CALLON PETROLEUM CO
Form 10-Q
August 02, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For The Quarterly Period Ended June 30, 2017
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<br>(State or Other Jurisdiction of Incorporation or Organization) | 64-0844345<br>(IRS Employer Identification No.) |
| 200 North Canal Street<br>Natchez, Mississippi<br>(Address of Principal Executive Offices) | 39120<br>(Zip Code) |

601-442-1601
(Registrant's Telephone Number, Including Area Code)

Not Applicable
(Former Name, Former Address and Former Fiscal Year, If Changed Since Last Report)

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

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

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

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

| | |
|---|---|
| Smaller reporting company | Emerging growth company |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

The Registrant had 201,827,995 shares of common stock outstanding as of July 28, 2017.

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DEFINITIONS

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

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

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

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

| | June 30, 2017 Unaudited | December 31, 2016 |
|---|---|---|
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $139,149 | $652,993 |
| Accounts receivable | 77,635 | 69,783 |
| Fair value of derivatives | 9,241 | 103 |
| Other current assets | 2,545 | 2,247 |
| Total current assets | 228,570 | 725,126 |
| Oil and natural gas properties, full cost accounting method: | | |
| Evaluated properties | 3,125,238 | 2,754,353 |
| Less accumulated depreciation, depletion, amortization and impairment | (1,998,294 ) | (1,947,673 ) |
| Net evaluated oil and natural gas properties | 1,126,944 | 806,680 |
| Unevaluated properties | 1,194,999 | 668,721 |
| Total oil and natural gas properties | 2,321,943 | 1,475,401 |
| Other property and equipment, net | 18,071 | 14,114 |
| Restricted investments | 3,348 | 3,332 |
| Deferred financing costs | 5,273 | 3,092 |
| Fair value of derivatives | 3,804 | — |
| Acquisition deposit | — | 46,138 |
| Other assets, net | 655 | 384 |
| Total assets | $2,581,664 | $2,267,587 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $144,958 | $95,577 |
| Accrued interest | 9,256 | 6,057 |
| Cash-settleable restricted stock unit awards | 3,650 | 8,919 |
| Asset retirement obligations | 1,767 | 2,729 |
| Fair value of derivatives | 2,243 | 18,268 |
| Total current liabilities | 161,874 | 131,550 |
| Senior secured revolving credit facility | — | — |
| 6.125% senior unsecured notes due 2024, net of unamortized deferred financing costs | 595,138 | 390,219 |
| Asset retirement obligations | 5,031 | 3,932 |
| Cash-settleable restricted stock unit awards | 1,957 | 8,071 |
| Deferred tax liability | 921 | 90 |
| Fair value of derivatives | 441 | 28 |
| Other long-term liabilities | 405 | 295 |
| Total liabilities | 765,767 | 534,185 |
| Commitments and contingencies | | |
| Stockholders' equity: | | |
| Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized; 1,458,948 and 1,458,948 shares outstanding, respectively | 15 | 15 |
| Common stock, $0.01 par value, 300,000,000 and 300,000,000 shares authorized; 201,806,900 and 201,041,320 shares outstanding, respectively | 2,018 | 2,010 |

| | | |
|---|---|---|
| Capital in excess of par value | 2,177,547 | 2,171,514 |
| Accumulated deficit | (363,683 ) | (440,137 ) |
| Total stockholders' equity | 1,815,897 | 1,733,402 |
| Total liabilities and stockholders' equity | $2,581,664 | $2,267,587 |

