CALLON PETROLEUM CO
Form 10-Q
August 08, 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: June 30, 2013
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)	(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 ¨

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 ¨

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 ¨ Accelerated filer x

Non-accelerated filer ¨ 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 x

As of August 5, 2013 there were outstanding 40,328,507 shares of the Registrant’s common stock, par value $0.01 per share.

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Part I. Financial Information

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

	June 30, 2013	December 31, 2012
ASSETS	Unaudited	
Current assets:		
Cash and cash equivalents	$13,406	$1,139
Accounts receivable	15,828	15,608
Fair market value of derivatives	1,647	1,674
Other current assets	904	1,502
Total current assets	31,785	19,923
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,583,159	1,497,010
Less accumulated depreciation, depletion and amortization	(1,317,961)	(1,296,265)
Net oil and natural gas properties	265,198	200,745
Unevaluated properties excluded from amortization	55,182	68,776
Total oil and natural gas properties	320,380	269,521
Other property and equipment, net	9,926	10,058
Restricted investments	3,800	3,798
Investment in Medusa Spar LLC	7,946	8,568
Deferred tax asset	63,892	64,383
Other assets, net	3,474	1,922
Total assets	$441,203	$378,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$40,637	$36,016
Asset retirement obligations	6,223	2,336
Fair market value of derivatives	106	125
Total current liabilities	46,966	38,477
13% Senior Notes:		
Principal outstanding	96,961	96,961
Deferred credit, net of accumulated amortization of $19,415 and $17,800, respectively	12,092	13,707
Total 13% Senior Notes	109,053	110,668
Senior secured revolving credit facility	—	10,000
Asset retirement obligations	7,175	10,965
Other long-term liabilities	1,474	2,092
Total liabilities	164,668	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 outstanding, respectively	16	—

Common stock, $0.01 par value, 60,000 shares authorized; 40,277 and 39,801 shares outstanding, respectively	404	398
Capital in excess of par value	399,380	328,116
Retained deficit	(123,265)	(122,543)
Total stockholders' equity	276,535	205,971
Total liabilities and stockholders' equity	$441,203	$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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Operating revenues:				
Crude oil sales	$19,061	$22,073	$38,601	$47,822
Natural gas sales	3,699	3,287	6,700	6,833
Total operating revenues	22,760	25,360	45,301	54,655
Operating expenses:				
Lease operating expenses	5,384	5,246	11,142	13,484
Production taxes	687	575	1,226	1,122
Depreciation, depletion and amortization	10,654	11,844	21,696	24,033
General and administrative	4,545	4,374	8,284	9,405
Accretion expense	533	562	1,098	1,135
Total operating expenses	21,803	22,601	43,446	49,179
Income from operations	957	2,759	1,855	5,476
Other (income) expenses:				
Interest expense	1,537	2,384	3,052	4,961
Gain on early extinguishment of debt	—	(1,366)	—	(1,366)
Gain on derivative contracts	(1,981)	(3,505)	(1,563)	(3,575)
Other income, net	(44)	(157)	(89)	(461)
Total other (income) expenses, net	(488)	(2,644)	1,400	(441)
Income before income taxes	1,445	5,403	455	5,917
Income tax expense	663	1,610	494	1,754
Income (loss) before equity in earnings of Medusa Spar LLC	782	3,793	(39)	4,163
Equity in (loss) earnings of Medusa Spar LLC	(24)	6	(3)	124
Net income (loss)	758	3,799	(42)	4,287
Preferred stock dividends	(680)	—	(680)	—
Net income (loss) available to common shareholders	$78	$3,799	$(722)	$4,287
Net income (loss) per common share:				
Basic	$0.00	$0.10	$(0.02)	$0.11
Diluted	$0.00	$0.09	$(0.02)	$0.11
Shares used in computing net income (loss) per common share:				
Basic	40,089	39,399	39,941	39,375
Diluted	40,323	40,155	39,941	40,204

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss)	$758	$3,799	$(42)	$4,287
Other comprehensive (loss) income:				
Change in fair value of derivatives designated as hedges, net of tax (See Note 5)	—	1,393	—	(77)
Comprehensive income (loss)	758	5,192	(42)	4,210
Preferred stock dividends	(680)	—	(680)	—
Comprehensive income (loss) available to common shareholders	$78	$5,192	$(722)	$4,210

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)

