CALLON PETROLEUM CO
Form 10-Q
November 07, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

x	Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934	
	For the quarterly period ended:	September 30, 2013
	or	
o	Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934	
	For the transition period from:	____________ to _____________

Commission File Number 001-14039
CALLON PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

Delaware	64-0844345
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi	39120
(Address of principal executive offices)	(Zip Code)

601-442-1601
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

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

As of November 1, 2013 there were outstanding 40,345,456 shares of the Registrant's common stock, par value $0.01 per share.

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Part I. Financial Information
Item I. Financial Statements
Callon Petroleum Company
Consolidated Balance Sheets
(in thousands, except per share data)

	September 30, 2013	December 31, 2012
ASSETS	Unaudited	
Current assets:		
Cash and cash equivalents	$869	$1,139
Accounts receivable	20,072	15,608
Fair market value of derivatives	—	1,674
Deferred tax asset	3,323	—
Other current assets	1,738	1,502
Total current assets	26,002	19,923
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,634,151	1,497,010
Less accumulated depreciation, depletion and amortization	(1,329,866)	(1,296,265)
Net oil and natural gas properties	304,285	200,745
Unevaluated properties excluded from amortization	50,540	68,776
Total oil and natural gas properties	354,825	269,521
Other property and equipment, net	10,635	10,058
Restricted investments	3,800	3,798
Investment in Medusa Spar LLC	7,776	8,568
Deferred tax asset	60,198	64,383
Other assets, net	4,205	1,922
Total assets	$467,441	$378,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$49,384	$36,016
Asset retirement obligations	6,002	2,336
Fair market value of derivatives	1,139	125
Total current liabilities	56,525	38,477
13% Senior Notes:		
Principal outstanding	96,961	96,961
Deferred credit, net of accumulated amortization of $20,248 and $17,800, respectively	11,259	13,707
Total 13% Senior Notes	108,220	110,668
Senior secured revolving credit facility	17,000	10,000
Asset retirement obligations	5,505	10,965
Other long-term liabilities	3,579	2,092
Total liabilities	190,829	172,202
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500 shares authorized: 1,579 and 0 shares	16	—

outstanding, respectively		
Common stock, $0.01 par value, 60,000 shares authorized; 40,328 and 39,801 shares outstanding, respectively	405	398
Capital in excess of par value	400,348	328,116
Retained deficit	(124,157)	(122,543)
Total stockholders' equity	276,612	205,971
Total liabilities and stockholders' equity	$467,441	$378,173

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,	
	2013	2012	2013	2012
Operating revenues:				
Crude oil sales	$27,014	$24,061	$65,615	$71,883
Natural gas sales	3,783	3,341	10,483	10,174
Total operating revenues	30,797	27,402	76,098	82,057
Operating expenses:				
Lease operating expenses	5,270	5,203	16,412	18,687
Production taxes	991	656	2,217	1,778
Depreciation, depletion and amortization	11,907	11,965	33,603	35,998
General and administrative	5,826	6,441	14,110	15,846
Accretion expense	458	574	1,556	1,709
Total operating expenses	24,452	24,839	67,898	74,018
Income from operations	6,345	2,563	8,200	8,039
Other (income) expenses:				
Interest expense	1,417	2,135	4,469	7,096
Gain on early extinguishment of debt	—	—	—	(1,366)
Loss (gain) on derivative contracts	3,686	1,598	2,123	(1,977)
Other (income) expense, net	(279)	237	(368)	(224)
Total other (income) expenses, net	4,824	3,970	6,224	3,529
Income (loss) before income taxes	1,521	(1,407)	1,976	4,510
Income tax expense (benefit)	456	(246)	950	1,508
Income (loss) before equity in earnings of Medusa Spar LLC	1,065	(1,161)	1,026	3,002
Equity in earnings of Medusa Spar LLC	17	56	14	180
Net income (loss)	1,082	(1,105)	1,040	3,182
Preferred stock dividends	(1,974)	—	(2,654)	—
Net income (loss) available to common shareholders	$(892)	$(1,105)	$(1,614)	$3,182
Net income (loss) per common share:				
Basic	$(0.02)	$(0.03)	$(0.04)	$0.08
Diluted	$(0.02)	$(0.03)	$(0.04)	$0.08
Shares used in computing net income (loss) per common share:				
Basic	40,321	39,575	40,064	39,441
Diluted	40,321	39,575	40,064	40,243

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

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Callon Petroleum Company
Consolidated Statements of Comprehensive Income (Loss)
(Unaudited; in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss)	$1,082	$(1,105)	$1,040	$3,182
Other comprehensive (loss) income:				
Change in fair value of derivatives designated as hedges, net of tax (See Note 5)	—	(1,268)	—	(1,345)
Comprehensive income (loss)	1,082	(2,373)	1,040	1,837
Preferred stock dividends	(1,974)	—	(2,654)	—
Comprehensive income (loss) available to common shareholders	$(892)	$(2,373)	$(1,614)	$1,837

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, 2013	2012
Cash flows from operating activities:		
Net income	$1,040	$3,182
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	34,668	37,005
Accretion expense	1,556	1,709
Amortization of non-cash debt related items	348	293
Amortization of deferred credit	(2,448)	(2,304)
Non-cash gain on early extinguishment of debt	—	(1,366)
Equity in earnings of Medusa Spar LLC	(14)	(180)
Deferred income tax expense	950	1,508
Unrealized loss (gain) on derivative contracts	2,929	(2,017)
Non-cash expense related to equity share-based awards	1,335	752
Change in the fair value of liability share-based awards	1,076	2,611
Payments to settle asset retirement obligations	(701)	(1,136)
Changes in current assets and liabilities:		
Accounts receivable	(3,455)	(1,260)
Other current assets	(236)	244
Current liabilities	1,969	4,965
Payments to settle vested liability share-based awards	(239)	(1,462)
Change in natural gas balancing receivable	(206)	(96)
Change in natural gas balancing payable	(52)	(152)
Change in other long-term liabilities	(206)	—
Change in other assets, net	(3,100)	(911)
Cash provided by operating activities	$35,214	$41,385
Cash flows from investing activities:		
Capital expenditures	(101,067)	(115,401)
Acquisition	(11,000)	—
Proceeds from sale of mineral interest and equipment	1,389	526
Distribution from Medusa Spar LLC	813	1,423
Cash used in investing activities	$(109,865)	$(113,452)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	48,000	43,000
Payments on senior secured revolving credit facility	(41,000)	(3,000)
Redemption of 13% senior notes	—	(10,225)
Issuance of preferred stock	70,035	—
Payment of preferred stock dividends	(2,654)	—
Taxes paid related to exercise of employee stock options	—	(18)
Cash provided by financing activities	$74,381	$29,757
Net change in cash and cash equivalents	(270)	(42,310)
Beginning of period cash and cash equivalents	1,139	43,795

End of period cash and cash equivalents	$869	$1,485

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

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Callon Petroleum Company
Notes to the Consolidated Financial Statements
(Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.)

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3.	Earnings Per Share	8.	Asset Retirement Obligations
4.	Borrowings	9.	Equity Transaction
5.	Derivative Instruments and Hedging Activities		

Note 1 - Description of Business and Basis of Presentation

Description of business

Callon Petroleum Company is an independent crude oil and natural gas company established in 1950, which has been focused on building reserves and production both onshore and offshore through efficient operations and low finding and development costs. In 2009, we began to shift our operational focus from exploration in the Gulf of Mexico to building an onshore asset portfolio in order to provide a multi-year, low-risk drilling program in both crude oil and natural gas basins. A significant portion of this onshore transition has been funded by reinvesting the cash flows from the Company’s Gulf of Mexico properties. In the fourth quarter of 2012, we monetized our interest in the deepwater Habanero field in order to accelerate development of our onshore properties. In October 2013, we entered into an agreement to sell our interest in our remaining deepwater property, the Medusa field, the Company’s interest in the Medusa Spar facility and substantially all remaining offshore shelf properties. This transaction will complete our long-term goal of becoming an onshore operator upon closing with an asset base concentrated in the Permian Basin.

