment of preferred stock dividends	(5,921)	(5,921)

Net cash provided by financing activities	123,625	143,915
Net change in cash and cash equivalents	954	4,181
Balance, beginning of period	968	3,012
Balance, end of period	$ 1,922	$ 7,193

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

Callon Petroleum Company

Notes to the Consolidated Financial Statements

(All dollar amounts in thousands, except 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, onshore, oil and natural gas reserves in the Permian Basin in West Texas, and more specifically, the Midland Basin. The Company’s operations to date have been predominantly focused on horizontal drilling of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shale. Callon has assembled a multi-year inventory of potential horizontal well locations and intends 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.

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 Callon Petroleum 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, 2014. The balance sheet at December 31, 2014 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, 2015.

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. Certain prior year amounts have been reclassified to conform to current year presentation.

Recently issued accounting policies

In April 2015, the Financial Accounting Standards Board issued accounting standards update No. 2015-03, Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). The standard requires that the costs for issuing debt should appear on the balance sheet as direct reduction from the debt's carrying value. The guidance in ASU 2015-03 is effective for public entities for annual reporting periods beginning after December 15, 2015, including interim periods therein. Early adoption is permitted and is to be applied on retrospective basis. The Company is currently evaluating the method of adoption and impact this standard will have on its financial statements and related disclosures.

In August 2015, the FASB issued ASU No. 2015-15, Interest – Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ("ASU 2015-15"). ASU 2015-15 updates the accounting guidance included in ASU 2015-03 as a result of the June 18, 2015, Emerging Issues Task Force meeting, in which the SEC stated that the SEC staff would not object to an entity deferring and presenting costs related to revolving debt arrangements as an asset. 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

The Company uses the full cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as oil and gas properties. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases, other costs related to exploration and development activities, and site restoration, dismantlement and abandonment costs capitalized in accordance with asset retirement obligation accounting guidance. Costs capitalized also include any internal costs that are directly related to exploration and development activities, including salaries and benefits, but do not include any costs related to production, general corporate overhead or similar activities.

Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. At September 30, 2015, the prices used in determining the estimated future net cash flows from proved reserves were \$54.48 per barrel of oil and \$3.53 per Mcf of natural gas. For the period ended September 30, 2015, the Company recognized a write-down of oil and natural gas properties of \$87,301 as a result of the ceiling test limitation.

Note 3 - Acquisitions

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 "Central Midland Basin Acquisition") for an aggregate cash purchase price of \$210,205. The Company assumed operatorship of the properties on November 1, 2014, and acquired a 62% working interest (46.5% net revenue interest) in the Central Midland Basin Acquisition. The aggregate cash purchase price was funded with a combination of the net proceeds from an equity offering of \$122,450 and a portion of the net proceeds from borrowings under a secured second lien term loan.

The Central Midland Basin Acquisition was accounted for under the acquisition method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The following purchase price allocation is based on management's estimates of the fair value of the assets acquired and liabilities assumed. The following table summarizes the acquisition date fair values of the net assets acquired:

Oil and natural gas properties	$ 91,895
Unevaluated oil and natural gas properties	118,450
Asset retirement obligations	(140)
Net assets acquired	$ 210,205

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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)

The following unaudited summary pro forma financial information for the three and nine months 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 Central Midland Basin 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 Central Midland Basin Acquisition 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, 2014	Nine Months Ended September 30, 2014
Revenues	$ 48,037	$ 142,040
Income from operations	15,245	45,543
Income available to common stockholders	11,143	16,686
Net income per common share:		
Basic	$ 0.19	$ 0.30
Diluted	$ 0.19	$ 0.29

Note 4 - 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, 2015	2014	Nine Months Ended September 30, 2015	2014
Net income (loss)	$ (111,805)	$ 12,201	$ (126,969)	$ 18,804
Preferred stock dividends	(1,974)	(1,974)	(5,921)	(5,921)
Income (loss) available to common stockholders	$ (113,779)	$ 10,227	$ (132,890)	$ 12,883
Weighted average shares outstanding	66,277	43,187	63,265	41,370
Dilutive impact of restricted stock	—	1,024	—	1,140
Weighted average shares outstanding for diluted loss per share	66,277	44,211	63,265	42,510
Basic income (loss) per share	$ (1.72)	$ 0.24	$ (2.10)	$ 0.31
Diluted income (loss) per share	$ (1.72)	$ 0.23	$ (2.10)	$ 0.30
Stock options (a)	15	30	15	30
Restricted stock (a)	159	—	159	—

(a) Shares excluded from the diluted earnings per share calculation because their effect would be anti-dilutive.

Note 5 - Borrowings

The Company’s borrowings consisted of the following at:

	September 30, 2015	December 31, 2014

Principal components:		
Senior secured revolving credit facility	$ 99,000	$ 35,000
Secured second lien term loan	300,000	300,000
Total carrying value of borrowings	$ 399,000	$ 335,000

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, 2015, the Credit Facility's borrowing base was $250,000. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. Subsequent to September 30, 2015 the Credit Facility's borrowing base was increased to $300,000 following the lenders' regularly scheduled semi-annual redetermination process.

As of September 30, 2015, the balance outstanding on the Credit Facility was $99,000 with a weighted-average interest rate of 2.21%, 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.