	Six Months Ended June 30, 2013	2012
Cash flows from operating activities:		
Net income (loss)	$(42)	$4,287
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	22,405	24,676
Accretion expense	1,098	1,135
Amortization of non-cash debt related items	228	225
Amortization of deferred credit	(1,615)	(1,538)
Non-cash gain on early extinguishment of debt	—	(1,366)
Equity in loss (earnings) of Medusa Spar LLC	3	(124)
Deferred income tax expense	494	1,754
Unrealized loss (gain) on derivative contracts	(249)	(3,897)
Non-cash expense related to equity share-based awards	734	722
Change in the fair value of liability share-based awards	(852)	989
Payments to settle asset retirement obligations	(615)	(1,029)
Changes in current assets and liabilities:		
Accounts receivable	789	(2,036)
Other current assets	598	63
Current liabilities	(324)	4,756
Payments to settle vested liability share-based awards	(239)	(199)
Change in natural gas balancing receivable	(118)	(95)
Change in natural gas balancing payable	(62)	(17)
Change in other long-term liabilities	(206)	—
Change in other assets, net	(1,790)	(865)
Cash provided by operating activities	$20,237	$27,441
Cash flows from investing activities:		
Capital expenditures	(58,385)	(72,538)
Acquisition	(11,000)	—
Proceeds from sale of mineral interest and equipment	1,389	522
Distribution from Medusa Spar LLC	616	1,120
Cash used in investing activities	$(67,380)	$(70,896)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	31,000	10,000
Payments on senior secured revolving credit facility	(41,000)	—
Redemption of 13% senior notes	—	(10,225)
Issuance of preferred stock	70,090	—
Payment of preferred stock dividends	(680)	—
Taxes paid related to exercise of employee stock options	—	(2)
Cash provided by (used in) financing activities	$59,410	$(227)
Net change in cash and cash equivalents	12,267	(43,682)
Beginning of period cash and cash equivalents	1,139	43,795

End of period cash and cash equivalents	$13,406	$113

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.)

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 crude oil and natural gas company, which since 1950 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. To date, 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.

The Company’s properties and operations are geographically concentrated onshore in Texas and Louisiana and the offshore waters of the Gulf of Mexico.

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 noted the items 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.

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Note 2 - Property Disclosures and Operating Leases

In April 2012, the Company took delivery of a drilling rig for a term of two years to support its horizontal drilling program in the Permian Basin, and on August 1, 2013, the Company contracted an additional drilling rig for a one year term. Lease cost recorded during the three and six months ended June 30, 2013 was $2,280 and $4,551, respectively. Lease payments will approximate $12,601 in 2013 (with $8,050 remaining at June 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 $5,055 in 2013 and $4,530 in 2014.

On June 1, 2013, the Company acquired approximately 2,468 gross (2,186 net) acres in Reagan County, 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).

Note 3 - Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
(a) Net income (loss) available to common shareholders	$78	$3,799	$(722)	$4,287
(b) Weighted average shares outstanding	40,089	39,399	39,941	39,375
Dilutive impact of stock options	—	7	—	14
Dilutive impact of restricted stock	234	749	—	815
(c) Weighted average shares outstanding for diluted net income (loss) per share	40,323	40,155	39,941	40,204
Basic net income (loss) per share (a/b)	$0.00	$0.10	$(0.02)	$0.11
Diluted net income (loss) per share (a/c)	$0.00	$0.09	$(0.02)	$0.11
The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:				
Stock options	52	67	52	52
Restricted stock	267	1,013	267	1,013

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	June 30, 2013	December 31, 2012
Principal components:		

Credit Facility	$—	$10,000
13% Senior Notes due 2016, principal	96,961	96,961
Total principal outstanding	96,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	12,092	13,707
Total carrying value of borrowings	$109,053	$120,668

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Senior Secured Revolving Credit Facility (the "Credit Facility")

As of June 30, 2013, the Company's $200,000 Credit Facility had an associated borrowing base of $75,000 and a maturity of March 15, 2016. 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 $5.5 million per quarter, so long 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 June 30, 2013, no balance was outstanding on the Credit Facility as a portion of the proceeds from the preferred stock offering was used to repay the balance then outstanding. The Credit Facility has an interest rate 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

The Senior Notes' 13% interest coupon 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 6/30/2013	Carrying Value at 6/30/2013	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	$19,415	$12,092	$1,615	$1,684

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 June 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

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.

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.

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.

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 June 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	Jul13 - Dec13	Not Designated
Natural gas	Put Option	91	MMbtu	$3.00	n/a	Jul13 - Dec13	Not Designated
Crude oil	Swap	40	Bbls	n/a	$101.30	Jul13 - 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

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	06/30/13	12/31/12	06/30/13	12/31/12	06/30/13	12/31/12
Natural gas	Current	Fair market value of derivatives	$—	$—	$(106)	$(125)	$(106)	$(125)