Basis of presentation

Unless otherwise indicated, all amounts included within the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

The interim consolidated financial statements of the Company have been prepared in accordance with (1) accounting principles generally accepted in the United States (“US GAAP”), (2) the Securities and Exchange Commission’s instructions to Quarterly Report on Form 10-Q and (3) Rule 10-01 of Regulation S-X, and include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company (“CPOC”). CPOC also has subsidiaries, namely Callon Offshore Production, Inc., and Mississippi Marketing, Inc.

These interim consolidated financial statements should be read in conjunction with the Company’s Annual Report on Form 10-K for the year ended December 31, 2012. The balance sheet at December 31, 2012 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, 2013.

In the opinion of management, the accompanying unaudited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account and transaction eliminations, necessary to present fairly the Company’s financial position, the results of its operations and its cash flows for the periods indicated. When necessary to ensure consistent presentation, certain prior year amounts may be reclassified. To the extent the amounts reclassified are material, we have either footnoted them within the Company's disclosures or have discussed the reclassifications within this footnote.

New accounting standard

In February 2013, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) that clarified the reclassification requirements from accumulated other comprehensive income to net income. This ASU requires disclosure of amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present either on the face of the financial statements or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount is reclassified in its entirety to net income in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to the related note on the face of the financial statements for additional information. Callon adopted this guidance effective January 1, 2013, which did not have a material impact on its financial statements.

Note 2 - Property Disclosures and Operating Leases

In April 2012, the Company took delivery of a drilling rig for a two-year term to support its horizontal drilling program in the Permian Basin. On August 1, 2013, the Company contracted an additional horizontal drilling rig for a one-year term. Lease cost recorded during the three and nine months ended September 30, 2013 was $3,874 and $8,425, respectively. Lease payments will approximate $12,601 in 2013 (with $4,176 remaining at September 30, 2013) and $6,941 in 2014. The agreements include early termination provisions that would reduce the minimum rentals under the agreement, assuming the lessor is unable to re-charter the rig and staffing personnel to another lessee, to $2,760 in 2013 and $4,530 in 2014.

On June 1, 2013, the Company acquired approximately 2,468 gross (2,186 net) acres in Reagan and Upton Counties, Texas, which is located in the southern portion of the Midland Basin and which is prospective for both horizontal and vertical drilling. The acquisition also included seven gross vertical wells and 1,051 barrels of oil equivalent proved reserves. The purchase price of $11,000 was funded using a portion of the proceeds from the preferred stock offering (discussed in Note 9).

Subsequent Event - Offshore Asset Sale

On October 17, 2013, the Company executed a purchase and sale agreement with W&T Offshore, Inc. (“W&T”), an unrelated third-party, pursuant to which W&T agreed to acquire our 15.0% working interest in the Medusa field (Mississippi Canyon blocks 582 and 538), our 10.0% membership interest in Medusa Spar LLC, and substantially all of our remaining Gulf of Mexico shelf properties for net cash consideration of approximately $100,000 before customary purchase price adjustments. W&T paid a deposit of $2,000, which will be applied to the purchase price. On November 5, 2013, the parties closed on a portion of the transaction for which the Company received $76,400 in proceeds. The remainder of the transaction is expected to close with adjusted proceeds of approximately $11,500 on or before November 30, 2013. The final closing of the transaction is subject to satisfaction of customary closing conditions and delivery of the total purchase price subject to adjustment for an acquisition effective date of July 1, 2013.

Also in October of 2013, Callon entered into an agreement to sell its 69% interest in the Swan Lake field for $2,000. This field includes 429 net acres and produced approximately 173 Mcf per day during the three months ended September 30, 2013. This is the Company’s only field in the Haynesville shale.

Footnotes to the Financial Statements
Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

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Note 3 - Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income (loss)	$1,082	$(1,105)	$1,040	$3,182
Preferred stock dividends	(1,974)	—	(2,654)	—
(a) Net income (loss) available to common shareholders	(892)	(1,105)	(1,614)	3,182
(b) Weighted average shares outstanding	40,321	39,575	40,064	39,441
Dilutive impact of stock options	—	—	—	10
Dilutive impact of restricted stock	—	—	—	792
(c) Weighted average shares outstanding for diluted net income (loss) per share	40,321	39,575	40,064	40,243
Basic net income (loss) per share (a/b)	$(0.02)	$(0.03)	$(0.04)	$0.08
Diluted net income (loss) per share (a/c)	$(0.02)	$(0.03)	$(0.04)	$0.08
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	52	52	52	52
Restricted stock	239	105	239	105

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	September 30, 2013	December 31, 2012
Principal components:		
Credit Facility	$17,000	$10,000
13% Senior Notes due 2016, principal	96,961	96,961
Total principal outstanding	113,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	11,259	13,707
Total carrying value of borrowings	$125,220	$120,668

Senior Secured Revolving Credit Facility (the “Credit Facility”)

As of September 30, 2013, the Company’s $200,000 Credit Facility had an associated borrowing base of $75,000 with a maturity date of March 15, 2016. In November 2013, the Credit Facility’s borrowing base was increased to $83,000 following a review of the Company’s reserve base, pro forma for the sale of the Gulf of Mexico properties discussed in Note 2, and is contingent upon the repayment of 50% of the outstanding principal of the Senior Notes. To the extent the Company elects not to redeem the 13% Senior Notes before December 20, 2013, the borrowing base would be reduced by an amount equal to 25% of the aggregate principal balance of the Senior Notes outstanding on December 20, 2013 in excess of $48,000. Regions Bank serves as the administrative agent for the Credit Facility, which also includes Citibank, NA, IberiaBank, Whitney Bank and OneWest Bank, FSB as participating lenders. Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The Credit Facility is secured by mortgages covering the Company's major producing fields.

On May 10, 2013, the Company entered into the second amendment to our Fourth Amended and Restated Credit Agreement that allows the Company to pay quarterly Senior Unsecured Debt and Preferred Equity dividends of up to $5,500 per quarter, so long

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as the Company is not in default under the Credit Facility. The amendment became effective with the receipt of the cash proceeds from the preferred equity offering discussed in Note 9.

As of September 30, 2013, the balance outstanding on the Credit Facility was $17,000 with an interest rate of 2.7%, calculated as the London Interbank Offered Rate ("LIBOR") plus a tiered rate ranging from 2.5% to 3.0%, which is determined by utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly.

13% Senior Notes due 2016 ("Senior Notes") and Deferred Credit

Interest on the Senior Notes is payable on the last day of each quarter. Certain of the Company's subsidiaries guarantee the Company's obligations under the unsecured Senior Notes. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations, and any subsidiaries of the parent company other than the subsidiary guarantors are minor. Upon issuing the Senior Notes in November 2009, the Company recorded as a deferred credit the $31,507 difference between the adjusted carrying amount of the Senior Notes that were exchanged and the principal of the Senior Notes. This deferred credit is being amortized as a reduction of interest expense over the life of the Senior Notes at an 8.5% effective interest rate. The following table summarizes the Company's deferred credit balance:

Gross Carrying Amount	Accumulated Amortization at 9/30/2013	Carrying Value at 9/30/2013	Amortization Recorded during Current Year as a Reduction of Interest Expense	Estimated Amortization to be Recorded during the Remainder of the Current Year
$31,507	$20,248	$11,259	$2,448	$851

Restrictive Covenants

The indentures governing our Senior Notes and the Company's Credit Facility contain various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at September 30, 2013.

