CALLON PETROLEUM CO
Form 10-Q
May 09, 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: March 31, 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 May 1, 2013 there were outstanding 39,867,287 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 par value per share data)

	March 31, 2013 Unaudited	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$1,379	$1,139
Accounts receivable	15,024	15,608
Fair market value of derivatives	1,511	1,674
Other current assets	645	1,502
Total current assets	18,559	19,923
Oil and natural gas properties, full-cost accounting method:		
Evaluated properties	1,533,739	1,497,010
Less accumulated depreciation, depletion and amortization	(1,307,307)	(1,296,265)
Net oil and natural gas properties	226,432	200,745
Unevaluated properties excluded from amortization	60,976	68,776
Total oil and natural gas properties	287,408	269,521
Other property and equipment, net	9,898	10,058
Restricted investments	3,800	3,798
Investment in Medusa Spar LLC	8,260	8,568
Deferred tax asset	64,542	64,383
Other assets, net	1,998	1,922
Total assets	$394,465	$378,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$34,457	$36,016
Asset retirement obligations	2,802	2,336
Fair market value of derivatives	537	125
Total current liabilities	37,796	38,477
13% Senior Notes:		
Principal outstanding	96,961	96,961
Deferred credit, net of accumulated amortization of $18,599 and $17,800, respectively	12,908	13,707
Total 13% Senior Notes	109,869	110,668
Senior secured revolving credit facility	27,000	10,000
Asset retirement obligations	11,496	10,965
Other long-term liabilities	2,108	2,092
Total liabilities	188,269	172,202
Stockholders' equity:		
Preferred Stock, $0.01 par value, 2,500,000 shares authorized;	—	—
Common stock, $0.01 par value, 60,000,000 shares authorized; 39,843,601 and 39,800,548 shares outstanding at March 31, 2013 and December 31,	399	398

2012, respectively		
Capital in excess of par value	329,140	328,116
Retained deficit	(123,343)	(122,543)
Total stockholders' equity	206,196	205,971
Total liabilities and stockholders' equity	$394,465	$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 March 31,	
	2013	2012
Operating revenues:		
Crude oil sales	$19,540	$25,749
Natural gas sales	3,001	3,545
Total operating revenues	22,541	29,294
Operating expenses:		
Lease operating expenses	5,758	8,237
Production taxes	539	547
Depreciation, depletion and amortization	11,042	12,189
General and administrative	3,739	5,031
Accretion expense	565	574
Total operating expenses	21,643	26,578
Income from operations	898	2,716
Other (income) expenses:		
Interest expense	1,515	2,577
Loss (gain) on derivative contracts	418	(70)
Other income, net	(45)	(305)
Total other expenses, net	1,888	2,202
Income (loss) before income taxes	(990)	514
Income tax expense (benefit)	(169)	144
Income (loss) before equity in earnings of Medusa Spar LLC	(821)	370
Equity in earnings of Medusa Spar LLC	21	118
Net income (loss) available to common shares	$(800)	$488
Net income (loss) per common share:		
Basic	$(0.02)	$0.01
Diluted	$(0.02)	$0.01
Shares used in computing net income (loss) per common share:		
Basic	39,793	39,351
Diluted	39,793	40,254

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

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

	Three Months Ended March 31,	
	2013	2012
Net income (loss)	$(800)	$488
Other comprehensive (loss) income:		
Change in fair value of derivatives designated as hedges, net of tax (See Note 5)	—	(1,470)
Total comprehensive income (loss)	$(800)	$(982)

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

Callon Petroleum Company
Consolidated Statements of Cash Flows
(Unaudited, in thousands)