Natural gas	Non-current	Other long-term liabilities	—	—	(38)	(116)	(38)	(116)
Crude oil	Current	Fair market value of derivatives	1,647	1,674	—	—	1,647	1,674
Crude oil	Non-current	Other long-term assets	428	250	—	—	428	250
	Totals		$2,075	$1,924	$(144)	$(241)	$1,931	$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 June 30, 2013:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of hedging contracts	$2,330	$(683)	$1,647
Long-term assets: Fair value of hedging contracts	852	(424)	428
Current liabilities: Fair value of hedging contracts	(789)	683	(106)
Long-term liabilities: Fair value of hedging contracts	(462)	424	(38)

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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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. Any derivative contract not designated as an accounting hedge is carried at its fair value on the balance sheet with both realized and unrealized (mark-to-market) gains or losses on these derivatives 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Natural gas derivatives				
Realized gain (loss), net	$(156)	$—	$(107)	$—
Unrealized gain (loss), net	485	(331)	97	(331)
Sub-total gain (loss), net	$329	$(331)	$(10)	$(331)
Crude oil derivatives				
Realized gain, net	$849	$—	$1,422	$—
Unrealized gain, net	803	3,836	151	3,906
Sub-total gain, net	$1,652	$3,836	$1,573	$3,906
Total gain on derivative instruments, net	$1,981	$3,505	$1,563	$3,575

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Amount of gain reclassified from OCI into income (effective portion)	$—	$512	$—	$512
Amount of gain recognized in income (ineffective portion and amount excluded from effectiveness testing)	—	92	—	322

Subsequent Event: Derivative contracts executed subsequent to June 30, 2013 include the following:

Commodity	Instrument	Period

		Average Notional Volumes per Month	Quantity Type	Put/Call Price	Fixed-Price Swap		Designation under ASC 815
Crude oil	Swap	18	Bbls	n/a	$102.08	Sep13 - Dec13	Not Designated
Crude oil	Swap	9	Bbls	n/a	$94.58	Jan14 - Dec14	Not Designated

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 6 - Fair Value Measurements

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

Fair value of financial instruments

Cash, cash equivalents, 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:

	June 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$—	$—	$10,000	$10,000
13% Senior Notes due 2016 (1)	109,053	101,615	110,668	100,112
Total	$109,053	$101,615	$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 $12,092 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.

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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 June 30, 2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$1,647	$—	$1,647
Derivative financial instruments - non-current	Other long-term assets	—	428	—	428
Sub-total assets		—	2,075	—	2,075
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	$—	$106	$—	$106
Derivative financial instruments - non-current	Other long-term liabilities	—	38	—	38
Sub-total liabilities	Other long-term liabilities	—	144	—	144
Total		$—	$1,931	$—	$1,931

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 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 six months ended June 30, 2013, including upward revisions of $360, 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 from 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 six months ended June 30, 2013 and 2012 was 109% and 30%, respectively. The 109% effective tax rate for the six months ended June 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 June 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.

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Note 8 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations activity for the six months ended June 30, 2013:

Asset retirement obligations at January 1, 2013	$13,301	
Accretion expense	1,098	
Liabilities incurred	572	
Liabilities settled	(397	)
Revisions to estimate	(1,176	)
Asset retirement obligations at end of period	13,398	
Less: Current asset retirement obligations	6,223	
Long-term asset retirement obligations at June 30, 2013	$7,175	

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 June 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.

Note 9 - Equity Transactions

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.

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-K 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 possible 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 in order to provide a multi-year, low-risk drilling program in both crude oil and natural gas basins. To date, 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 furtherance of this strategy, in April 2013, we announced our intention to evaluate alternatives with respect to a potential sale of our interests in the Medusa field, our remaining deepwater asset.

Recent key accomplishments and development progress:

- In May, we successfully completed a $75 million Preferred Stock offering, which provided us with $70 million of net proceeds to accelerate the development of our Permian acreage and to retire the balance on our Credit Facility, leaving $75 million of available borrowing capacity on the Credit Facility.

- In June, we expanded our acreage position in the Permian Basin with the acquisition of 2,468 gross (2,186 net) acres in the southern portion of the Midland Basin for approximately $11 million. The properties acquired were producing approximately 145 net Boe per day at the time of acquisition.

- During August, we increased our capital budget by 36% to $170 million with approximately 90% 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. As a result of this budget increase, we expect to increase the total number of Permian wells planned to be drilled in 2013 to 31 gross wells, including 22 horizontal wells (completion of 17 gross wells) and nine vertical wells (completion of eight gross wells) .

- On August 1, 2013, we accepted delivery of an additional horizontal drilling rig under a one-year contract to support our expanded drilling program.

- To date in 2013, we continue to execute our horizontal drilling program (gross production data provided):

Two recent Wolfcamp B shale wells in the East Bloxom field produced at a peak (24-hour) rate of 1,258 Boe per day and an average peak 30-day rate of 634 Boe per day. Since commencing program development of this field in 2012, we have drilled seven wells with an average lateral length of 7,000 feet and completed four wells with demonstrated average peak initial (24-hour) rates of 1,031 Boe per day.