Note 5 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in realized crude oil and natural gas prices for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its crude oil and natural gas production. The Company primarily utilizes collars, put and call options and swap derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative purposes.

Counterparty risk and offsetting

The use of derivative transactions exposes the Company to the risk that a counterparty will be unable to meet its commitments. To manage this risk, the Company's established counterparties for commodity derivative instruments include a large, well-known financial institution and a large, well-known oil and gas company. 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. Counterparty credit risk is considered when determining a derivative instruments' fair value; See Note 6 for additional information.

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

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

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Financial statement presentation and settlements

In the first quarter of 2013, the Company monetized the remaining portion (covering the period Feb13-Dec13) of its 2013 crude oil collar positions of 40 Bbls per month. The proceeds from this transaction, combined with the proceeds from the sale of the below listed put for 30 Bbls per month, were used to finance the uplift in the crude oil swap for the period Feb13-Dec13.

Listed in the table below are the outstanding crude oil and natural gas derivative contracts as of September 30, 2013:

Commodity	Instrument	Average Notional Volumes per Month	Quantity Type	Put/Call Price	Fixed-Price Swap	Period	Designation under ASC 815
Natural gas	Swap	91	MMbtu	n/a	$3.52	Oct13 - Dec13	Not Designated
Natural gas	Put Option	91	MMbtu	$3.00	n/a	Oct13 - Dec13	Not Designated
Crude oil	Swap	40	Bbls	n/a	$101.30	Oct13 - Dec13	Not Designated
Natural gas	Call Option	38	MMbtu	$4.75	n/a	Jan14 - Dec14	Not Designated
Crude oil	Swap	30	Bbls	n/a	$93.35	Jan14 - Dec14	Not Designated
Crude oil	Put Option	30	Bbls	$70.00	n/a	Jan14 - Dec14	Not Designated
Crude oil	Swap	18	Bbls	n/a	$102.08	Oct13 - Dec13	Not Designated
Crude oil	Swap	9	Bbls	n/a	$94.58	Jan14 - Dec14	Not Designated

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 New York Mercantile Exchange ("NYMEX") price. The fair value of the Company's derivative instruments, depending on the type of instruments, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. See Note 6 for additional information regarding fair value.

The following table reflects the fair values of the Company's derivative instruments for the periods presented (none of which were designated as hedging instruments under ASC 815):

	Balance Sheet Presentation		Asset Fair Value		Liability Fair Value		Net Derivative Fair Value	
Commodity	Classification	Line Description	09/30/13	12/31/12	09/30/13	12/31/12	09/30/13	12/31/12
Natural gas	Current	Fair market value of derivatives	$—	$—	$(45)	$(125)	$(45)	$(125)
Natural gas	Non-current	Other long-term liabilities	—	—	(18)	(116)	(18)	(116)
Crude oil	Current	Fair market value of derivatives	—	1,674	(1,094)	—	(1,094)	1,674

Crude oil	Non-current	Other long-term assets	36	250	—	—	36	250
	Totals		$36	$1,924	$(1,157)	$(241)	$(1,121)	$1,683

The Company’s derivative contracts are subject to netting arrangements and, being representative of the way in which the contracts settle, are presented in the balance sheet at their fair values on a net basis based on the underlying commodity being hedged. The following presents the impact of this presentation to the Company’s recognized assets and liabilities at September 30, 2013:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of hedging contracts	$96	$(96)	$—
Long-term assets: Fair value of hedging contracts	155	(119)	36
Current liabilities: Fair value of hedging contracts	(1,235)	96	(1,139)
Long-term liabilities: Fair value of hedging contracts	(137)	119	(18)

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

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Derivatives not designated as hedging instruments

As discussed in the Company's Form 10-K for the year ended December 31, 2012, the Company elected not to designate as an accounting hedge under FASB ASC 815 any of its derivative contracts executed subsequent to December 31, 2011, nor does it expect to designate future derivative contracts. Derivative contracts not designated as accounting hedges are carried at fair value on the balance sheet with both realized and unrealized (i.e. mark-to-market) gains or losses recorded on the statement of operations as a component of the Company's other income and expenses.

For the periods indicated, the Company recorded the following related to its derivative instruments that were not designated as accounting hedges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Natural gas derivatives				
Realized gain (loss), net	$(16)	$—	$(123)	$—
Unrealized gain (loss), net	81	(205)	178	(536)
Sub-total gain (loss), net	$65	$(205)	$55	$(536)
Crude oil derivatives				
Realized gain (loss), net	$(618)	$—	$804	
Unrealized gain (loss), net	(3,133)	(1,393)	(2,982)	2,513
Sub-total gain (loss), net	$(3,751)	$(1,393)	$(2,178)	$2,513
Total gain (loss) on derivative instruments, net	$(3,686)	$(1,598)	$(2,123)	$1,977

Derivatives designated as hedging instruments

As previously discussed, the Company elected to discontinue hedge accounting at the start of 2012, though certain of the Company's crude oil derivative contracts designated as cash flow hedges were executed in prior periods and were in effect during 2012. Consequently, these designated contracts were recorded at fair market value with the effective portion of the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity. The cash settlements on contracts for future production were recorded as an increase or decrease in crude oil revenues. Both changes in fair value and cash settlements of ineffective derivative contracts were recognized as derivative expense (income). All contracts previously designated as hedging instruments expired during 2012.

The tables below present the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase (decrease) to crude oil revenues for the effective portion and as an increase (decrease) to other (income) expense for the ineffective portion and amounts excluded from effectiveness testing:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Amount of gain reclassified from OCI into income (effective portion)	$—	$260	$—	$772
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	—	(282)	—	40

Note 6 - Fair Value Measurements

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

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

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Fair value of financial instruments

Cash, cash equivalents, short-term 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 on its Consolidated Balance Sheet. The fair value of Callon’s fixed-rate debt, which is valued using Level 2 inputs, is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

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

	September 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$17,000	$17,000	$10,000	$10,000
13% Senior Notes due 2016 (1)	108,220	100,718	110,668	100,112
Total	$125,220	$117,718	$120,668	$110,112

(1) Fair value is calculated only in relation to the $96,961 principal outstanding of the Senior Notes at each of the dates indicated above, respectively. The remaining $11,259 and $13,707, respectively, which the Company has recorded as a deferred credit, is excluded from the fair value calculation, and will be recognized in earnings as a reduction of interest expense over the remaining amortization period. See Note 4 for additional information.

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis (unless otherwise noted below) in the Company’s Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity derivative instruments: Callon’s derivative policy allows for commodity derivative instruments to consist of natural gas and crude oil collars, basis swaps, puts, calls and similar commodity instrument structures. The fair value of these derivatives is derived using a valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract, and the values are corroborated by quotes obtained from counterparties to the agreements. The Company’s fair value calculations, based on analysis of each contract, also incorporate an estimate of the counterparties’ default risk for derivative assets and an estimate of the Company’s default risk for derivative liabilities. The Company believes that the majority of the inputs used to calculate the commodity derivative instruments fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. See Note 5 for additional information regarding the Company’s derivative instruments.