Secured second lien term loan (the "Term Loan")

On October 8, 2014, the Company entered into the Term Loan with an aggregate amount of up to $300,000 and a maturity date of October 8, 2021. The Royal Bank of Canada is Administrative Agent, and participants include several institutional lenders. The Term Loan may be prepaid at the Company's option, subject to a prepayment premium. The prepayment amount (i) is 102% if the prepayment event occurs prior to October 8, 2016, (ii) is 101% if the prepayment event occurs on or after October 8, 2016 but before October 8, 2017, and (iii) is 100% for prepayments made on or after October 8, 2017. The Term Loan is secured by junior liens on properties mortgaged under the Credit Facility, subject to an intercreditor agreement.

As of September 30, 2015, the balance outstanding on the Term Loan was $300,000 with 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 Company can elect a LIBOR rate based on various tenors, and is currently incurring interest based on an underlying three-month LIBOR rate, which was last elected in October 2015.

Restrictive covenants

The Company’s Credit Facility and Term 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, 2015.

Note 6 - 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 7 for additional information regarding fair value.

The Company executes commodity derivative contracts under master agreements that have netting provisions that provide for offsetting assets against liabilities. 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.

(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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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 7 for additional information regarding fair value.

Derivatives not designated as hedging instruments

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	09/30/2015	12/31/2014	09/30/2015	12/31/2014	09/30/2015	12/31/2014
Natural gas	Current	Fair value of derivatives	$ 407	$ 1,262	$ —	$ (7)	$ 407	$ 1,255
Oil	Current	Fair value of derivatives	16,356	26,588	—	(1,242)	16,356	25,346
Oil	Non-current	Fair value of derivatives	2,203	—	—	—	2,203	—
	Totals		$ 18,966	$ 27,850	$ —	$ (1,249)	$ 18,966	$ 26,601

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 for the periods indicated:

	September 30, 2015		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$ 17,539	$ (776)	$ 16,763
Long-term assets: Fair value of derivatives	2,203	—	2,203
Current liabilities: Fair value of derivatives	$ (776)	$ 776	$ —

	December 31, 2014		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of derivatives	$ 27,850	$ —	$ 27,850
Current liabilities: Fair value of derivatives	$ (1,249)	$ —	$ (1,249)

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,	
	2015	2014	2015	2014
Oil derivatives				
Net gain (loss) on settlements	$ 9,399	$ (497)	$ 23,863	$ (2,838)
Net gain (loss) on fair value adjustments	13,758	10,351	(6,787)	5,805
Total gain (loss)	$ 23,157	$ 9,854	$ 17,076	$ 2,967
Natural gas derivatives				
Net gain (loss) on settlements	$ 390	$ 35	$ 1,235	$ (144)
Net gain (loss) on fair value adjustments	(264)	55	(848)	(77)
Total gain (loss)	$ 126	$ 90	$ 387	$ (221)

Total gain on derivative contracts	$ 23,283	$ 9,944	$ 17,463	$ 2,746

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, 2015:

	For the Three Months Ended				
Oil contracts	December 31, 2015	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Swap contracts (NYMEX):					
Total volume (MBbls)	442	182	182	184	184
Weighted average price per Bbl	$ 64.93	$ 58.23	$ 58.23	$ 58.23	$ 58.23
Swap contracts (Midland basis differentials):					
Volume (MBbls)	327	364	364	368	368
Weighted average price per Bbl	$ (2.38)	$ 0.17	$ 0.17	$ 0.17	$ 0.17
Collar contracts combined with short puts (WTI, three-way collar):					
Volume (MBbls)	—	182	182	184	184
Weighted average price per Bbl					
Ceiling (short call)	$ —	$ 65.00	$ 65.00	$ 65.00	$ 65.00
Floor (long put)	$ —	$ 55.00	$ 55.00	$ 55.00	$ 55.00
Short put	$ —	$ 40.33	$ 40.33	$ 40.33	$ 40.33

	For the Three Months Ended				
Natural gas contracts	December 31, 2015	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Collar contracts combined with short puts (three-way collar):					
Volume (BBtu)	161	—	—	—	—

Weighted average price per MMBtu					
Ceiling (short call)	$ 4.32	$ —	$ —	$ —	$ —
Floor (long put)	$ 3.85	$ —	$ —	$ —	$ —
Short put	$ 3.25	$ —	$ —	$ —	$ —
Swap contracts:					
Total volume (BBtu)	228	—	—	—	—
Weighted average price per MMBtu	$ 3.96	$ —	$ —	$ —	$ —
Short call contracts:					
Short call volume (BBtu)	111	—	—	—	—
Short call price per MMBtu	$ 5.00	$ —	$ —	$ —	$ —

Note 7 - Fair Value Measurements

The fair value hierarchy included in GAAP 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, and 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.

(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)

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 6 for additional information regarding the Company's derivative instruments.

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

Balance Sheet Presentation as of September 30, 2015	Classification	Level 1	Level 2	Level 3	Total
Fair value of derivatives	Current assets	$ —	$ 16,763	$ —	$ 16,763
Other assets, net	Long-term assets	—	2,203	—	2,203
Total net assets		$ —	$ 18,966	$ —	$ 18,966

Balance Sheet Presentation as of December 31, 2014	Classification	Level 1	Level 2	Level 3	Total
Fair value of derivatives	Current assets	$ —	$ 27,850	$ —	$ 27,850
Fair value of derivatives	Current liabilities	—	(1,249)	—	(1,249)
Total net assets		$ —	$ 26,601	$ —	$ 26,601

Note 8 - Income Taxes

The Company typically 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. As a result of the write-down of oil and natural gas properties discussed in Note 2, the Company has incurred a cumulative three year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the ability to realize its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance for a portion of the deferred tax asset. The valuation allowance was $68,818 as of September 30, 2015.