	Three Months Ended March 31, 2013	2012
Cash flows from operating activities:		
Net (loss) income	$(800)	$488
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation, depletion and amortization	11,393	12,486
Accretion expense	565	574
Amortization of non-cash debt related items	111	122
Amortization of deferred credit	(799)	(811)
Equity in earnings of Medusa Spar LLC	(21)	(118)
Deferred income tax (benefit) expense	(169)	144
Unrealized loss (gain) on derivative contracts	1,039	(299)
Non-cash expense related to equity share-based awards	580	442
Change in the fair value of liability share-based awards	(195)	907
Payments to settle asset retirement obligations	(396)	(630)
Changes in current assets and liabilities:		
Accounts receivable	1,333	(3,177)
Other current assets	857	1,075
Current liabilities	158	(730)
Change in natural gas balancing receivable	(63)	1
Change in natural gas balancing payable	10	50
Change in other long-term liabilities	(206)	—
Change in other assets, net	(522)	(174)
Cash provided by operating activities	$12,875	$10,350
Cash flows from investing activities:		
Capital expenditures	(30,089)	(45,481)
Proceeds from sale of mineral interest and equipment	114	506
Distribution from Medusa Spar LLC	340	758
Cash used in investing activities	$(29,635)	$(44,217)
Cash flows from financing activities:		
Borrowings on senior secured revolving credit facility	17,000	—
Taxes paid related to exercise of employee stock options	—	(2)
Cash provided by (used in) financing activities	$17,000	$(2)
Net change in cash and cash equivalents	240	(33,869)
Beginning of period cash and cash equivalents	1,139	43,795
End of period cash and cash equivalents	$1,379	$9,926

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

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 per-share, per-hedge, well and acreage 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 per-share, per-hedge, well and acreage 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

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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 February 2012, we contracted a drilling rig for a term of two years to support our horizontal drilling program in the Permian Basin, which was delivered to the Company and began operations in April 2012. Lease cost recorded during the three months ended March 31, 2013 was $2,271. Lease payments will approximate $9,235 in 2013 (with $6,964 remaining at March 31, 2013) and $2,277 in 2014. The agreement includes 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 $4,125 in 2013 and $1,350 in 2014.

Note 3 - Earnings Per Share

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

	Three Months Ended March 31,	
	2013	2012
(a) Net income (loss)	$(800)	$488
(b) Weighted average shares outstanding	39,793	39,351
Dilutive impact of stock options	—	20
Dilutive impact of restricted stock	—	883
(c) Weighted average shares outstanding for diluted net income (loss) per share	39,793	40,254
Basic net income (loss) per share (a/b)	$(0.02)	$0.01
Diluted net income (loss) per share (a/c)	$(0.02)	$0.01
The following underlying shares associated with the following instruments were excluded from the diluted EPS calculation because their effect would be anti-dilutive:		
Stock options	67	67
Restricted stock	40	—

Note 4 – Borrowings

The Company’s borrowings consisted of the following at:

	March 31, 2013	December 31, 2012
Principal components:		
Credit Facility	$27,000	$10,000
13% Senior Notes due 2016, principal	96,961	96,961
Total principal outstanding	123,961	106,961
Non-cash components:		
13% Senior Notes due 2016 unamortized deferred credit	12,908	13,707
Total carrying value of borrowings	$136,869	$120,668

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

The Company's $200,000 Credit Facility had an associated borrowing base at March 31, 2013 of $65,000 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.

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In April 2013, the Credit Facility's borrowing base was increased $10,000 from $65,000 to $75,000.

As of March 31, 2013, the balance outstanding on the Credit Facility was $27,000 with an interest rate of 3.1%, 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. As of May 6, 2013, the balance outstanding on the Credit Facility was $38,000 as the Company drew an additional $11,000 in support of the Company's ongoing capital development program.

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 3/31/2013	Carrying Value at 3/31/2013	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	$18,599	$12,908	$799	$2,500

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 March 31, 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. The Company monitors counterparty creditworthiness on an ongoing basis; however, 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.