Footnotes to the Financial Statements
Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

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

As of 9/30/2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$—	$—	$—
Derivative financial instruments - non-current	Other long-term assets	—	36	—	36
Sub-total assets		—	36	—	36
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$1,139	$—	$1,139
Derivative financial instruments - non-current	Other long-term liabilities	—	18	—	18
Sub-total liabilities	Other long-term liabilities	—	1,157	—	1,157
Total		$—	$(1,121)	$—	$(1,121)

As of 12/31/2012	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$1,674	$—	$1,674
Derivative financial instruments - non-current	Other long-term assets	—	250	—	250
Sub-total assets		—	1,924	—	1,924
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$125	$—	$125
Derivative financial instruments - non-current	Other long-term liabilities	—	116	—	116
Sub-total liabilities		—	241	—	241
Total		$—	$1,683	$—	$1,683

Assets and liabilities measured at fair value on a nonrecurring basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Asset retirement obligations ("ARO") incurred in current period. Callon estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as (1) the existence of a legal obligation for an ARO, (2) amounts and timing of settlements, (3) the credit-adjusted risk-free rate to be used and (4) inflation rates. AROs incurred during the nine months ended September 30, 2013, including no upward revisions, were Level 3 fair value measurements. See Note 8, Asset Retirement Obligations, which provides a summary of changes in the ARO liability.

Acquisition. In accordance with the acquisition method of accounting, the purchase price of the Company's acquisition during the period has been allocated to the assets acquired and liabilities assumed based on their estimated fair values on the acquisition date. In valuing the acquired assets and liabilities assumed, fair values were based on expected future cash flows based on estimated reserve quantities; costs to produce and develop reserves; and oil and gas forward prices. The fair value measurements were based on significant inputs not observable in the market and thus represent a level 3 measurement.

Note 7 - Income Taxes

The Company provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to statutory depletion and non-deductible executive compensation expenses. The effective tax rate for the nine months ended September 30, 2013 and 2012 was 48% and 33%, respectively. The 48% effective tax rate for the nine months ended September 30, 2013 is primarily a result of the permanent differences previously noted, as well as certain discrete items occurring in the second quarter of 2013, including shortfalls associated with the Company's restricted stock awards vesting during the period. We have no liability for uncertain tax positions or any accrued interest or penalties as of September 30, 2013.

Unless otherwise indicated, amounts included in the footnotes to the financial statements are presented in thousands, except for share, well, acreage and per-derivative instrument data.

Note 8 - Asset Retirement Obligations

The table below summarizes the Company's asset retirement obligations activity for the nine months ended September 30, 2013:

Asset retirement obligations at January 1, 2013	$13,301
Accretion expense	1,556
Liabilities incurred	624
Liabilities settled	(497)
Revisions to estimate	(3,477)
Asset retirement obligations at end of period	11,507
Less: Current asset retirement obligations	6,002
Long-term asset retirement obligations at September 30, 2013	$5,505

Certain of the Company's operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the Consolidated Balance Sheets as restricted investments were $3,800 at September 30, 2013. These investments include primarily U.S. Government securities, and are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's crude oil and natural gas properties.

On October 17, 2013, the Company announced entrance into an agreement to sell its interest in the Medusa field, Medusa Spar LLC, and substantially all of its Gulf of Mexico shelf properties to W&T. Under the agreement, which is expected to close on or before November 30, 2013, W&T will assume an estimated $4,500 of the ARO related to these offshore assets. See Note 2 for additional information.

Note 9 - Equity Transaction

On May 30, 2013, the Company issued $75,000 of 10.0% Series A Cumulative Preferred Stock (the "Preferred Stock") and received $70,000 net proceeds after deducting the underwriting commissions and offering expenses. The sale consisted of 1.6 million shares of Preferred Stock, par value $0.01 per share, public offering price of $47.50 per share and liquidation preference of $50.00 per share in an underwritten public offering. The Preferred Stock ranks senior to the Company's common stock with respect to the payment of dividends and distribution of assets upon liquidation or dissolution. The Preferred Stock has no stated maturity and is not subject to mandatory redemption or any sinking fund. The Preferred Stock will remain outstanding indefinitely unless repurchased by the Company or converted into Callon common stock in connection with certain changes in control as defined in the Preferred Stock prospectus.

Holders of the Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors (the "Board"), 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. The first dividend date for the Preferred Stock was June 30, 2013, and these dividends were paid on June 28, 2013 (as June 30 fell on a weekend) in the amount of $0.43 per share or $680 for the stub period beginning with the issuance on May 30, 2013 through the dividend date on June 30, 2013. On September 3, 2013, the Board of Directors declared a dividend of $1.25 per share, or a total of $1,974, on the Company's Preferred Stock to stockholders of record at the close of business on September 13, 2013, and the dividends were paid on September 30, 2013. To date in 2013, the Company has recognized dividend expense of $2,654.

Beginning on May 30, 2018, the Company may, solely at its option, redeem the Preferred Stock in whole at any time, or in part from time to time, for cash at a redemption price of $50.00 per share, plus accrued and unpaid dividends (whether or not declared) to the redemption date. The Company may redeem the Preferred Stock following certain changes of control as defined in the Preferred Stock prospectus, in whole or in part, within 120 days after the date on which the change of control has occurred, for cash at $50.00 per share, plus accrued and unpaid dividends (whether or not declared) to the redemption date. If the Company elects not to exercise this option, the holders of the Preferred Stock have the option to convert each share of Preferred Stock into a predefined number of Company common shares, subject to certain adjustments. As defined in a provision of the Preferred Stock prospectus, the common shares reserved for issuance vary based on the number of authorized common shares. Based on the Company's 60 million currently authorized shares, 16.8 million shares are reserved for a potential conversion.

The number of reserved common shares increases to a maximum of 42.2 million at such time as the Company's authorized common shares increase. Except as required by law, holders of the Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such dividends in arrears are paid in full, the holders will be entitled to elect two directors to the Board, which will increase in size by that same number of directors.

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Special Note Regarding Forward Looking Statements

All statements, other than historical fact or present financial information, 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. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

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 commodities (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 respond to low natural gas prices,
- our ability to fund our planned capital investments,
- the impact of government regulation, including 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, including the pending sale of our Medusa property,
- 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 Securities and Exchange Commission (“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 crude 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, 2012 (the “2012 Annual Report on Form 10-K”), and all quarterly reports on Form 10-Q filed subsequently thereto ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or elsewhere in our 2012 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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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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 2012 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 have been engaged in the exploration, development, acquisition and production of crude oil and natural gas properties since 1950. In 2009, we began to shift our operational focus from exploration in the Gulf of Mexico to building an onshore asset portfolio to provide a multi-year, low-risk drilling program in both crude oil and natural gas basins. A significant portion of this onshore transition has been funded by reinvesting the cash flows from our Gulf of Mexico properties. In the fourth quarter of 2012, we monetized our interest in the deepwater Habanero field in order to accelerate development of our onshore properties. In October 2013, we entered into an agreement to sell our interest in our remaining deepwater property, the Medusa field, the Company's interest in the Medusa Spar facility and substantially all remaining offshore shelf properties. This transaction will complete our long-term goal of becoming an onshore operator upon closing with an asset base concentrated in the Permian Basin.

Recent key accomplishments and development progress:

- In October, we signed a purchase and sale agreement with W&T Offshore, Inc., to sell our interest in the Medusa field, Medusa Spar LLC, and substantially all our remaining shelf properties for a net cash consideration of $100 million, accelerating our cash flows from these offshore properties, monetizing the value of additional undeveloped reserve potential, and completing our transition to onshore.

- In August, we increased our capital budget by 36% to $170 million with approximately 87% of our budgeted operating expenditures (including drilling, completion, and infrastructure) allocated to our Midland Basin operations in an effort to accelerate the development of our fields in the southern and central portions of the Basin.