Note 9 - Asset Retirement Obligations

The table below summarizes the Company's asset retirement obligations activity for the nine months ended September 30, 2015:

Asset retirement obligations at January 1, 2015	$ 6,674
Accretion expense	485
Liabilities incurred	121
Liabilities settled	(2,923)
Revisions to estimate	326
Asset retirement obligations at end of period	4,683
Less: Current asset retirement obligations	(827)

Long-term asset retirement obligations at September 30, 2015	$ 3,856

Certain of the Company’s operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the consolidated balance sheet at September 30, 2015 as long-term restricted investments were $3,305. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company’s oil and natural gas properties.

Note 10 - 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. Preferred Stock dividends were $1,974 and $5,921 for the three and nine months ended September 30, 2015 and 2014, respectively.

The Preferred Stock has no stated maturity and is not 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 in cash, plus any accrued and unpaid dividends to the redemption date.

Following a change of control, as defined in the prospectus supplement, 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, 2015, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of $7.29 as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 6.9 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 March 13, 2015, the Company completed an underwritten public offering of 9,000,000 shares of its common stock at $6.55 per share, before underwriting discounts, and the exercise in full by the underwriters of their option to purchase 1,350,000 additional shares of common stock at $6.55 per share, before underwriting discounts. The Company received net proceeds of approximately $65,546, after the underwriting discounts and estimated offering costs.

Note 11 - Other

Operating leases

As of September 30, 2015, the Company had contracts for two horizontal drilling rigs (the "Cactus 1 Rig" and "Cactus 2 Rig"). The Cactus 1 Rig was initially contracted for a term of two years in April 2012. The Cactus 2 Rig was initially contracted for a term of two years in April 2014. The Cactus 2 Rig replaced a previously contracted horizontal drilling rig, which was cancelled in March 2014. In March 2015, the Company extended the terms of its Cactus 1 Rig and Cactus 2 Rig to end in July 2018 and August 2018, respectively. The rig lease agreements include early termination provisions that obligate the Company to reduced minimum rentals pursuant to a "standby" dayrate for the term of the agreement. These payments would be reduced assuming the lessor is able to re-charter the rig and staffing personnel to another lessee.

In March 2015, the Company decided to terminate its one-year contract for a vertical rig (effective April 2015) and is required to pay approximately $3,641 in reduced rental payments over the remainder of the lease term ending November 2015, unless the lessor is able to re-charter the rig to another lessee. This amount was recognized as rig termination fee on the consolidated statements of operations for the three and nine months ended September 30, 2015. As of September 30, 2015, the Company has paid $2,800 of the estimated $3,641 in reduced rental payments.

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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, 2014 (the "2014 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 2014 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 2014 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 operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity to date has been predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shale. 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 79% oil and 21% natural gas for the nine months ended September 30, 2015. On September 30, 2015, our acreage position in the Permian Basin was approximately 17,395 net acres. The Company no longer holds an acreage position in the Northern Midland Basin after selling 40 gross and net acres around a producing well and releasing all remaining undeveloped acreage in the Northern Midland Basin in 2015.

Commodity Prices

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 actions by OPEC and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and cost of the capital;
- the amount we are allowed to borrow under our credit facility; and
- the value of our oil and natural gas properties.

For the three months ended September 30, 2015, the average NYMEX price for a barrel of oil was $46.41 per Bbl, compared to $97.24 per Bbl for the same period of 2014. For the nine months ended September 30, 2015, the average

NYMEX price for a barrel of oil was $51.00 per Bbl compared to $99.66 per Bbl for the same period of 2014. The NYMEX price for a barrel of oil ranged from a low of $38.24 per Bbl to a high of $61.43 per Bbl for the nine months ended September 30, 2015.

For the three months ended September 30, 2015, the average NYMEX price for natural gas was $2.73 per MMBtu compared to approximately $3.95 per MMBtu for the same period in 2014. For the nine months ended September 30, 2015, the average NYMEX price for natural gas was $2.76 per MMBtu compared to $4.41 per MMBtu for the same period in 2014. The NYMEX price for natural gas ranged from a low of $2.49 per MMBtu to a high of $3.23 per MMBtu for the nine months ended September 30, 2015.

The Company uses the full cost method of accounting for its exploration and development activities. Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling). These rules generally require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling. For the period ended September 30, 2015, the Company recorded an $87.3 million write-down of oil and natural gas properties as a result of the ceiling test limitation driven primarily by the significant decrease in oil prices beginning in the fourth quarter of 2014. Based on

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prevailing commodity prices in the current environment, we expect to incur additional ceiling test write-downs in the future. However, we do not expect such prevailing commodity prices to have significant adverse effects on our proved oil and gas reserves. See Note 2 in the Footnotes to the Financial Statements for more information.

The table below presents results of the full cost ceiling test as of September 30, 2015, along with various pricing scenarios to demonstrate the sensitivity of our full cost ceiling to changes in 12-month average oil and natural gas prices. Prices do not include the impact of oil and natural gas derivative instruments. This sensitivity analysis is as of September 30, 2015 and, accordingly, does not consider drilling results, production, changes in oil and natural gas prices, and changes in future development and operating costs subsequent to September 30, 2015 that may require revisions to our proved reserve estimates and resulting estimated future net cash flows used in the full cost ceiling test.