At our Taylor Draw field, we placed one well targeting the lower Wolfcamp B shale on production. The well produced at a 24-hour rate of 860 Boe per day. We also completed three additional wells in the upper Wolfcamp

B zone that are in the process of flowing back. The average lateral length for these four drill wells and an additional well completed in the first quarter of 2013 is 4,700 feet.

Also during 2013, we continue to execute our vertical Wolfberry drilling program with positive initial results. In our Pecan Acres field, our first well to simultaneous complete multiple zones down to the Woodford shale produced at a gross peak initial (24-hour) production rate of 543 Boe per day.

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

Overview and Outlook

Production and highlights of our operations include:

	Net Production (MBoe) Three Months Ended June 30,			
	2013	2012	Change	% Change
Onshore - Permian Basin:				
Southern Portion	122	85	37	44 %
Central Portion	48	57	(9)	(16)%
Total Permian	170	142	28	20 %
Offshore - Deepwater Properties				
Medusa	73	90	(17)	(19)%
Habanero	—	40	(40)	(100)%
Total Deepwater	73	130	(57)	(44)%
Other:				
Haynesville Shale	7	17	(10)	(59)%
Gulf of Mexico shelf	79	85	(6)	(7)%
Total Other	86	102	(16)	(16)%
Total	329	374	(45)	(12)%

	Net Production (MBoe) Six Months Ended June 30,			
	2013	2012	Change	% Change
Onshore - Permian Basin:				
Southern Portion	216	162	54	33 %
Central Portion	98	94	4	4 %
Total Permian	314	256	58	23 %
Offshore - Deepwater Properties				
Medusa	178	225	(47)	(21)%
Habanero	—	81	(81)	(100)%
Total Deepwater	178	306	(128)	(42)%
Other:				
Haynesville Shale	14	23	(9)	(39)%
Gulf of Mexico shelf	152	181	(29)	(16)%
Total Other	166	204	(38)	(19)%
Total	658	766	(108)	(14)%

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

	Crude Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	118	95.23	11	4.8
Royalty interest	3	0.10	2	0.08

Total	121	95.33	13	4.88

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

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 August 5, 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, in addition to our ongoing vertical Wolfberry program. The following table summarizes the Company's drilling progress in the Permian Basin for the six months ended June 30, 2013:

	Drilled		Completed (a)	
	Gross	Net	Gross	Net
Southern portion:				
Horizontal wells	9	8.22	5	4.51
Central portion:				
Vertical wells	3	1.75	4	2.29
Horizontal wells	—	—	—	—
Total central portion	3	1.75	4	2.29
Northern portion:				
Vertical wells	—	—	1	0.75
Horizontal wells	—	—	1	0.75
Total northern portion	—	—	2	1.50
Total	12	9.97	11	8.30

(a) Completions include wells drilled prior to the first half of 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 six months ended June 30, 2013, we drilled nine gross horizontal wells, with an average lateral length of over 6,600 feet, targeting either the Wolfcamp A or Wolfcamp B formations, and we fracture stimulated five gross horizontal wells targeting the Wolfcamp formation. As of June 30, 2013, we had five gross horizontal wells awaiting fracture stimulation.

During the second quarter of 2013, we acquired 2,468 gross (2,186 net) acres and seven gross vertical wells in southern Reagan County, Texas on which we intend to initiate drilling with two gross horizontal wells and two gross vertical wells planned for 2013.

Based on our initial results and the results of other industry participants, we are planning to increase our level of horizontal drilling activity in 2013 in this portion of the Basin, drilling a total of 11 horizontal wells and two vertical wells. Given this level of sustained activity, we are drilling these wells from pads, and intend to incorporate batch completions as the year progresses in an effort to maximize capital efficiency and reduce overall drill and completion time.

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.

During the six months ended June 30, 2013, we drilled three gross vertical wells, recompleted one gross vertical well, and fracture stimulated three gross vertical wells. We currently have one gross vertical well awaiting fracture stimulation. 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. Our remaining 2013 drilling plans include an additional three vertical wells, though we may modify these plans based on the drilling results achieved. In addition, there has been a significant increase in horizontal Wolfcamp shale drilling in the areas surrounding our acreage position in Ector and Midland Counties. Based on the results of other industry participants, our remaining 2013 drilling plans will include two horizontal Wolfcamp shale wells on our Carpe Diem acreage.

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. During the six months ended June 30, 2013, we fracture stimulated one gross horizontal well targeting the Mississippian lime zone for evaluation. Due to difficulties in maintaining the drilling of the lateral in our target zone, the results from the well were inconclusive. We plan to drill a vertical well in Borden County to advance our evaluation of the acreage and provide additional information regarding the Mississippian interval.