- In August, we accepted delivery of an additional horizontal drilling rig under a one-year contract to support our expanded drilling program.

- We continue the execution of our horizontal drilling program focused on the Wolfcamp B shale (gross production data provided):

East Bloxom: We currently have five Upper Wolfcamp B wells on production in the field, with a demonstrated average initial peak 24-hour rate ("24-hour rate") of 1,108 Boe per day. Our most recent well placed on production, the Neal 322H is currently producing and two additional Upper Wolfcamp B wells continue to flow back. Based on our current drilling schedule, we expect to have a total of eight Wolfcamp B wells on production by year-end 2013.

Taylor Draw: We currently have four Upper Wolfcamp B wells on production in the field, with a demonstrated average 24-hour rate of 625 Boe per day. We also have one Lower Wolfcamp B well on production that produced at a 24-hour rate of 755 Boe per day. The average lateral length for these five wells is 4,700 feet. Three additional Lower Wolfcamp B wells, with an average lateral length of 8,250, are in the process of being fracture stimulated.

In addition, we have commenced horizontal development of the Wolfcamp B at both our Carpe Diem and Garrison Draw fields.

- We also continue to delineate our acreage to expand our inventory of drilling opportunities:

  We recently completed a vertical well targeting the Mississippian formation in Borden County as part of our Northern Midland evaluation program. The well produced at a rate of 326 Boe per day. We intend to drill an additional three vertical wells in the coming months before a decision is made to drill a horizontal well in 2014.

As part of our ongoing efforts to evaluate additional horizontal development zones, we recently tested the Wolfcamp A shale in the East Bloxom field. The well encountered mechanical problems and produced at a 24-

hour rate of 302 Boe per day. We currently plan to drill our next Wolfcamp A well in the field in the first quarter of 2014.

In our Pecan Acres field, our first vertical well to simultaneously complete multiple zones down to the Woodford shale produced at a gross peak initial (24-hour) production rate of 520 Boe per day. We will continue pursuing this program of completing vertical wells to deep zones in the field and seek to evaluate the concept on other acreage in the future.

Overview and Outlook

Production and highlights of our operations include:

	Net Production (MBoe) Three Months Ended September 30,			
	2013	2012	Change	% Change
Onshore - Permian Basin:				
Southern portion	181	116	65	56 %
Central portion	45	49	(4)	(8)%
Total Permian	226	165	61	37 %
Offshore - Deepwater Properties				
Medusa	94	117	(23)	(20)%
Habanero	—	21	(21)	(100)%
Total Deepwater	94	138	(44)	(32)%
Other:				
Haynesville Shale	3	12	(9)	(75)%
Gulf of Mexico shelf	79	84	(5)	(6)%
Total Other	82	96	(14)	(15)%
Total	402	399	3	1 %

	Net Production (MBoe) Nine Months Ended September 30,			
	2013	2012	Change	% Change
Onshore - Permian Basin:				
Southern portion	397	278	119	43 %
Central portion	142	143	(1)	(1)%
Total Permian	539	421	118	28 %
Offshore - Deepwater Properties				
Medusa	271	343	(72)	(21)%
Habanero	1	102	(101)	(99)%
Total Deepwater	272	445	(173)	(39)%
Other:				
Haynesville Shale	17	35	(18)	(51)%
Gulf of Mexico shelf	232	264	(32)	(12)%
Total Other	249	299	(50)	(17)%

Total	1,060	1,165	(105)	(9)%

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

The following table sets forth productive wells as of September 30, 2013:

	Crude Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	125	101.1	11	4.8
Royalty interest	3	0.10	2	0.08
Total	128	101.2	13	4.88

Highlights of our onshore development program and offshore assets include:

Onshore – Permian Basin

We expect that our production and reserve growth initiatives will continue to focus primarily on the Permian Basin, in which we own approximately 40,275 gross (34,931 net) acres as of September 30, 2013. In order to advance our growth plans, we are directing a significant amount of our 2013 capital budget to horizontal drilling of the Wolfcamp shale formation in the Permian Basin, while continuing to support our ongoing vertical Wolfberry program. The following table summarizes the Company's drilling progress in the Permian Basin for the nine months ended September 30, 2013:

	Drilled		Completed (a)	
	Gross	Net	Gross	Net
Southern portion:				
Vertical wells	1	1	—	—
Horizontal wells	13	11.75	9	8.23
Total southern portion	14	12.75	9	8.23
Central portion:				
Vertical wells	4	2.58	6	3.97
Horizontal wells	—	—	—	—
Total central portion	4	2.58	6	3.97
Northern portion:				
Vertical wells	1	1	1	0.75
Horizontal wells	—	—	1	0.75
Total northern portion	1	1	2	1.50
Total vertical wells	6	4.58	7	4.72
Total horizontal wells	13	11.75	10	8.98
Total	19	16.33	17	13.70

(a) Completions include wells drilled prior to 2013.

Southern portion: We currently own approximately 9,971 net acres in the southern portion of the Permian Basin. Our current production in the southern portion of the Midland Basin (Crockett, Reagan and Upton Counties in Texas) is derived from vertical drilling operations in the Wolfberry play and horizontal development of the Wolfcamp shale.

During the second quarter of 2013, we acquired 2,468 gross (2,186 net) acres and seven gross vertical wells in southern Reagan and Upton Counties, Texas, which constitutes our Garrison Draw field. During the third quarter, we drilled one gross vertical and one gross horizontal well in this field with plans to drill one additional gross horizontal well by year-end.

We recently increased our level of horizontal drilling activity in 2013 in this portion of the Basin with plans to drill a total of 18 horizontal wells in 2013. Given this level of sustained activity and our desire to maximize capital efficiency, we have implemented pad-drilling and have recently established the infrastructure to complete multiple wells simultaneously.

Central portion: We currently own approximately 3,343 net acres in the central portion of the Permian Basin. Our current production in the central portion of the Midland Basin (Ector, Glasscock, and Midland Counties in Texas) is primarily from the Wolfberry play, which has recently been modified in this area to include deeper target zones below the Atoka formation.

In late 2012, we modified our Wolfberry drilling program in the Pecan Acres field to target deeper intervals below the Atoka formation. Given initial results from this initiative, our future vertical drilling plans in both Pecan Acres and Carpe Diem fields will incorporate these deeper zones as part of the completion design.

We recently commenced drilling of our first two horizontal wells at our Carpe Diem field. These wells are targeting the Upper Wolfcamp B and are anticipated to be completed before year-end 2013.

Northern portion: We currently own approximately 21,617 net acres in the northern portion of the Permian Basin, which includes the 14,653 net acres in Borden County, Texas and 6,964 net acres in Lynn County, Texas. Although the area has experienced a recent increase in drilling activity, the northern Midland Basin has had limited drilling activity compared with the southern Basin (the location of our current production), which significantly increases the risk associated with successful drilling activities in this area.

Callon continues to progress its delineation efforts on its Borden County acreage. To date, two horizontal and two vertical wells have been drilled to evaluate multiple prospective zones. The most recent vertical well, the Lacey Newton 2801, produced at a peak 24-rate of 326 boepd (92% oil).

Offshore - Deepwater properties

As discussed in Note 2, on October 17, 2013, the Company entered into a purchase and sale agreement with W&T for a net cash consideration of approximately $100 million before customary purchase price adjustments. On November 5, 2013, the parties closed on a portion of the transaction for which the Company received $76.4 million in proceeds. The remainder of the transaction is expected to close with adjusted proceeds of approximately $11.5 million on or before November 30, 2013.