	12-Month Average Prices		Excess (Deficit) of full cost ceiling over net capitalized costs	Change in excess (deficit) of full cost ceiling over net capitalized costs
Pricing Scenarios	Oil ($/Bbl)	Natural gas ($/Mcf)	(In millions)	(In millions)
September 30, 2015 Actual	$ 54.48	$ 3.53	$ (87,301)	$ —
Combined price sensitivity				
Oil and natural gas +10%	$ 59.93	$ 3.89	$ 33,020	$ 120,321
Oil and natural gas -10%	$ 49.03	$ 3.18	$ (207,737)	$ (120,436)
Oil price sensitivity				
Oil +10%	$ 59.93	$ 3.53	$ 20,080	$ 107,381
Oil -10%	$ 49.03	$ 3.53	$ (194,748)	$ (107,447)
Natural gas sensitivity				
Natural gas +10%	$ 54.48	$ 3.89	$ (74,322)	$ 12,979
Natural gas -10%	$ 54.48	$ 3.18	$ (100,292)	$ (12,991)

Operational Highlights

Our production grew 73% and 82% for the three and nine months ended September 30, 2015, respectively, compared to the same periods of 2014, increasing to 896 MBOE from 519 MBOE and 2,533 MBOE from 1,392 MBOE for the comparative three and nine months periods, respectively.

	Net Production (MBOE)			
	Three Months Ended September 30,			
	2015	2014	Change	% Change
Southern Midland Basin	613	393	220	56%
Central Midland Basin	283	123	160	130%
Northern Midland Basin	—	3	(3)	(100)%
Total	896	519	377	73%

	Net Production (MBOE)			
	Nine Months Ended September 30,			
	2015	2014	Change	% Change
Southern Midland Basin	1,601	1,080	521	48%
Central Midland Basin	931	297	634	213%
Northern Midland Basin	1	15	(14)	(93)%
Total	2,533	1,392	1,141	82%

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The following table sets forth productive wells as of September 30, 2015:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	348	259.9	—	—
Royalty interest	3	0.1	—	—
Total	351	260.0	—	—

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.

The following table summarizes the Company’s drilling activity in the Permian Basin for periods indicated:

	For the Three Months Ended September 30, 2015					
	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin horizontal wells	1	1.0	2	2.0	1	1.0
Central Midland Basin horizontal wells	7	4.1	7	5.0	2	0.4
Total Midland Basin horizontal wells	8	5.1	9	7.0	3	1.4

(a) Completions include wells drilled prior to the third quarter of 2015.

	For the Nine Months Ended September 30, 2015					
	Drilled		Completed (a)		Awaiting Completion	
	Gross	Net	Gross	Net	Gross	Net
Southern Midland Basin horizontal wells	12	11.8	14	13.8	1	1.0
Central Midland Basin horizontal wells	15	8.7	13	8.3	2	0.4
Central Midland Basin vertical wells	—	—	1	0.4	—	—
Total Midland Basin wells	27	20.5	28	22.5	3	1.4

(a) Completions include wells drilled prior to 2015.

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. In March 2015, we completed a common stock offering to raise additional capital, and we continue to evaluate other sources of capital to complement our cash flows from operations as we pursue our long-term growth plan in the Permian Basin.

Based upon current commodity price expectations for 2015, we believe that our cash flow from operations, proceeds from our March 2015 equity offering and borrowings under our Credit Facility and Term Loan will be sufficient to fund our operations for 2015, including working capital requirements. However, future cash flows are subject to a number of variables, including forecasted production volumes and commodity prices. We are the operator for 100% of our remaining 2015 capital program and, as a result, the amount and timing of a substantial portion of our planned capital expenditures is largely discretionary. Accordingly, we may determine it prudent to curtail drilling and completion operations due to capital constraints or reduced returns on investment as a result of commodity price weakness.

Cash and cash equivalents increased $0.9 million in the nine months ended September 30, 2015 to $1.9 million compared to $1.0 million at December 31, 2014.

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Liquidity and cash flow

	Nine Months Ended September 30,	
(dollars in millions)	2015	2014
Net cash provided by operating activities	$ 55.5	$ 57.7
Net cash used in investing activities	(178.2)	(197.4)
Net cash provided by financing activities	123.6	143.9
Net change in cash	$ 0.9	$ 4.2

Operating activities. For the nine months ended September 30, 2015, net cash provided by operating activities was $55.5 million compared to net cash provided by operating activities of $57.7 million for the same period in 2014. The decrease was predominantly attributable to a decline in oil revenues precipitated by depressed commodity prices, offset by gains on the settlement of derivative contracts and a 73% increase in oil production. Also contributing to the decrease were increases in lease operating expenses, production taxes, interest expense, nonrecurring early retirement expenses, and payments on cash-settled restricted stock unit ("RSU") awards. Production, realized prices, and operating expenses are discussed below in Results of Operations. See Notes 6 and 7 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, 2015, net cash used in investing activities was $178.2 million compared to $197.4 million for the same period in 2014. The $19.2 million decrease in cash used in investing activities was primarily attributable to a $10.6 million decrease in deposits on acquisitions for which there were none in the current period and a $10.3 million decrease in capital expenditures, offset by a $1.6 million decrease in proceeds resulting from the sale of mineral interests and equipment. The $10.3 million decrease in capital expenditures was driven by a decrease in acreage acquisition costs, a reduction in drilling and completion costs, and reductions in capitalized general and administrative costs allocated directly to exploration and development projects. Offsetting these costs was an increase in capital expenditures related to capitalized interest. General and administrative expenses and capitalized interest are discussed below in Results of Operations.