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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 March 31, 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	Apr13 - Dec13	Not Designated
Natural gas	Put Option	91	MMbtu	$3.00	n/a	Apr13 - Dec13	Not Designated
Crude oil	Swap	40	Bbls	n/a	$101.30	Apr13 - 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	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	03/31/13	12/31/12	03/31/13	12/31/12	03/31/13	12/31/12
Natural gas	Current	Fair market value of derivatives	$—	$—	$(537)	$(125)	$(537)	$(125)
Natural gas	Non-current	Other long-term liabilities	—	—	(92)	(116)	(92)	(116)
Crude oil	Current	Fair market value of derivatives	1,511	1,674	—	—	1,511	1,674
Crude oil	Non-current	Other long-term assets	—	250	—	—	—	250
Crude oil	Non-current	Other long-term liabilities	—	—	(239)	—	(239)	—
	Totals		$1,511	$1,924	$(868)	$(241)	$643	$1,683

The Company's derivative contracts are subject to netting arrangements. The Company presents the fair values of its derivative contracts on the balance sheet 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 March 31, 2013:

	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
Current assets: Fair value of hedging contracts	$2,347	$(836)	$1,511
Long-term assets: Fair value of hedging contracts	286	(286)	—
Current liabilities: Fair value of hedging contracts	(1,373)	836	(537)
Long-term liabilities: Fair value of hedging contracts	(617)	286	(331)

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

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 March 31,	
	2013	2012
Natural gas derivatives		
Realized gain (loss), net	$49	$—
Unrealized gain (loss), net	(388)	—
Sub-total gain (loss), net	$(339)	$—
Crude oil derivatives		
Realized gain (loss), net	$573	$—
Unrealized gain (loss), net	(652)	70
Sub-total gain (loss), net	$(79)	$70
Total gain (loss) on derivative instruments, net	$(418)	$70

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 executed during 2011 and in effect during 2012 were designated as cash flow hedges. 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 are recorded as an increase or decrease in crude oil revenues. Both changes in fair value and cash settlements of ineffective derivative contracts are recognized as derivative expense (income).

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 March 31,	
	2013	2012
Amount of gain (loss) reclassified from OCI into income (effective portion)	$—	$—
Amount of gain (loss) recognized in income (ineffective portion and amount excluded from effectiveness testing)	—	230

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.

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

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

	March 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$27,000	$27,000	$10,000	$10,000
13% Senior Notes due 2016 (1)	$109,869	$100,839	$110,668	$100,112
Total	$136,869	$127,839	$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 $12,908 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 collars, natural gas and crude oil basis swaps, 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 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.

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

As of 3/31/2013	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current	Fair market value of derivatives	$—	$1,511	$—	$1,511
Derivative financial instruments - non-current	Other long-term assets	—	—	—	—
Sub-total assets		—	1,511	—	1,511
Liabilities					
Derivative financial instruments - current	Fair market value of derivatives	—	537	—	537
Derivative financial instruments - non-current	Other long-term liabilities	$—	$331	$—	$331
Sub-total liabilities	Other long-term liabilities	—	868	—	868
Total		$—	$643	$—	$643

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

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

The derivative fair values above are based on analysis of each contract.

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 three months ended March 31, 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.

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 three months ended March 31, 2013 and 2012 was 17% and 28%, respectively.

We have no liability for uncertain tax positions or any accrued interest or penalties as of March 31, 2013.

Note 8 - Asset Retirement Obligations

The following table summarizes the Company's asset retirement obligations activity for the three months ended March 31, 2013:

Asset retirement obligations at January 1, 2013	$13,301
Accretion expense	565
Liabilities incurred	569
Liabilities settled	(162)
Revisions to estimate	25
Asset retirement obligations at end of period	14,298
Less: Current asset retirement obligations	2,802
Long-term asset retirement obligations at March 31, 2013	$11,496

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 March 31, 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.

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.

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.