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 (where our current production is located), which significantly increases the risk associated with successful drilling activities in this area.

Offshore - Deepwater properties

Our net interest in the Medusa field, our remaining deepwater property, produced an average of 981 Boe per day during the six months ended June 30, 2013, approximately 88% being crude oil that receives pricing based on Mars crude. The Medusa platform was shut-in for 23 days during the second quarter of 2013 for planned construction activities on the West Delta 143 oil pipeline through which Medusa's production is transported. Production from the platform was fully restored on June 27, 2013, and as of August 5, 2013 was producing approximately 1,100 Boe, net.

As previously announced in April 2013 and in furtherance of our strategy to accelerate development of our onshore properties, we retained an advisor to assist with the potential sale of the Medusa property.

Other – Shale Gas (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 June 30, 2013, our Haynesville well was producing approximately 477 Mcf of natural gas per day. We currently have no drilling obligations related to this lease position.

Other – Gulf of Mexico shelf properties

During the six months ended June 30, 2013, these wells produced 152 MBoe, which accounted for 23% of our total production. We are in the process of plugging and abandoning our only remaining operated shelf property, Mobile Bay 908. 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 232 Boe per day of production for the second quarter.

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 $13.4 million increased by $12.3 million at June 30, 2013 compared to $1.1 million at December 31, 2012. The increase is attributable to proceeds from the preferred stock offering previously discussed in Note 9 and summarized below. As of June 30, 2013, the Company's liquidity position approximated $88.4 million inclusive of cash and cash equivalents and available borrowing capacity under our Credit facility.

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 the underwriting commissions and offering expenses. The first dividend date for the Preferred Stock was June 30, 2013, and these dividends were paid on July 1, 2013 in the amount of $0.7 million for the stub period beginning with the issuance on May 30, 2013 through the first dividend date.

As of June 30, 2013, our $200 million Credit Facility had an associated borrowing base of $75 million and a maturity 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.

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

As of June 30, 2013, no balance was outstanding on the Credit Facility as a portion of the proceeds from the Preferred Stock offering was used to repay the balance then outstanding. The Credit Facility has an interest rate 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.

On May 10, 2013, we entered into the second amendment to our Fourth Amended and Restated Credit Agreement dated as of June 20, 2012 to allow us to pay quarterly Senior Unsecured Debt and Preferred Equity Dividends (as defined in the Credit Facility) of $5.5 million per quarter, so long as we are not in default under the Credit Facility. The amendment became effective with the receipt of a minimum of $30.0 million of net cash proceeds from a preferred equity offering, which in turn was used to pay down the facility.

At June 30, 2013, we had approximately $97 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly.

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 90% 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 31 gross wells including 22 horizontal wells and nine vertical wells. Components of the 2013 capital budget include (in millions):

Midland Basin	$142
Gulf of Mexico	11
Total budgeted capital expenditures	$153
Capitalized general and administrative costs	13
Capitalized interest and other	4
Total budgeted capitalized expenses	$17
Total operational budget	170
Acquisition - Southern Midland Basin	11
Total capital expenditures	$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 during the year.

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

Southern Midland Basin	$43
Central Midland Basin	4
Northern Midland Basin	3
Total capital expenditures	$50

Capitalized general and administrative costs	5
Capitalized interest and other	2
Total capitalized expenses	$7
Total operational expenditures	57
Acquisition - Southern Midland Basin	11
Total capital expenditures	$68

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Summary cash flow information is provided as follows:

Operating activities. For the six months ended June 30, 2013, net cash provided by operating activities decreased $7.2 million to $20.2 million, from $27.4 million for the same period in 2012. The decrease relates primarily to a $9.4 million decrease in revenue stemming from a 12% decrease in equivalent production, which was partially offset by a 2% increase in price per equivalent unit produced and lower operating expenses, which were in line with our lower production. Realized prices and production volumes are discussed below within Results of Operations.

Investing activities. For the six months ended June 30, 2013, net cash used in investing activities was $67.4 million as compared to $70.9 million for the same period in 2012. The $3.5 million decrease is primarily attributable to the $15 million acquisition of additional acreage in Borden County located in the northern portion of the Permian Basin during 2012 offset by the $11.0 million acreage acquisition highlighted above and discussed in Note 2.