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, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Operating revenues: | | | | |
| Oil sales | $72,885 | $40,555 | $144,893 | $67,998 |
| Natural gas sales | 9,398 | 4,590 | 18,754 | 7,845 |
| Total operating revenues | 82,283 | 45,145 | 163,647 | 75,843 |
| Operating expenses: | | | | |
| Lease operating expenses | 12,145 | 7,311 | 25,084 | 14,268 |
| Production taxes | 4,820 | 2,455 | 10,723 | 4,675 |
| Depreciation, depletion and amortization | 26,213 | 16,293 | 50,646 | 32,015 |
| General and administrative | 6,430 | 6,302 | 11,636 | 11,864 |
| Settled share-based awards | 6,351 | — | 6,351 | — |
| Accretion expense | 208 | 395 | 392 | 575 |
| Write-down of oil and natural gas properties | — | 61,012 | — | 95,788 |
| Acquisition expense | 2,373 | 1,906 | 2,822 | 1,954 |
| Total operating expenses | 58,540 | 95,674 | 107,654 | 161,139 |
| Income (loss) from operations | 23,743 | (50,529) | 55,993 | (85,296) |
| Other (income) expenses: | | | | |
| Interest expense, net of capitalized amounts | 589 | 4,180 | 1,254 | 9,671 |
| (Gain) loss on derivative contracts | (10,494) | 15,484 | (25,797) | 16,416 |
| Other income | (64) | (96) | (772) | (177) |
| Total other (income) expense | (9,969) | 19,568 | (25,315) | 25,910 |
| Income (loss) before income taxes | 33,712 | (70,097) | 81,308 | (111,206) |
| Income tax expense | 322 | — | 789 | — |
| Net income (loss) | 33,390 | (70,097) | 80,519 | (111,206) |
| Preferred stock dividends | (1,824) | (1,823) | (3,647) | (3,647) |
| Income (loss) available to common stockholders | $31,566 | $(71,920) | $76,872 | $(114,853) |
| Income (loss) per common share: | | | | |
| Basic | $0.16 | $(0.61) | $0.38 | $(1.14) |
| Diluted | $0.16 | $(0.61) | $0.38 | $(1.14) |
| Shares used in computing income (loss) per common share: | | | | |
| Basic | 201,386 | 118,209 | 201,220 | 100,895 |
| Diluted | 201,905 | 118,209 | 201,823 | 100,895 |

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, 2017 | 2016 |
|---|---|---|
| Cash flows from operating activities: | | |
| Net income (loss) | $80,519 | $(111,206) |
| Adjustments to reconcile net income to cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 51,697 | 32,827 |
| Write-down of oil and natural gas properties | — | 95,788 |
| Accretion expense | 392 | 575 |
| Amortization of non-cash debt related items | 1,254 | 1,561 |
| Deferred income tax expense | 789 | — |
| Net (gain) loss on derivatives, net of settlements | (28,555) | 28,149 |
| Loss on sale of other property and equipment | 62 | — |
| Non-cash expense related to equity share-based awards | 5,795 | 1,177 |
| Change in the fair value of liability share-based awards | 1,691 | 2,674 |
| Payments to settle asset retirement obligations | (1,581) | (319) |
| Changes in current assets and liabilities: | | |
| Accounts receivable | (7,810) | (4,836) |
| Other current assets | (298) | (305) |
| Current liabilities | 5,680 | 4,113 |
| Change in other long-term liabilities | 120 | 86 |
| Change in other assets, net | (770) | (450) |
| Payments to settle vested liability share-based awards | (13,173) | (10,300) |
| Net cash provided by operating activities | 95,812 | 39,534 |
| Cash flows from investing activities: | | |
| Capital expenditures | (146,090) | (75,280) |
| Acquisitions | (706,489) | (284,024) |
| Acquisition deposit | 46,138 | — |
| Proceeds from sales of mineral interests and equipment | — | 23,631 |
| Net cash used in investing activities | (806,441) | (335,673) |
| Cash flows from financing activities: | | |
| Borrowings on senior secured revolving credit facility | — | 143,000 |
| Payments on senior secured revolving credit facility | — | (143,000) |
| Issuance of 6.125% senior unsecured notes due 2024 | 200,000 | — |
| Premium on the issuance of 6.125% senior unsecured notes due 2024 | 8,250 | — |
| Issuance of common stock | — | 300,807 |
| Payment of preferred stock dividends | (3,647) | (3,647) |
| Payment of deferred financing costs | (6,765) | — |
| Tax withholdings related to restricted stock units | (1,053) | (2,038) |
| Net cash provided by financing activities | 196,785 | 295,122 |
| Net change in cash and cash equivalents | (513,844) | (1,017) |
| Balance, beginning of period | 652,993 | 1,224 |
| Balance, end of period | $139,149 | $207 |

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

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Note 1 - Description of Business and Basis of Presentation

Description of business

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

Callon is focused on the acquisition, development, exploration and exploitation of unconventional onshore, oil and natural gas reserves in the Permian Basin in West Texas. The Company's operations to date have been predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shales. Callon has assembled a multi-year inventory of potential horizontal well locations and intends to add to this inventory through delineation drilling of emerging zones on its existing acreage and acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps.

Basis of presentation

Unless otherwise indicated, all dollar amounts included within the Footnotes to the Financial Statements are presented in thousands, except for per share and per unit data.

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

These interim consolidated financial statements should be read in conjunction with the Company's Annual Report on Form 10-K for the year ended December 31, 2016. The balance sheet at December 31, 2016 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, 2017.