Overview and Outlook

Production and highlights of our operations include:

	Net Production (MBoe)			
	Three Months Ended March 31,			
	2013	2012	Change	% Change
Onshore - Permian Basin:				
Southern Portion	93	77	16	21 %
Central Portion	49	37	12	32 %
Total Permian	142	114	28	25 %
Offshore - Deepwater Properties				
Medusa	105	136	(31)	(23)%
Habanero	—	42	(42)	(100)%
Total Deepwater	105	178	(73)	(41)%
Other:				
Haynesville Shale	8	6	2	33 %
Gulf of Mexico shelf	73	94	(21)	(22)%
Total Other	81	100	(19)	(19)%
Total	328	392	(64)	(16)%

The following table sets forth productive wells as of March 31, 2013:

	Crude Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	108	87.18	10	4.3
Royalty interest	3	0.10	2	0.08
Total	111	87.28	12	4.38

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

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 38,127 gross (32,962 net) acres as of May 1, 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 three months ended March 31, 2013:

	Drilled		Completed	
	Gross	Net	Gross	Net
Southern portion:				
Vertical wells	—	—	—	—
Horizontal wells	4	3.95	1	1.00
Total southern portion	4	3.95	1	1.00
Central portion:				
Vertical wells	1	0.42	2	1.39
Horizontal wells	—	—	—	—
Total central portion	1	0.42	2	1.39
Northern portion:				
Vertical wells	—	—	—	—
Horizontal wells	—	—	1	0.75
Total northern portion	—	—	1	0.75
Total	5	4.37	4	3.14

Southern portion: We currently own approximately 7,785 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 three months ended March 31, 2013, we drilled three 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 two gross horizontal wells targeting the Wolfcamp formation. As of March 31, 2013, we had three gross horizontal wells awaiting fracture stimulation.

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 15 horizontal wells, an increase of 10 over the horizontal wells drilled in 2012. We also plan to drill one vertical well during the year. 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 3,560 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 three months ended March 31, 2013, we drilled one gross vertical well, recompleted one gross vertical well, and fracture stimulated two gross vertical wells. We currently have one gross vertical well awaiting fracture stimulation. In late 2012 our drilling program in the Pecan Acres and Carpe Diem fields targeted deeper intervals below the Atoka formation. Our future vertical drilling plans within the 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 seven 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. We are currently developing plans for the drilling of a horizontal evaluation well on our Carpe Diem acreage.

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

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 three months ended March 31, 2013, we fracture stimulated one gross horizontal well targeting the Mississippian lime zone. The well had a 24-hour peak oil rate of 136 barrels of oil per day (bopd) while simultaneously producing 2,000 barrels of water per day. The oil production rate quickly declined and stabilized at a rate of 10 to 15 barrels of oil per day while maintaining a high water production rate. We recently set a mechanical plug in an effort to isolate an oil producing zone in the Mississippian formation that we believe is above the source of the water production. We are continuing to evaluate the well's performance following this procedure.

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 1,163 Boe per day during the three months ended March 31, 2013, approximately 88% being crude oil that receives pricing based on Mars crude.

In furtherance of our strategy to accelerate development of our onshore properties, on April 29, 2013, we announced our retention of 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 430 net acre unit in the Haynesville shale play in Bossier Parish, Louisiana. As of March 31, 2013, our Haynesville well was producing approximately 524 Mcf of natural gas per day. We currently have no drilling obligations related to this lease position.

Other – Gulf of Mexico shelf properties

We own interests in 14 producing wells in eight crude oil and natural gas fields in the shelf area of the Gulf of Mexico. During the three months ended March 31, 2013, these wells produced 73 MBoe, which accounted for 22% 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 contributed an average of 175 Boe per day of production prior to being shut-in in November 2011, is expected to recommence once the Stingray Pipeline is brought back online, currently anticipated to occur in the second quarter of 2013.

Liquidity and Capital Resources

Historically, our primary sources of funding have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities and, periodically strategic divestitures.

Cash and cash equivalents of $1.4 million remained relatively flat at March 31, 2013 compared to $1.1 million at December 31, 2012.

Our $200 million Credit Facility had an associated borrowing base at March 31, 2013 of $65 million and a maturity of March 15, 2016. In April 2013, the Credit Facility's borrowing base was increased $10 million to $75 million. 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.