Our net interest in the Medusa field, our remaining deepwater property, produced an average of 993 Boe per day during the nine months ended September 30, 2013, approximately 88% being crude oil that receives pricing based on Mars benchmark crude.

Other – Haynesville shale

We own a 69% working interest in a 429 net acre unit in the Haynesville shale play in Bossier Parish, Louisiana. As of September 30, 2013, our Haynesville well was producing approximately 374 Mcf of natural gas per day. We currently have no drilling obligations related to this lease position. In October of 2013, we entered into an agreement to sell this property for $2 million.

Other – Gulf of Mexico shelf properties

As discussed in Note 2, these properties comprise part of the asset sale to W&T. During the nine months ended September 30, 2013, our shelf properties produced 233 MBoe, which accounted for 22% of our total production, of which 96% was natural gas. Production from the East Cameron Block 257 field, which had been shut-in since November 2011, recommenced on May 9, 2013, and contributed an average of 271 Boe per day of production for the third quarter. Following the completion of our recent asset sale, we will retain our interest in two non-producing fields, both of which are in various stages of plugging and abandonment.

Liquidity and Capital Resources

Historically, our primary sources of funding have been cash flows from operations, borrowings from financial institutions, the sale of debt and equity securities and divestitures, such as the sale of our interest in the deepwater Habanero field.

Cash and cash equivalents of $0.9 million decreased by $0.2 million at September 30, 2013 compared to $1.1 million at December 31, 2012. As of September 30, 2013, the Company's liquidity position approximated $58.9 million inclusive of cash and cash equivalents and available borrowing capacity under our Credit Facility. Liquidity has subsequently been enhanced by the previously discussed increase in the Company's borrowing base under the Credit Facility and will further be increased by the receipt of the $100 million proceeds (before closing adjustments) from the previously discussed asset sale (see Note 2).

On May 30, 2013, we issued $75.0 million of 10.0% Series A Cumulative Preferred Stock (the "Preferred Stock") and received $70 million net proceeds after deducting underwriting commissions and offering expenses. The Preferred Stock requires dividend payments of approximately $1.9 million per quarter.

As of September 30, 2013, our $200 million Credit Facility had an associated borrowing base of $75 million with a maturity date of March 15, 2016. Amounts borrowed under the Credit Facility may not exceed a borrowing base, which is generally reviewed on a semi-annual basis and is then eligible for re-determination. The Credit Facility is secured by mortgages covering the Company's major producing fields. In November 2013, the Credit Facility's borrowing base was increased to $83 million following a review of the Company's reserve base, pro forma for the sale of the Gulf of Mexico properties and the assumed repayment of 50% of the outstanding principal of the Senior Notes. However, to the extent the Company elects not to redeem the Senior Notes before December 20, 2013, the borrowing base would be reduced by $0.25 million for each $1 million of the Senior Notes outstanding in excess of $48 million.

As of September 30, 2013, the balance outstanding on the Credit Facility was $17 million with an interest rate of 2.7%, calculated as the London Interbank Offered Rate ("LIBOR") plus a tiered rate ranging from 2.5% to 3.0%, which is based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.5% per annum on the unused portion of the borrowing base, which is payable quarterly. The Company plans to use a portion of the proceeds from the previously discussed asset sale, subsequent to closing, to pay down the outstanding balance on the Credit Facility.

At September 30, 2013, we had approximately $97 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly. Following the completion of the previously discussed asset divestiture (See Note 2) and as it relates to the borrowing base discussion above, we may allocate a portion of the proceeds from the sale to redeem all or a portion of the Senior Notes outstanding and thereby reduce future interest expense. We also continue to monitor for acquisition opportunities we believe would be accretive to shareholder value.

2013 capital expenditures

Our revised 2013 capital budget (excluding acquisitions) approximates $170 million and represents a 36% increase over the previous 2013 capital development budget estimate of $125 million. The increase relates to expenditures for additional development activities on our Midland Basin acreage. Approximately 87% of our budgeted operational expenditures (including drilling, completion and infrastructure) are allocated to our Midland Basin operations. Our budget includes further exploration and development of our Permian Basin properties with plans to complete approximately 27 gross wells including 20 horizontal wells and seven vertical wells. Components of the 2013 capital budget include (in millions):

Midland Basin	$148
Gulf of Mexico	4
Total budgeted capital expenditures	$152
Capitalized general and administrative costs	14
Capitalized interest and other	4
Total budgeted capitalized expenses	$18
Total operational budget	170
Acquisition - Southern Midland Basin	11
Total capital expenditures, including acquisition	$181

We believe that our cash on hand and the availability under our Credit Facility, combined with our expected operating cash flow based on current commodity prices and forecasted production, will be adequate to meet our forecasted capital expenditures, interest payments, and operating requirements for the remainder of 2013. Depending on economic conditions or the Company's operational results, our capital budget may be adjusted up or down as deemed appropriate.

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

The capital expenditures for the nine months ended September 30, 2013 include the following (in millions):

Southern Midland Basin	$71
Central Midland Basin	12
Northern Midland Basin	5
Total capital expenditures	$88
Capitalized general and administrative costs	10
Capitalized interest and other	3
Total capitalized expenses	$13
Total operational expenditures	101
Acquisition - Southern Midland Basin	11
Total capital expenditures, including acquisition	$112

Summary cash flow information is provided as follows:

Operating activities. For the nine months ended September 30, 2013, net cash provided by operating activities decreased $6.2 million to $35.2 million, from $41.4 million for the same period in 2012 and relates primarily to a $6.0 million reduction in revenue stemming from a 9% decrease in equivalent production. These decreases were partially offset by a 2% increase in price per equivalent unit produced and lower operating expenses. Realized prices and production volumes are discussed below within Results of Operations.

Investing activities. For the nine months ended September 30, 2013, net cash used in investing activities was $109.9 million as compared to $113.5 million for the same period in 2012. The $3.6 million decrease is primarily attributable to a reduction in property acquisition expenditures in the nine-month period of the current year as compared to the corresponding period of 2012.

Financing activities. For the nine months ended September 30, 2013, net cash provided by financing activities was $74.4 million compared to cash provided by financing activities of $29.8 million during the same period of 2012. The $44.6 million increase relates primarily to the $70.0 million net proceeds from the previously discussed preferred stock offering, which was offset primarily by cash used to repay amounts outstanding on our Credit Facility.

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

Results of Operations

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

	Three Months Ended September 30,			
	2013	2012	Change	% Change
Net production:				
Crude oil (MBbls)	257	251	6	2 %
Natural gas (MMcf)	864	890	(26)	(3)%
Total production (MBoe)	402	399	3	1 %
Average daily production (MBoe)	4.4	4.3	0.1	2 %
Average realized sales price (a):				
Crude oil (Bbl)	$105.11	$95.86	$9.25	10 %
Natural gas (Mcf)	$4.38	$3.76	$0.62	16 %
Average realized sales price on an equivalent basis (Boe)	$76.61	$68.67	$7.94	12 %
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$27,014	$24,061	$2,953	12 %
Natural gas revenue	3,783	3,341	442	13 %
Total	$30,797	$27,402	$3,395	12 %
Additional per Boe data:				
Average realized sales price	$76.61	$68.67	$7.94	12 %
Lease operating expense	13.11	13.05	0.06	< 1%
Production taxes	2.47	1.64	0.83	51 %
Operating margin	$61.03	$53.98	$7.05	13 %
Other expenses per Boe:				
Depletion, depreciation and amortization	$29.62	$29.99	$(0.37)	(1)%
General and administrative	14.49	16.14	(1.65)	(10)%

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price:

Average NYMEX price per barrel ("Bbl") of crude oil	$105.82	$92.22	$13.60	15 %
Basis differential and quality adjustments	(0.24)	3.28	(3.52)	(107)%
Transportation	(0.47)	(0.68)	0.21	(31)%
Hedging	—	1.04	(1.04)	(100)%
Average realized price per Bbl of crude oil	$105.11	$95.86	9.25	10 %
Average NYMEX price per million British thermal units ("MMBtu")	$3.56	$2.90	$0.66	23 %
Basis differential, quality and Btu adjustments	0.82	0.86	(0.04)	(5)%
Average realized price per Mcf of natural gas	$4.38	$3.76	$0.62	16 %

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

	Nine Months Ended September 30,			
	2013	2012	Change	% Change
Net production:				
Crude oil (MBbls)	661	716	(55)	(8)%
Natural gas (MMcf)	2,389	2,695	(306)	(11)%
Total production (MBoe)	1,060	1,165	(105)	(9)%
Average daily production (MBoe)	3.9	4.3	(0.4)	(9)%
Average realized sales price (a):				
Crude oil (Bbl)	$99.27	$100.39	$(1.12)	(1)%
Natural gas (Mcf)	$4.39	$3.77	$0.62	16%
Average realized sales price on an equivalent basis (Boe)	$71.79	$70.44	$1.35	2%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$65,615	$71,883	$(6,268)	(9)%
Natural gas revenue	10,483	10,174	309	3%
Total	$76,098	$82,057	$(5,959)	(7)%
Additional per Boe data:				
Average realized sales price	$71.79	$70.44	$1.35	2%
Lease operating expense	15.48	16.04	(0.56)	(3)%
Production taxes	2.09	1.53	0.56	37%
Operating margin	$54.22	$52.87	$1.35	3%
Other expenses per Boe:				
Depletion, depreciation and amortization	$31.70	$30.90	$0.80	3%
General and administrative	13.31	13.60	(0.29)	(2)%

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price:

	2013	2012	Change	% Change
Average NYMEX price per barrel ("Bbl") of crude oil	$98.14	$96.21	$1.93	2%
Basis differential and quality adjustments	1.66	3.84	(2.18)	(57)%
Transportation	(0.53)	(0.74)	0.21	(28)%
Hedging	—	1.08	(1.08)	(100)%
Average realized price per Bbl of crude oil	$99.27	$100.39	$(1.12)	(1)%
Average NYMEX price per million British thermal units ("MMBtu")	$3.68	$2.43	$1.25	51%
Basis differential, quality and Btu adjustments	0.71	1.34	(0.63)	(47)%
Average realized price per Mcf of natural gas	$4.39	$3.77	$0.62	16%

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

Revenues

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

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the three-months ended September 30, 2011	$26,537	$7,013	$33,550
Volume increase (decrease)	$(1,888)	$(2,154)	$(4,042)
Price increase (decrease)	(848)	(1,518)	(2,366)
Impact of hedges	260	—	260
Net increase (decrease) in 2012	(2,476)	(3,672)	(6,148)
Revenues for the three-months ended September 30, 2012	$24,061	$3,341	$27,402
Volume increase (decrease)	$671	$(94)	$577
Price increase (decrease)	2,282	536	2,818
Net increase (decrease) in 2013	2,953	442	3,395
Revenues for the three-months ended September 30, 2013	$27,014	$3,783	$30,797

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the nine-months ended September 30, 2011	$74,428	$21,404	$95,832
Volume increase (decrease)	$(2,978)	$(7,030)	$(10,008)
Price increase (decrease)	(339)	(4,200)	(4,539)
Impact of hedges	772	—	772
Net increase (decrease) in 2012	(2,545)	(11,230)	(13,775)
Revenues for the nine-months ended September 30, 2012	$71,883	$10,174	$82,057
Volume increase (decrease)	$(5,522)	$(1,155)	$(6,677)
Price increase (decrease)	(746)	1,464	718
Net increase (decrease) in 2013	(6,268)	309	(5,959)
Revenues for the nine-months ended September 30, 2013	$65,615	$10,483	$76,098

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

Crude oil revenue

Crude oil revenues increased 12% to $27.0 million for the three months ended September 30, 2013 compared to revenues of $24.1 million for the same period of 2012. Contributing to the increase in crude oil revenue was a 10% increase in realized crude oil prices compounded by a 2% increase in production. The average realized sales price increased to $105.11 per barrel during the third quarter of 2013 compared to $95.86 during the same period in 2012. The increase in production was primarily attributable to a 43 thousand barrels (“MBbls”) increase in production from our Permian properties, partially offset by a 19 MBbls decline in production from our Medusa field due to normal and expected declines, and the sale of our deepwater Habanero field in the fourth quarter of 2012, which produced 17 MBbls in the third quarter of 2012.

Crude oil revenues decreased 9% to $65.6 million for the nine months ended September 30, 2013, compared to revenues of $71.9 million for the same period of 2012. While the average oil price realized decreased by a modest 1%, total production decreased 8%. The decrease in production was largely offset by the 87 MBbls increase in our crude oil production from our Permian properties. The decrease was primarily attributable to the sale of Habanero in the fourth quarter of 2012, normal and expected decline at our Medusa field in the third quarter of 2013, mentioned above, and 20 days of down time for scheduled downstream pipeline maintenance at our Medusa field in the second quarter of 2013.

Natural gas revenue

Natural gas revenues of $3.8 million increased 13% during the three months ended September 30, 2013 as compared to natural gas revenues of $3.3 million for the same period of 2012. The increase primarily relates to a 16% increase in the average price realized partially offset by a 3% decrease in natural gas volumes. The decrease in production was driven largely by the sale of Habanero, the plugging and abandonment of our Mobile Bay 908 property, and normal and expected declines from our existing wells. These declines were primarily offset by the 106 million cubic feet (“MMcf’) increase in natural gas production from our Permian properties and an increase from our East Cameron 257 field, which had been shut-in since November 2011 and returned to production in May of 2013.

Natural gas revenues of $10.5 million remained relatively flat during the nine months ended September 30, 2013, as compared to natural gas revenues of $10.2 million for the same period of 2012. The average price realized increased 16% and total production decreased 11%. The decrease in production was primarily attributable to the plugging and abandonment of our Mobile Bay 908 property and the sale of Habanero, mentioned above, as well as normal and expected declines from our existing wells. These declines were largely offset by the 186 MMcf increase in production from our Permian properties and an increase from our East Cameron 257 field, discussed above.

Our natural gas prices on an MMBtu equivalent basis exceeded the related NYMEX prices primarily due to the value of the NGLs in our natural gas stream from our Permian Basin and offshore production.

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

Operating Expenses

(in thousands except per unit data)	Three Months Ended September 30,							
		Per		Per	Total Change		Boe Change	
	2013	Boe	2012	Boe	$	%	$	%
Lease operating expenses	$5,270	$13.11	$5,203	$13.05	$67	1 %	$0.06	— %
Production taxes	991	2.47	656	1.64	335	51 %	0.83	51 %
Depreciation, depletion and amortization	11,907	29.62	11,965	29.98	(58)	— %	(0.36)	(1)%
General and administrative	5,826	14.49	6,441	16.14	(615)	(10)%	nm	nm
Accretion expense	458	1.14	574	1.44	(116)	(20)%	nm	nm

(in thousands except per unit data)	Nine Months Ended September 30,							
		Per		Per	Total Change		Boe Change	
	2013	Boe	2012	Boe	$	%	$	%
Lease operating expenses	$16,412	$15.48	$18,687	$16.04	$(2,275)	(12)%	$(0.56)	(3)%
Production taxes	2,217	2.09	1,778	1.53	439	25 %	0.56	37 %
Depreciation, depletion and amortization	33,603	31.70	35,998	30.90	(2,395)	(7)%	0.80	3 %
General and administrative	14,110	13.31	15,846	13.60	(1,736)	(11)%	nm	nm
Accretion expense	1,556	1.47	1,709	1.47	(153)	(9)%	nm	nm

*nm = not meaningful

Lease operating expenses ("LOE")

LOE remained relatively flat for the three months ended September 30, 2013. The slight increase is related to the significant growth in the number of wells now producing on our Permian Basin properties, partially offset by the sale of our interest in the Habanero deepwater property in December 2012.