Capital expenditures, on a cash basis, include the following for the periods indicated (in millions):

	For the Nine Months Ended September 30,	
	2015	2014
Southern Midland Basin	$ 104.1	$ 127.7
Central Midland Basin	55.7	40.4
Northern Midland Basin	—	0.4
Total operational expenditures	159.8	168.5

Capitalized general and administrative costs allocated directly to

exploration and development projects	7.9	9.4
Capitalized interest	8.0	1.7
Total capitalized general and administrative and interest costs	15.9	11.1
Total operational expenditures inclusive of capitalized general and administrative and interest costs	175.7	179.6
Acquisitions	2.8	9.2
Total capital expenditures	$ 178.5	$ 188.8

Financing activities. For the nine months ended September 30, 2015, net cash provided by financing activities was $123.6 million compared to cash provided by financing activities of $143.9 million during the same period of 2014. Net cash provided by financing activities during the nine months ended September 30, 2015 included $65.5 million of net proceeds from the issuance of common stock and a net $64.0 million of borrowings on our Credit Facility. In addition, the Company paid approximately $5.9 million in preferred stock dividends. See Note 10 in the Footnotes to the Financial Statements for additional information about the Company's equity offering.

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Operational Capital Budget and Third Quarter Summary

In order to facilitate its tactical shift to the Central Midland area, the Company increased its operational capital budget to $180 million (on an accrual basis), with the increase primarily related to the facilities and infrastructure investment required to accommodate an increased level of activity. Callon also increased its drilling and completion budget to reflect longer completed lateral lengths, enhanced completion designs and non-consenting partner capital, offset in part by continued achieved reductions in well costs throughout the year. A reconciliation of the revised capital budget to the original plan is provided below (in millions):

	2015 Operational Capital Budget		
	Drilling and Completion	Facilities	Total
Original operational capital budget	$ 150.5	$ 12.0	$ 162.5
Enhanced completions/Longer laterals/Non-consents	7.5	—	7.5
Central Midland: Accelerated facilities investments	—	6.0	6.0
East Bloxom: Tank battery upgrade and repairs	—	4.0	4.0
Revised operational capital budget	$ 158.0	$ 22.0	$ 180.0

Operational capital expenditures on an accrual basis were $149.5 million for the nine months ended September 30, 2015.

For the nine months ended September 30, 2015, our horizontal drilling program was primarily focused on program development of established Upper and Lower Wolfcamp B zones and the Lower Spraberry zones, in both the Southern and Central Midland Basin with lateral lengths ranging from approximately 5,000 feet to 10,000 feet. We expect our remaining 2015 horizontal drilling program to be focused on the development of the Lower Spraberry zones in the Central Midland Basin with lateral lengths ranging from approximately 5,000 feet to 10,000 feet.

In addition to the operational capital expenditures above, we budgeted a total of $17.2 million for (i) capitalized general and administrative costs and (ii) certain retained plugging and abandonment costs related to divested Gulf of Mexico shelf assets.

We currently expect to fund our remaining 2015 capital program from cash flow from operations and borrowings under our Credit Facility.

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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,			
	2015	2014	Change	% Change
Net production:				
Oil (MBbls)	689	425	264	62%
Natural gas (MMcf)	1,239	565	674	119%
Total (MBOE)	896	519	377	73%
Average daily production (BOE/d)	9,739	5,641	4,098	73%
% oil (BOE basis)	77%	82%		
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 44.39	$ 85.52	$ (41.13)	(48)%
Oil (Bbl) (including impact of cash settled derivatives)	58.03	84.35	(26.32)	(31)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 3.01	$ 5.86	$ (2.85)	(49)%
Natural gas (Mcf) (including impact of cash settled derivatives)	3.33	5.92	(2.59)	(44)%
Total (BOE) (excluding impact of cash settled derivatives)	$ 38.30	$ 76.41	$ (38.11)	(50)%
Total (BOE) (including impact of cash settled derivatives)	49.22	75.52	(26.30)	(35)%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 30,582	$ 36,346	$ (5,764)	(16)%
Natural gas revenue	3,734	3,311	423	13%
Total	$ 34,316	$ 39,657	$ (5,341)	(13)%
Additional per BOE data:				
Sales price (excluding impact of cash settled derivatives)	$ 38.30	$ 76.41	$ (38.11)	(50)%
Lease operating expense	8.03	12.08	(4.05)	(34)%
Production taxes	2.88	4.33	(1.45)	(33)%
Operating margin	$ 27.39	$ 60.00	$ (32.61)	(54)%

	Nine Months Ended September 30,			
	2015	2014	Change	% Change
Net production:				
Oil (MBbls)	2,012	1,162	850	73%
Natural gas (MMcf)	3,124	1,381	1,743	126%
Total (MBOE)	2,533	1,392	1,141	82%
Average daily production (BOE/d)	9,278	5,099	4,179	82%
% oil (BOE basis)	79%	83%		
Average realized sales price:				
Oil (Bbl) (excluding impact of cash settled derivatives)	$ 47.01	$ 90.33	$ (43.32)	(48)%

Oil (Bbl) (including impact of cash settled derivatives)	58.87	87.89	(29.02)	(33)%
Natural gas (Mcf) (excluding impact of cash settled derivatives)	$ 3.00	$ 6.14	$ (3.14)	(51)%
Natural gas (Mcf) (including impact of cash settled derivatives)	3.39	6.04	(2.65)	(44)%
Total (BOE) (excluding impact of cash settled derivatives)	$ 41.04	$ 81.50	$ (40.46)	(50)%
Total (BOE) (including impact of cash settled derivatives)	50.95	79.35	(28.40)	(36)%
Oil and natural gas revenues (in thousands):				
Oil revenue	$ 94,584	$ 104,965	$ (10,381)	(10)%
Natural gas revenue	9,365	8,479	886	10%
Total	$ 103,949	$ 113,444	$ (9,495)	(8)%
Additional per BOE data:				
Sales price (excluding impact of cash settled derivatives)	$ 41.04	$ 81.50	$ (40.46)	(50)%
Lease operating expense	8.18	10.68	(2.50)	(23)%
Production taxes	3.08	4.62	(1.54)	(33)%
Operating margin	$ 29.78	$ 66.20	$ (36.42)	(55)%