Financing activities. For the six months ended June 30, 2013, net cash provided by financing activities was $59.4 million compared to cash used in financing activities of $0.2 million during the same period of 2012. The $59.6 million increase relates primarily to the $70.1 million net proceeds from the previously discussed preferred stock offering reduced 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 June 30,			
	2013	2012	Change	% Change
Net production:				
Crude oil (MBbls)	198	223	(25)	(11)%*
Natural gas (MMcf)	787	902	(115)	(13)%*
Total production (MBoe)	329	374	(45)	(12)%
Average daily production (MBoe)	3.6	4.1	(0.5)	(12)%
Average realized sales price (a):				
Crude oil (Bbl)	$96.27	$98.78	$(2.51)	(3)%
Natural gas (Mcf)	$4.70	$3.65	$1.05	29%
Average realized sales price on an equivalent basis (Boe)	$69.18	$67.85	$1.33	2%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$19,061	$22,073	$(3,012)	(14)%
Natural gas revenue	3,699	3,287	411	13%
Total	$22,760	$25,360	$(2,600)	(10)%
Additional per Boe data:				
Average realized sales price	$69.18	$67.85	$1.33	2%
Lease operating expense	16.36	14.03	2.33	17%
Production taxes	2.09	1.54	0.55	36%
Operating margin	$50.73	$52.28	$(1.55)	(3)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$32.38	$31.69	$0.69	2%
General and administrative	13.81	11.70	2.11	18%

(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	$94.22	$93.49	$0.73	1%
Basis differential and quality adjustments	2.52	3.68	(1.16)	(32)%
Transportation	(0.47)	(0.68)	0.21	(31)%
Hedging	—	2.29	(2.29)	(100)%
Average realized price per Bbl of crude oil	$96.27	$98.78	(2.51)	(3)%
Average NYMEX price per million British thermal units ("MMBtu")	$4.01	$2.35	$1.66	71%
Basis differential, quality and Btu adjustments	0.69	1.30	(0.61)	(47)%
Average realized price per Mcf of natural gas	$4.70	$3.65	$1.05	29%

* Please refer to the Crude oil and Natural gas revenue discussions included below for an explanation of the production declines.

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

	Six Months Ended June 30,			
	2013	2012	Change	% Change
Net production:				
Crude oil (MBbls)	404	465	(61)	(13)%*
Natural gas (MMcf)	1,525	1,806	(281)	(16)%*
Total production (MBoe)	658	766	(108)	(14)%
Average daily production (MBoe)	3.6	4.2	(0.6)	(14)%
Average realized sales price (a):				
Crude oil (Bbl)	$95.55	$102.86	$(7.31)	(7)%
Natural gas (Mcf)	$4.39	$3.78	$0.61	16%
Average realized sales price on an equivalent basis (Boe)	$68.85	$71.36	$(2.51)	(4)%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$38,601	$47,822	$(9,221)	(19)%
Natural gas revenue	6,700	6,833	(133)	(2)%
Total	$45,301	$54,655	$(9,354)	(17)%
Additional per Boe data:				
Average realized sales price	$68.85	$71.36	$(2.51)	(4)%
Lease operating expense	16.93	19.07	(2.14)	(11)%
Production taxes	1.86	1.46	0.40	27%
Operating margin	$50.06	$50.83	$(0.77)	(2)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$32.97	$31.38	$1.59	5%
General and administrative	12.59	12.28	0.31	3%

(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	$94.30	$98.21	$(3.91)	(4)%
Basis differential and quality adjustments	1.81	4.33	(2.52)	(58)%
Transportation	(0.56)	(0.78)	0.22	(28)%
Hedging	—	1.10	(1.10)	(100)%
Average realized price per Bbl of crude oil	$95.55	$102.86	$(7.31)	(7)%
Average NYMEX price per million British thermal units ("MMBtu")	$3.75	$2.43	$1.32	54%
Basis differential, quality and Btu adjustments	0.64	1.35	(0.71)	(53)%
Average realized price per Mcf of natural gas	$4.39	$3.78	$0.61	16%

* Please refer to the Crude oil and Natural gas revenue discussions included below for an explanation of the production declines.

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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 June 30, 2011	$29,087	$7,747	$36,834
Volume increase (decrease)	$(5,455)	$(2,713)	$(8,168)
Price increase (decrease)	(2,071)	(1,747)	(3,818)
Impact of hedges	512	—	512
Net increase (decrease) in 2012	(7,014)	(4,460)	(11,474)
Revenues for the three-months ended June 30, 2012	$22,073	$3,287	$25,360
Volume increase (decrease)	$(2,475)	$(419)	$(2,894)
Price increase (decrease)	(1,386)	987	(399)
Impact of hedges	849	(156)	693
Net increase (decrease) in 2013	(3,012)	412	(2,600)
Revenues for the three-months ended June 30, 2013	$19,061	$3,699	$22,760