LOE, while relatively flat on a per unit basis, in total it decreased by $2.3 million for the nine months ended September 30, 2013, as compared to the same period in 2012. The decrease was primarily due to $2.9 million in LOE incurred at our Haynesville well in the first quarter of 2012 for which we had no similar costs in the current period. As discussed above, the additional LOE from our Permian properties is offset by the decrease from the sale of our interest in the Habanero property.

Production taxes

Production taxes increased for both the three and nine months ended September 30, 2013 as compared to the same periods of 2012, due to an increase of onshore production subject to these taxes while our offshore production is exempt from production taxes.

Depreciation, depletion and amortization ("DD&A")

DD&A remained relatively flat for the three months ended September 30, 2013 compared to the same period of 2012, while DD&A for the nine months ended September 30, 2013 decreased 7% compared to the same period of 2012. The decrease is primarily related to the 9% decline in total production offset by a 3% rate increase during the the first nine months of 2013 compared to the same period of 2012.

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

G&A decreased $0.6 million during the three months ended September 30, 2013 compared to the same period of 2012 and relates primarily to costs in 2012 for non-recurring additional employee-related items including early retirement and severance expense for which we had no similar costs in the current period.

Similarly, for the nine months ended September 30, 2013 and as compared to the same period of 2012, G&A decreased $1.7 million, primarily attributable to a of $0.9 million reduction in costs related to mark-to-market liability-based incentive compensation instruments and $0.8 million of non-recurring additional employee-related costs mentioned above.

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

Accretion expense

See Note 8 for additional information regarding the Company's ARO.

Other Income and Expenses

(in thousands)	Three Months Ended September 30,			
	2013	2012	$ Change	% Change
Interest expense	$1,417	$2,135	$(718)	(34)%
Loss on derivative contracts	3,686	1,598	2,088	(131)%
Other (income) expense, net	(279)	237	(516)	(218)%
Income tax expense (benefit)	456	(246)	702	(285)%
Equity in earnings of Medusa Spar LLC	17	56	(39)	(70)%
Preferred stock dividends	(1,974)	—	(1,974)	100%

(in thousands)	Nine Months Ended September 30,			
	2013	2012	$ Change	% Change
Interest expense	$4,469	$7,096	$(2,627)	(37)%
Gain on early extinguishment of debt	—	(1,366)	1,366	(100)%
Loss (Gain) on derivative contracts	2,123	(1,977)	4,100	(207)%
Other income, net	(368)	(224)	(144)	64%
Income tax expense	950	1,508	(558)	(37)%
Equity in earnings of Medusa Spar LLC	14	180	(166)	(92)%
Preferred stock dividends	(2,654)	—	(2,654)	100%

Interest expense

Interest expense incurred during the three and nine months ended September 30, 2013 decreased $0.7 million and $2.6 million, respectively, compared to the same periods of 2012 and is primarily related to $0.5 million and $2.2 million increases in capitalized interest for the comparative three and nine month periods, respectively. The additional capitalized interest relates to a higher average unevaluated property balance period over period.

Gain on early extinguishment of debt

During June 2012, we redeemed $10 million of our Senior Notes with a carrying value of $11.6 million, including $1.6 million of the notes' deferred credit, in exchange for $10.2 million, comprised of the $10 million principal of the Notes and $0.2 million of redemption expenses, which resulted in a $1.4 million net gain on the early extinguishment of debt.

Loss (Gain) on derivative contracts

See Note 5 for a reconciliation of the realized and unrealized components of the Company's derivative contracts.

Income tax expense

Please see Note 7 for a discussion of our effective tax rates for the periods presented above.

Preferred stock dividends

Preferred Stock dividends for the three and nine months ended September 30, 2013 increased $2.0 million and $2.7 million, respectively, compared to the same periods of 2012 in which we had no dividend expense. Dividend expense of $2.0 million for the three-month period is consistent with its 10% dividend rate and $75 million face value, while the dividend expense of $2.7 million for the nine-month period is reflective of the Preferred Stock being outstanding only since its issuance on May 30, 2013 resulting in a reduced stub period payment during the second quarter of 2013.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity price risk

The Company's revenues are derived from the sale of its crude oil and natural gas production. The prices for crude 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 crude oil and natural gas price risk. The total volumes which we hedge through the use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 50% to 75% of our anticipated internally forecasted production for the next 12 to 24 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

As of November 1, 2013, we have commodity contracts covering approximately 75% and 46% of our internally forecasted proved developed producing crude oil and natural gas production, respectively, from October 2013 through December 2013. Our actual production will vary from the amounts estimated, perhaps materially. See Note 5 to the Consolidated Financial Statements for a description of the Company's outstanding derivative contracts at September 30, 2013.

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.

The Company may utilize price "collars" to reduce the risk of changes in crude 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 and below the ceiling price 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 counter-party receives the difference from the Company.

Callon may purchase "puts" which reduce the Company's exposure to decreases in crude oil and natural gas prices while allowing realization of the full benefit from any increases in crude oil and natural gas prices. If the price falls below the floor, the counter-party pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile crude 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, 2013, the majority of the Company's debt consisted of its fixed-rate 13% Senior Notes. The Company's Credit Facility, however, includes a variable interest rate, which can fluctuate with changes in specific short-term interest rates such as LIBOR. Although the Company had $17 million borrowings outstanding at September 30, 2013 under its Credit Facility, were the Company to fully draw its available $75 million borrowing base at the beginning of a fiscal quarter, a 100 basis point change in the variable interest rate would increase the Company's quarterly interest expense by $0.02 million. For additional information, see Note 4 to the Consolidated Financial Statements regarding the Company's Credit Facility and other borrowings at September 30, 2013.

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, is accumulated and communicated to the issuer’s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Company’s principal executive and principal financial officers have concluded that the Company’s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”)) were effective as of September 30, 2013.

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

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Part II. Other Information

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes with respect to the risk factors disclosed in our 2012 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	Certificate of Incorporation of the Company, as amended (incorporated by reference from Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003 filed March 15, 2004, File No. 001-14039)
3.2	Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
3.3	Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
3.4	Certificate of Amendment to the Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.4 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 001-14039)
3.5	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)
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	Indenture for the Company's 13.00% Senior Notes due 2016, dated November 24, 2009, between Callon Petroleum Company, the subsidiary guarantors described therein, Regions Bank and American Stock Transfer & Trust Company (incorporated by reference to Exhibit T3C to the Company's Form T3, filed November 19, 2009, File No. 022-28916)
4.3	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	Purchase and Sale Agreement dated as of October 17, 2013 between Callon Petroleum Company and W&T Offshore, Inc. (incorporated by reference to Exhibit 10.1 of the Company's Report on Form 8-K filed October 21, 2013).
31.	Certifications
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.*	Interactive Data Files
*	Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability.

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SIGNATURES

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

	Callon Petroleum Company	
Signature	Title	Date
/s/ Fred L. Callon Fred L. Callon	President and Chief Executive Officer	November 7, 2013
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	November 7, 2013