As of March 31, 2013, the balance outstanding on the Credit Facility was $27 million with an interest rate of 3.1%, 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. As of May 6, 2013, the balance outstanding on the Credit Facility was $38 million as the Company drew an additional $11 million in support of the Company's ongoing capital development program. Consequently, subsequent to the $10 million increase in the borrowing base net of addition draws on the Credit Facility, the Company's current liquidity position approximates $38.8 million.

At March 31, 2013, we had approximately $97 million principal amount of 13% Senior Notes due 2016 outstanding with interest payable quarterly.

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

2013 capital expenditures

For 2013, we designed a flexible capital spending program, which we plan to fund from cash on hand and cash flows from operations, in addition to borrowings under our Credit Facility. However, depending on economic conditions or the Company's operational results, our capital budget may be adjusted up or down during the year.

Our 2013 capital budget has been established at $125.0 million with over 90% of our budgeted operating expenditures (including drilling, completion, infrastructure, and plugging and abandonment) allocated to our Midland Basin operations. The 15% decrease in total capital from 2011 reflects our primary focus on drilling and completion activities in the Permian Basin and reduced emphasis on acreage acquisitions that were budgeted in 2012 to expand the Company's presence in the basin. Our budget includes further exploration and development of our Permian Basin properties with plans to complete approximately 24 gross wells including 15 horizontal wells and nine vertical wells.
Components of the 2013 capital budget include (in millions):

Midland Basin	$97
Gulf of Mexico	10
Total projected operations budget	107
Capitalized general and administrative costs	14
Capitalized interest and other	4
Total projected capital expenditures budget	$125

We believe that our liquidity position, 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. In addition to cash on hand, cash flows from operations and borrowings under our Credit Facility, we may source additional capital from term debt or preferred equity offerings, as well as the potential sale of our interest in Medusa and Medusa Spar LLC, to fund the potential acceleration in our onshore growth initiatives in the future.

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

The capital expenditures for the three months ended March 31, 2013 include the following (in millions):

Southern Midland Basin	$22
Northern Midland Basin	3
Leasehold acquisitions and seismic	1
Capitalized interest	1
Capitalized general and administrative costs allocated directly to exploration and development projects	3
Total capital expenditures	$30

Summary cash flow information is provided as follows:

Operating activities. For the three months ended March 31, 2013, net cash provided by operating activities increased $2.5 million to $12.9 million, from $10.4 million for the same period in 2012. The increase relates primarily to an overall decrease in operating expenses, which were in line with our lower production. Offsetting this increase was an 8% decrease in the price received for crude oil and natural gas on an equivalent basis. Realized prices are discussed below within Results of Operations.

Investing activities. For the three months ended March 31, 2013, net cash used in investing activities was $29.6 million as compared to $44.2 million for the same period in 2012. The $14.6 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.

Financing activities. For the three months ended March 31, 2013, net cash provided by financing activities was $17 million compared to cash used in financing activities of $0.0 million during the same period of 2012. The $17 million increase relates to draws on our Credit Facility.

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

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 March 31,			
	2013	2012	Change	% Change
Net production:				
Crude oil (MBbls)	206	241	(35)	(15)%*
Natural gas (MMcf)	738	904	(166)	(18)%*
Total production (MBoe)	328	392	(64)	(16)%
Average daily production (MBoe)	3.6	4.3	(0.7)	(16)%
Average realized sales price (a):				
Crude oil (Bbl)	$94.85	$106.84	$(11.99)	(11)%
Natural gas (Mcf)	$4.07	$3.92	$0.15	4%
Total on an equivalent basis (Boe)	$68.72	$74.73	$(6.01)	(8)%
Crude oil and natural gas revenues (in thousands):				
Crude oil revenue	$19,540	$25,749	$(6,209)	(24)%
Natural gas revenue	3,001	3,545	(544)	(15)%
Total	$22,541	$29,294	$(6,753)	(23)%
Additional per Boe data:				
Sales price	$68.72	$74.73	$(6.01)	(8)%
Lease operating expense	17.55	21.02	(3.47)	(17)%
Production taxes	1.64	1.40	0.24	17%
Operating margin	$49.53	$52.31	$(2.78)	(5)%
Other expenses per Boe:				
Depletion, depreciation and amortization	$33.66	$31.09	$2.57	8%
General and administrative	11.40	12.83	(1.43)	(11)%