(in thousands)	Crude Oil	Natural Gas	Total
Revenues for the six-months ended June 30, 2011	$47,891	$14,392	$62,283
Volume increase (decrease)	$(1,070)	$(4,872)	$(5,942)
Price increase (decrease)	489	(2,687)	(2,198)
Impact of hedges	512	—	512
Net increase (decrease) in 2012	(69)	(7,559)	(7,628)
Revenues for the six-months ended June 30, 2012	$47,822	$6,833	$54,655
Volume increase (decrease)	$(6,273)	$(1,063)	$(7,336)
Price increase (decrease)	(4,370)	1,038	(3,332)
Impact of hedges	1,422	(108)	1,314
Net increase (decrease) in 2013	(9,221)	(133)	(9,354)
Revenues for the six-months ended June 30, 2013	$38,601	$6,700	$45,301

Crude oil revenue

Crude oil revenues decreased 14% to $19.1 million for the three months ended June 30, 2013 compared to revenues of $22.1 million for the same period of 2012. Contributing to the decrease in crude oil revenue was an 11% decrease in production compounded by a 3% decrease in realized crude oil prices. Production decreased to 198 thousand barrels ("MBbls") during the second quarter of 2013 compared to production of 223 MBbls during the same period in 2012. The decrease in production was primarily attributable to the sale of our deepwater Habanero field in the fourth quarter of 2012, which produced 31 MBbls during the second quarter of 2012. Also contributing to the decrease was 23 days of down time at our Medusa field for scheduled downstream pipeline maintenance. Additionally, normal and expected declines further reduced oil production. Partially offsetting these decreases in our Gulf of Mexico and other properties was a 21 MBbls increase in production from our Permian properties.

Crude oil revenues decreased 19% to $38.6 million for the six months ended June 30, 2013, compared to revenues of $47.8 million for the same period of 2012. The average oil price realized decreased 7%, while total production also decreased 13%. Production decreased to 404 MBbls for the six month period of 2013 compared to production of 465 MBbls during the same period in 2012. The decrease in production was primarily attributable to the sale of Habanero, maintenance at the Medusa field and the normal and expected declines, which were previously discussed above.

Natural gas revenue

Natural gas revenues of $3.7 million increased 13% during the three months ended June 30, 2013 as compared to natural gas revenues of $3.3 million for the same period of 2012. The increase primarily relates to a 29% increase in the average price realized. Compared to the second quarter of 2012, natural gas volumes decreased 13% primarily due to the sale of Habanero, from which we produced 52 million cubic feet ("MMcf") of natural gas during the second quarter of 2012, and due to a decline in production from our Haynesville well, which produced 66 MMcf less during the second quarter of 2013 compared to the same quarter of 2012. Other normal and expected declines, primarily from our Gulf of Mexico shelf properties, also pushed overall production lower. These production decreases were partially offset by a 49 MMcf increase from our Permian properties and by a 72 MMcf increase from our East Cameron 257 field, which returned to production in May of 2013.

Natural gas revenues of $6.7 million remained relatively flat during the six months ended June 30, 2013, as compared to natural gas revenues of $6.8 million for the same period of 2012. The average natural gas price realized increased 16%, while total production decreased 16%. Production decreased 281 MMcf for the six month period of 2013 compared to the same period in 2012. The decrease in production was primarily attributable to normal and expected declines in our Gulf of Mexico properties and the sale of our deepwater Habanero field in the fourth quarter of 2012, which together produced 1,136 MMcf of natural gas during the six months ended June 30, 2012. Also contributing to the decline was down time at our Medusa field along with normal and expected declines in natural gas production from our Haynesville well.

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 June 30,							
		Per		Per	Total Change		Boe Change	
	2013	Boe	2012	Boe	$	%	$	%
Lease operating expenses	$5,384	$16.36	$5,246	$14.03	$138	3 %	$2.33	17 %
Production taxes	687	2.09	575	1.54	112	19 %	0.55	36 %
Depreciation, depletion and amortization	10,654	32.38	11,844	31.69	(1,190)	(10)%	0.69	2 %
General and administrative	4,545	13.81	4,374	11.70	171	4 %	nm	nm
Accretion expense	533	1.62	562	1.50	(29)	(5)%	nm	nm

(in thousands except per unit data)	Six Months Ended June 30,							
		Per		Per	Total Change		Boe Change	
	2013	Boe	2012	Boe	$	%	$	%
Lease operating expenses	$11,142	$16.93	$13,484	$17.60	$(2,342)	(17)%	$(0.67)	(4)%
Production taxes	1,226	1.86	1,122	1.47	104	9 %	0.39	27 %
Depreciation, depletion and amortization	21,696	32.97	24,033	31.38	(2,337)	(10)%	1.59	5 %
General and administrative	8,284	12.59	9,405	12.28	(1,121)	(12)%	nm	nm
Accretion expense	1,098	1.67	1,135	1.48	(37)	(3)%	nm	nm