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Revenues

The following table is 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, 2014	$ 36,346	$ 3,311	$ 39,657
Volume increase	22,519	3,946	26,465
Price decrease	(28,283)	(3,523)	(31,806)
Net increase (decrease)	(5,764)	423	(5,341)
Revenues for the three months ended September 30, 2015	$ 30,582	$ 3,734	$ 34,316

(in thousands)	Oil	Natural Gas	Total
Revenues for the nine months ended September 30, 2014	$ 104,965	$ 8,479	$ 113,444
Volume increase	76,759	10,705	87,464
Price decrease	(87,140)	(9,819)	(96,959)
Net increase (decrease)	(10,381)	886	(9,495)
Revenues for the nine months ended September 30, 2015	$ 94,584	$ 9,365	$ 103,949

Oil revenue

For the quarter ended September 30, 2015, oil revenues of $30.6 million decreased $5.8 million, or 16%, compared to revenues of $36.3 million for the same period of 2014. The decrease in oil revenue was primarily attributable to a 48% decrease in the average realized sales price offset by a 62% increase in production. The increase in production was primarily attributable to increased production from our Permian properties resulting from an increased number of producing wells from acquisitions and our horizontal drilling program, offset by normal and expected declines from our existing wells.

For the nine months ended September 30, 2015, oil revenues of $94.6 million decreased $10.4 million, or 10%, compared to revenues of $105.0 million for the same period of 2014. The decrease in oil revenue was primarily attributable to a 48% decrease in the average realized sales price offset by a 73% increase in production. The increase in production was primarily attributable to increased production from our Permian properties resulting from an increased number of producing wells from acquisitions and our horizontal drilling program, offset by normal and expected declines from our existing wells.

Natural gas revenue (including NGLs)

Natural gas revenues of $3.7 million increased $0.4 million, or 13%, during the three months ended September 30, 2015 compared to $3.3 million for the same period of 2014. The increase primarily relates to a 119% increase in natural gas volumes and was predominantly offset by a 49% decrease in the average price realized, which fell to $3.01 per Mcf from $5.86 per Mcf, reflecting decreases in both natural gas and natural gas liquids prices. The increase in production was primarily attributable to increased production from our Permian properties resulting from an increased number of producing wells as mentioned above.

Natural gas revenues of $9.4 million increased $0.9 million, or 10%, during the nine months ended September 30, 2015 compared to $8.5 million for the same period of 2014. The increase primarily relates to a 126% increase in natural gas volumes and was predominantly offset by a 51% decrease in the average price realized, which fell to $3.00 per Mcf from $6.14 per Mcf, reflecting decreases in both natural gas and natural gas liquids prices. The increase in production was primarily attributable to increased production from our Permian properties resulting from an increased number of producing wells as mentioned above.

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Operating Expenses

(in thousands, except per unit amounts)	Three Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
	2015	BOE	2014	BOE	$	%	$	%
Lease operating expenses	$ 7,194	$ 8.03	$ 6,270	$ 12.08	924	15%	(4.05)	(34)%
Production taxes	2,583	2.88	2,247	4.33	336	15%	(1.45)	(33)%
Depreciation, depletion and amortization	16,704	18.64	16,115	31.05	589	4%	(12.41)	(40)%
General and administrative	4,302	4.80	3,261	6.28	1,041	32%	(1.48)	(24)%
Accretion expense	142	0.16	202	0.39	(60)	(30)%	(0.23)	(59)%
Write-down of oil and natural gas properties	87,301	nm	—	—	87,301	nm	nm	nm

	Nine Months Ended September 30,							
		Per		Per	Total Change		BOE Change	
	2015	BOE	2014	BOE	$	%	$	%
Lease operating expenses	$ 20,728	$ 8.18	$ 14,863	$ 10.68	5,865	39%	(2.50)	(23)%
Production taxes	7,800	3.08	6,429	4.62	1,371	21%	(1.54)	(33)%
Depreciation, depletion and amortization	52,395	20.68	38,635	27.76	13,760	36%	(7.08)	(26)%
General and administrative	22,167	8.75	23,707	17.03	(1,540)	(6)%	(8.28)	(49)%
Accretion expense	485	0.19	603	0.43	(118)	(20)%	(0.24)	(56)%
Write-down of oil and natural gas properties	87,301	nm	—	—	87,301	nm	nm	nm
Rig termination fee	3,641	nm	—	—	3,641	nm	nm	nm
Gain on sale of other property and equipment	—	—	(1,080)	nm	1,080	nm	nm	nm

*nm = not meaningful

Lease operating expenses (“LOE”). These are daily costs incurred to extract oil and natural gas out of the ground, 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.

LOE for the three months ended September 30, 2015 increased by 15% to $7.2 million compared to $6.3 million for the same period of 2014 primarily due to the growth in Permian production and operations as a result of our acquisition efforts and horizontal drilling program. LOE per BOE for the three months ended September 30, 2015 was $8.03 per BOE compared to $12.08 per BOE for the same period of 2014, which was primarily attributable to a decrease in the number of workovers period over period. Higher production volumes also contributed to the 34% per BOE decrease for the three months ended September 30, 2015.