(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 of crude oil	$94.37	$102.93	$(8.56)	(8)%
Basis differential and quality adjustments	1.12	4.78	(3.66)	(77)%
Transportation	(0.64)	(0.87)	0.23	(26)%
Average realized price per barrel of crude oil	$94.85	$106.84	$(11.99)	(11)%
Average NYMEX price per million British thermal units ("MMBtu")	$3.48	$2.51	$0.97	39%
Basis differential, quality and Btu adjustments	0.59	1.41	(0.82)	(58)%
Average realized price per Mcf of natural gas	$4.07	$3.92	$0.15	4%

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

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

Revenues

The following table is 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 March 31, 2011	$18,804	$6,645	$25,449
Volume increase (decrease)	$3,841	$(2,170)	$1,671
Price increase (decrease)	3,104	(930)	2,174
Impact of hedges	—	—	—
Net increase (decrease) in 2012	6,945	(3,100)	3,845
Revenues for the three-months ended March 31, 2012	$25,749	$3,545	$29,294
Volume decrease	$(3,739)	$(651)	$(4,390)
Price decrease (increase)	(2,470)	107	(2,363)
Impact of hedges	—	—	—
Net decrease in 2013	(6,209)	(544)	(6,753)
Revenues for the three-months ended March 31, 2013	$19,540	$3,001	$22,541

Crude oil revenue

Crude oil revenues decreased 24% to $19.5 million for the three months ended March 31, 2013 compared to revenues of $25.7 million for the same period of 2012. Contributing to the decrease in crude oil revenue was an 11% decrease in commodity prices compounded by a 15% decrease in production. The average price realized decreased to $94.85 per barrel compared to $106.84 for the same period of 2012. Production decreased to 206 thousand barrels (“MBbls”) during the first quarter of 2013 compared to production of 241 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 33 MBbls during the first quarter of 2012. Additionally, normal and expected declines further reduced oil production. Partially offsetting these decreases in our Gulf of Mexico and other properties was a 23 MBbls increase in production from newly producing wells on our Permian properties.

Natural gas revenue

Natural gas revenues of $3.0 million decreased 15% during the three months ended March 31, 2013 as compared to natural gas revenues of $3.5 million for the same period of 2012. The decline primarily relates to an 18% decrease in natural gas production, primarily attributable to the sale of our deepwater Habanero field in the fourth quarter of 2012, which produced 54 MMcf of natural gas during the first quarter of 2012 as well as other normal and expected declines in our Gulf of Mexico properties. These production decreases were partially offset by a 14 MMcf increase in natural gas production from our Haynesville well, which was shut-in for 70 days during the first quarter of 2012 due to well interference from an offsetting well, and to a 30 MMcf increase in the Permian. Also offsetting these production declines was a 4% increase in the average price realized, which rose to $4.07 per thousand cubic feet of natural gas ("Mcf") from $3.92 per Mcf.

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.

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

Operating Expenses

(in thousands except per unit data)	Three Months Ended March 31,							
					Total Change		Boe Change	
	2013	Per Boe	2012	Per Boe	$	%	$	%
Lease operating expenses	$5,758	$17.55	$8,237	$21.01	$(2,479)	(30)%	$(3.46)	(16)%
Production taxes	539	1.64	547	1.40	(8)	(1)%	0.24	17%
Depreciation, depletion and amortization	11,042	33.66	12,189	31.09	(1,147)	(9)%	2.57	8%
General and administrative	3,739	11.40	5,031	12.83	(1,292)	(26)%	(1.43)	(11)%
Accretion expense	565	1.72	574	1.46	(9)	(2)%	0.26	18%

Lease operating expenses (“LOE”)

Lease operating expenses for the three months ended March 31, 2013 decreased by 30% to $5.8 million compared to $8.2 million for the same period in 2012, which was primarily due to $2.9 million of workover costs in the prior year associated with our Haynesville well for which we had no similar costs in the current period. The additional LOE from our growing Permian operations was partially offset by a reduction in LOE associated with the sale of our Habanero deepwater property in December 2012.