*nm = not meaningful

Lease operating expenses ("LOE")

LOE, while flat on an overall basis for the three months ended June 30, 2013 increased by 17% to $16.36 compared to $14.03 for the same period in 2012. The increase primarily relates to $0.6 million, or $1.90 per Boe, in workover costs associated with our Medusa field with the remainder related to growth in the number of wells now producing in our Permian Basin properties. These increases were 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, on a total basis it decreased by $2.3 million for the six months ended June 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, of 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 six months ended June 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 for the three months ended June 30, 2013 and compared to the same period of 2012 decreased 10%. The decrease is primarily related to the 12% drop in total production offset by a 2% rate increase in the second quarter of 2013 compared to the same quarter of 2012. DD&A for the six months ended June 30, 2013 and compared to the same period of 2012 decreased 10%. The decrease is primarily related to the 14% decline in total production offset by a 5%

rate increase during the the first six months of 2013 compared the same period of 2012.

General and administrative ("G&A")

G&A, net of amounts capitalized ("G&A, net"), remained relatively flat for the three months ended June 30, 2013 compared to the same period of 2012. Conversely, for the six months ended June 30, 2013 and as compared to the same period of 2012, G&A, net, decreased $1.1 million primarily due to a $1.3 million downward revision for the mark-to-market adjustment of certain liability-based incentive compensation instruments, partially offset by a $0.3 million increase in employee related expenses.

Accretion expense

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

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

Other Income and Expenses

(in thousands)	Three Months Ended June 30,			
	2013	2012	$ Change	% Change
Interest expense	$1,537	$2,384	$(847)	(36)%
Gain on early extinguishment of debt	—	(1,366)	1,366	100%
Gain on derivative contracts	(1,981)	(3,505)	1,524	43%
Other income, net	(44)	(157)	113	(72)%
Income tax expense	663	1,610	(947)	(59)%
Equity in earnings of Medusa Spar LLC	(24)	6	(30)	(500)%
Preferred stock dividends	680	—	680	100%
(in thousands)	Six Months Ended June 30,			
	2013	2012	$ Change	% Change
Interest expense	$3,052	$4,961	$(1,909)	(38)%
Gain on early extinguishment of debt	—	(1,366)	1,366	(100)%
Gain on derivative contracts	(1,563)	(3,575)	2,012	(56)%
Other income, net	(89)	(461)	372	(81)%
Income tax expense	494	1,754	(1,260)	(72)%
Equity in earnings of Medusa Spar LLC	(3)	124	(127)	(102)%
Preferred stock dividends	680	—	680	100%

Interest expense

Interest expense incurred during the three and six months ended June 30, 2013 decreased $0.8 million and $1.9 million, respectively, compared to the same periods of 2012 and is primarily related to an increase in capitalized interest of $0.8 million and $1.7 million for the comparative three and six month periods, respectively. The additional capitalized interest relates to a $49.4 million increase in the 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.

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

As discussed in Note 7, the unusually high effective tax rate ("ETR") for the three months ended June 30, 2013 relates to the treatment of 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 expect the full-year 2013 ETR to approximate 30%, excluding discrete items. See Note 7 for a discussion of our effective tax rates for the periods presented above.

Preferred stock dividends

On May 30, 2013, the Company issued $75.0 million of 10.0% Series A Cumulative Preferred Stock (the “Preferred Stock”). The first dividend date for the Preferred Stock was June 30, 2013, and these dividends were paid on June 28, 2013 in the amount of $0.7 million for the stub period beginning with the issuance on May 30, 2013 through the first dividend date.

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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 August 5, 2013, we have commodity contracts covering approximately 55% and 30% of our internally forecasted proved developed producing crude oil and natural gas production, respectively, from July 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 June 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 June 30, 2013, the majority of the Company's debt consisted of its fixed-rate 13% Senior Notes. Similarly, the Company's Preferred Stock also has a fixed dividend rate of 10%. 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 no borrowings outstanding at June 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 additional information regarding the Company's Credit Facility and other borrowings at June 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 June 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	Amendment No. 2 to the Fourth Amended and Restated Credit Agreement dated as of May 10, 2013 between Callon Petroleum Company, Callon Petroleum Operating Company, the “Lenders” described therein, and Regions Bank, as Administrative Agent (incorporated by reference to Exhibit 10.1 of the Company’s Report on Form 8-K filed May 21, 2013).
10.2	Underwriting Agreement dated as of May 22, 2013 between Callon Petroleum Company and Janney Montgomery Scott LLC, Sterne, Agee & Leach, Inc. and MLV & Co. LLC as representative of the several underwriters named therein (incorporated by reference to Exhibit 1.1 of the Company’s Report on Form 8-K filed May 28, 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	August 8, 2013
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	August 8, 2013