LOE for the nine months ended September 30, 2015 increased by 39% to $20.7 million compared to $14.9 million for the same period of 2014 primarily due to the growth in Permian production and operations as a result of our acquisition efforts and horizontal drilling program. LOE per BOE for the nine months ended September 30, 2015 was $8.18 per BOE compared to $10.68 per BOE for the same period of 2014, which was primarily attributable to a decrease in the number of workovers period over period. Higher production volumes also contributed to the 23% per BOE decrease for the nine months ended September 30, 2015.

Production taxes. Production taxes include severance and ad valorem taxes. In general, production taxes are directly related to commodity price changes; however, severance taxes are based upon current year commodity prices, whereas ad valorem taxes are based upon prior year commodity prices. 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. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

Production taxes for the three months ended September 30, 2015 increased by 15% to $2.6 million compared to $2.2 million for the same period of 2014. The increase was primarily due to an increase in ad valorem taxes attributable to a greater number of producing wells as a result of our acquisition efforts and horizontal drilling program. Offsetting this increase was a reduction in severance taxes as a result of the decline of oil and natural gas revenue as previously mentioned. On a per BOE basis, production taxes for the three months ended September 30, 2015 decreased by 33% compared to the same period of 2014.

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Production taxes for the nine months ended September 30, 2015 increased by 21% to $7.8 million compared to $6.4 million for the same period of 2014. The increase was primarily due to an increase in ad valorem taxes attributable to a greater number of producing wells as a result of our acquisition efforts and horizontal drilling program. Offsetting this increase was a reduction in severance taxes as a result of the decline of oil and natural gas revenue as previously mentioned. On a per BOE basis, production taxes for the nine months ended, September 30, 2015 decreased by 33% compared to the same period of 2014.

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

For the three and nine months ended September 30, 2015, DD&A increased 4% to $16.7 million and 36% to $52.4 million, respectively, over the comparative periods of 2014. These increases are primarily due to production increases of 73% and 82% for the respective periods as previously discussed. For the three months ended September 30, 2015, DD&A decreased 40% per BOE to $18.64 per BOE compared to $31.05 per BOE for the same period of 2014. Similarly, for the nine months ended September 30, 2015, DD&A decreased 26% per BOE to $20.68 per BOE compared to $27.76 per BOE for the same period of 2014. The decreases for both periods are attributable to our increased estimated proved reserves relative to our depreciable asset base.

General and administrative, net of amounts capitalized (“G&A”). These are costs incurred for overhead, including payroll and benefits for our corporate staff, severance and early retirement expenses, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, depreciation of corporate level assets, 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.

G&A for the three months ended September 30, 2015 increased to $4.3 million compared to $3.3 million for the same period of 2014. G&A expenses for the periods indicated include the following (in millions):

	For the Three Months Ended September 30,		
	2015	2014	% Change

			$ Change	
Recurring expenses				
G&A	$ 3.5	$ 4.0	$ (0.5)	(13)%
Share-based compensation	0.6	0.7	(0.1)	(14)%
Fair value adjustments of cash-settled RSU awards	0.1	(1.5)	1.6	107%
Non-recurring expenses				
Expense related to a threatened proxy contest	0.1	0.1	—	—%
Total G&A expenses	$ 4.3	$ 3.3	$ 1.0	30%

G&A for the nine months ended September 30, 2015 decreased to $22.2 million compared to $23.7 million for the same period of 2014. G&A expenses for the periods indicated include the following (in millions):

	For the Nine Months Ended September 30,			
	2015	2014	$ Change	% Change
Recurring expenses				
G&A	$ 11.2	$ 12.1	$ (0.9)	(8)%
Share-based compensation	1.6	2.0	(0.4)	(20)%
Fair value adjustments of cash-settled RSU awards	4.3	5.7	(1.4)	(24)%
Non-recurring expenses				
Early retirement expenses	3.6	1.4	2.2	157%
Early retirement expenses related to share-based compensation	1.1	1.1	—	—%
Expense related to a threatened proxy contest	0.4	1.4	(1.0)	(71)%
Total G&A expenses	$ 22.2	$ 23.7	$ (1.5)	(6)%

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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 ARO and reported as accretion expense within operating expenses in the consolidated statements of operations.

Accretion expense related to our ARO decreased 30% and 20% for the three and nine months ended September 30, 2015, respectively, compared to the same periods of 2014. Accretion expense generally correlates with the Company's ARO, which was $4.7 million at September 30, 2015 as compared to $6.4 million at September 30, 2014. See Note 9 in the Footnotes to the Financial Statements for additional information regarding the Company's ARO.

Write-down of oil and natural gas properties. During the third quarter of 2015, the Company recognized a write-down of oil and natural gas properties of $87.3 million as a result of the ceiling test limitation. No write-down was recognized during the comparable prior year periods. See Note 2 in the Footnotes to the Financial Statements for additional information. Based on prevailing commodity prices in the current environment, we expect to incur additional ceiling test write-downs in the future.

Rig termination fee. During the first quarter of 2015, the Company recognized $3.6 million in expense related to the early termination of the contract for its vertical rig. See Note 11 in the Footnotes to the Financial Statements for additional information.

Gain on sale of other property and equipment. During 2014, the Company entered into an agreement to sell certain specialized deep water equipment that resulted in a gain on the sale of other property and equipment of $1.1 million.