Production taxes

Production taxes remained relatively flat for the three months ended March 31, 2013 as compared to the same period of 2012, though increased 17% on a per Boe basis. The increase relates to an increase of onshore production subject to these taxes while our offshore production is exempt from production taxes.

Depreciation, depletion and amortization

Depreciation, depletion and amortization (“DD&A”) for the three months ended March 31, 2013 and compared to the same period of 2012 decreased 9% to $11.0 million compared to $12.2 million. The overall decrease is primarily related to the 16% drop in total production in the first quarter of 2013 compared to the same quarter of 2012. The decrease in DD&A related to production was partially offset by an 8% increase in the DD&A rate on an equivalent basis. Partially contributing to the increase per Boe is that prior period DD&A rates were effectively reduced by the impact of a $486 million 2008 impairment charge following a ceiling test writedown, which resulted in a lower, prospective DD&A rate for the then existing reserves. Subsequent increases in the rate are attributable to our exploration and development expenditures related to our onshore reserve development including the ongoing onshore development cost increases in the Permian Basin area.

General and administrative

General and administrative expenses, net of amounts capitalized, decreased to $3.7 million for the three months ended March 31, 2013 from $5.0 million for the same period of 2012. The decrease primarily consists of a $0.9 million downward revision for the mark-to-market adjustment of certain liability-based incentive compensation instruments. We also recorded a $0.4 million reduction to our performance-based incentive compensation accrual during the first quarter of 2013.

Accretion expense

Accretion expense related to our asset retirement obligation decreased 2% for the three months ended March 31, 2013 compared to the same period of 2012. 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

Other Income and Expenses

(in thousands)	Three Months Ended March 31,			
	2013	2012	$ Change	% Change
Interest expense	$1,515	$2,577	$(1,062)	(41)%
Loss (gain) on derivative contracts	418	(70)	488	697%
Other (income) expense	(45)	(305)	260	(85)%
Income tax expense (benefit)	(169)	144	(313)	(217)%
Equity in earnings of Medusa Spar LLC	21	118	(97)	(82)%

Interest expense

Interest expense incurred during the three months ended March 31, 2013 decreased $1.1 million or 41% to $1.5 million compared to $2.6 million for the same period of 2012. The decrease in interest expense is primarily related to a $0.9 million increase in capitalized interest resulting from a $54.4 million higher average unevaluated property balance for the three months ended March 31, 2013 compared to the corresponding period of 2012. Also contributing to the decrease is $0.3 million lower interest expense related to our Senior Notes following a $10 million principal redemption during the second quarter of 2012, which was partially offset by an additional $0.1 million interest expense related to additional draws on our Credit Facility in 2013 compared to the corresponding period of the prior year.

Loss (gain) on derivative contracts

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

Income tax expense (benefit)

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

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% 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 March 31, 2013, we have commodity contracts covering approximately 50% and 35% of our internally forecasted proved developed producing crude oil and natural gas production, respectively, from April 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 March 31, 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 March 31, 2013, the majority of the Company's debt consisted of its fixed-rate 13% Senior Notes. However, the Company's Credit Facility with Regions Bank includes a variable interest rate, and as such fluctuates based on short-term interest rates. Although the Company had $27 million borrowings outstanding at March 31, 2013 under its Credit Facility, were the Company to fully draw its available $65 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 March 31, 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 March 31, 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.

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.

Item 6. Exhibits

Index of 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)
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)
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.

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	May 9, 2013
/s/ B.F. Weatherly B.F. Weatherly	Executive Vice President and Chief Financial Officer	May 9, 2013