Other Income and Expenses and Preferred Stock Dividends

(in thousands)	Three Months Ended September 30,			
	2015	2014	$ Change	% Change
Interest expense	$ 5,603	$ 2,205	$ 3,398	154%
Gain on derivative contracts	(23,283)	(9,944)	(13,339)	134%
Other income	(92)	(61)	(31)	51%
Total	$ (17,772)	$ (7,800)		
Income tax expense	$ 45,667	$ 7,161	$ 38,506	538%
Preferred stock dividends	(1,974)	(1,974)	—	—

	Nine Months Ended September 30,			
	2015	2014	$ Change	% Change
Interest expense	$ 15,567	$ 5,007	$ 10,560	211%
Gain on early extinguishment of debt	—	(3,205)	3,205	(100)%
Gain on derivative contracts	(17,463)	(2,746)	(14,717)	536%
Other income, net	(177)	(203)	26	(13)%
Total	$ (2,073)	$ (1,147)		
Income tax expense	$ 38,474	$ 12,630	$ 25,844	205%
Preferred stock dividends	(5,921)	(5,921)	—	—%

Interest expense. Interest expense incurred during the three months ended September 30, 2015 increased $3.4 million compared to the same period of 2014. The increase is primarily attributable to $5.3 million in expense related to a higher outstanding debt balance in 2015 compared to the corresponding period of the prior year. Offsetting the increase is a $1.9 million increase in capitalized interest compared to the 2014 period, resulting from a higher average unevaluated property balance for the three months ended, September 30, 2015 as compared to the same period of 2014.

Interest expense incurred during the nine months ended September 30, 2015 increased $10.6 million compared to the same period of 2014. The increase is primarily attributable to $18.1 million in expense related to a higher outstanding debt balance in 2015 compared to the corresponding period of the prior year. Offsetting the increase is a $6.2 million increase in capitalized interest compared to the 2014 period, resulting from a higher average unevaluated property balance for the nine months ended, September 30, 2015 as

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compared to the same period of 2014, and a $1.3 million decrease in interest expense related to the full redemption of our Senior Notes in April 2014.

Gain on early extinguishment of debt. During April 2014, the Company completed a full redemption of the remaining $53.3 million carrying value of its outstanding Senior Notes. The carrying value included $48.5 million of principal value and $4.8 million of unamortized deferred credit. The Company recognized a net $3.2 million gain on early extinguishment of debt, comprised of the recognition of $4.8 million in deferred credit, offset by $1.6 million of redemption expenses.

Gain on derivative contracts. For the three and nine months ended September 30, 2015, the net gain on derivative contracts was $23.3 million and $17.5 million, respectively, compared to a $9.9 million and $2.7 million net gain for the same periods of 2014, respectively. See Notes 6 and 7 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.

Income tax expense. The Company had an income tax expense of $45.7 million for the three months ended September 30, 2015 compared to an income tax expense of $7.2 million for the same period of 2014. Similarly, the Company had an income tax expense of $38.5 million for the nine months ended September 30, 2015 compared to an income tax expense of $12.6 million for the same period of 2014. The increase in income tax expense is primarily related to the establishment of a valuation allowance of $68.8 million in the third quarter of 2015 and the difference in the amount of income (loss) before income taxes between periods. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends for the three and nine months ended September 30, 2015 were consistent with the same periods of 2014. Dividends reflect a 10% dividend rate and $78.9 million liquidation value. See Note 10 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, related both to NYMEX benchmark prices and regional basis differentials. 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 30, 2015, we had commodity hedging contracts linked to NYMEX benchmark pricing, covering approximately 60% and 38% of our expected oil and natural gas production, respectively, for the fourth quarter of 2015, based on the midpoint of publicly disclosed guidance as of November 4, 2015. In addition, we had commodity hedging contracts linked to Midland WTI basis differentials relative to Cushing covering approximately 44% of our expected oil production for the fourth quarter of 2015, based on the midpoint of publicly disclosed oil production guidance as of November 4, 2015. Our actual production may vary from the amounts estimated, perhaps materially. See Note 6 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at September 30, 2015 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, 2015, the Company's debt consisted of $300.0 million related to its Term Loan and $99.0 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 Term Loan and Credit Facility. As of September 30, 2015, the weighted average interest rate on our Credit Facility borrowings was 2.21% and the interest rate on our Term Loan borrowings was 8.50%. An increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $4.0 million based on the $399.0 million outstanding in the aggregate under the two facilities on September 30, 2015. The Company is also subject to market risk exposure related to changes

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in the underlying LIBOR-based interest rate used for the Term Loan to the extent that available LIBOR election options exceed the 1.0% floor rate. See Note 5 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 its 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, 2015 our receivables from the sale of our oil and natural gas production were approximately $18.2 million.

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, 2015 our joint interest receivables were approximately $17.6 million.

The Company's oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Most of 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, 2015.

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.

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 2014 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

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
3.	Articles of Incorporation and By-Laws
3.1 (a)	Certificate of Incorporation of the Company, as amended through May 20, 2015
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 (a)	First Amendment to the Callon Petroleum Company 2011 Omnibus Incentive Plan

31. Section 13a-14 Certifications

31.1 (a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 (a) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32. Section 1350 Certifications

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

101. (c) Interactive Data Files

(a) Filed herewith.
(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.
(c) Pursuant to Rule 406T of Regulation S-T, these interactive data files are being furnished herewith and are not deemed filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, 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 4, 2015
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	Senior Vice President, Chief Financial Officer and Treasurer	November 4, 2015