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

Recently issued accounting policies

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will replace most of the existing revenue recognition requirements in GAAP when it becomes effective. In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU 2014-09 by one year. As a result, the standard is effective for annual periods beginning on or after December 31, 2017, including interim periods within that reporting period. The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoption. The Company is still evaluating the impact of the standard but has performed a preliminary assessment of the impact and developed an implementation plan to adopt the new standard. To date, the Company has not identified any material impact that the new standard will have on the Company's Consolidated Financial Statements. The Company intends to adopt the new standard on January 1, 2018 using the modified retrospective method at the date of adoption.

(All dollar amounts in thousands, except per share and per unit data) Table of Contents

Recently adopted accounting policies

In March 2016, the FASB issued ASU No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). The standard is intended to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows, and will allow companies to estimate the number of stock awards expected to vest. The guidance in ASU 2016-09 is effective for public entities for annual reporting periods beginning after December 15, 2016, including interim periods therein. The Company adopted this ASU on January 1, 2017 and it did not have a material impact on its financial statements. The Company has elected to no longer estimate forfeitures.

Note 2 - Acquisitions

Acquisitions were accounted for under the acquisition method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed under the income approach.

2017 acquisitions

On February 13, 2017, the Company completed the acquisition of 29,175 gross (16,688 net) acres in the Delaware Basin, primarily located in Ward and Pecos Counties, Texas from American Resource Development, LLC, for total cash consideration of $632,947, excluding customary purchase price adjustments (the "Ameredev Transaction"). The Company funded the cash purchase price with the net proceeds of an equity offering (see Note 9 for additional information regarding the equity offering). The Company acquired an 82% average working interest in the properties acquired in the Ameredev Transaction. In December 2016, in connection with the execution of the purchase and sale agreement for the Ameredev Transaction, the Company paid a deposit in the amount of $46,138 to a third party escrow agent, which was recorded as Acquisition deposit on the balance sheet as of December 31, 2016. The following table summarizes the estimated acquisition date fair values of the acquisition:

| | |
|---|---|
| Evaluated oil and natural gas properties | $134,315 |
| Unevaluated oil and natural gas properties | 498,800 |
| Asset retirement obligations | (168) |
| Net assets acquired | $632,947 |

The preliminary purchase price allocation is subject to change based on numerous factors, including the final adjusted purchase price and the final estimated fair value of the assets acquired and liabilities assumed. Any such adjustments to the preliminary estimates of fair value could be material.

On June 5, 2017, the Company completed the acquisition of 7,031 gross (2,488 net) acres in the Delaware Basin, located near the acreage acquired in the Ameredev Transaction discussed above, for total cash consideration of $52,500, excluding customary purchase price adjustments. The Company funded the cash purchase price with its available cash and proceeds from the issuance of an additional $200,000 of its 6.125% senior notes due 2024 (see Note 4 for additional information regarding the Company's debt obligations).

2016 acquisitions

On October 20, 2016, the Company completed the acquisition of 6,904 gross (5,952 net) acres in the Midland Basin, primarily located in Howard County, Texas from Plymouth Petroleum, LLC and additional sellers that exercised their "tag-along" sales rights, for total cash consideration of $339,687, excluding customary purchase price adjustments (the "Plymouth Transaction"). The Company funded the cash purchase price with the net proceeds of an equity offering (see Note 9 for additional information regarding the equity offering). The Company acquired an 82% average working interest (62% average net revenue interest) in the properties acquired in the Plymouth Transaction.

On May 26, 2016, the Company completed the acquisition of 17,298 gross (14,089 net) acres in the Midland Basin, primarily located in Howard County, Texas from BSM Energy LP, Crux Energy LP and Zaniah Energy LP, for total cash consideration of $220,000 and 9,333.333 shares of common stock (at an assumed offering price of $11.74 per share, which is the last reported sale price of our common stock on the New York Stock Exchange on that date) for a total purchase price of $329,573, excluding customary purchase price adjustments (the “Big Star Transaction”). The Company acquired an 81% average working interest (61% average net revenue interest) in the properties acquired in the Big Star Transaction.

Unaudited pro forma financial statements

The following unaudited summary pro forma financial information for the periods presented is for illustrative purposes only and does not purport to represent what the Company's results of operations would have been if the Ameredev Transaction, Plymouth Transaction and Big Star Transaction had occurred as presented, or to project the Company's results of operations for any future periods:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 [a] | 2016 [a] | 2017 [a] | 2016 [a] |
| Revenues | $82,283 | $48,534 | $166,699 | $91,149 |
| Income (loss) from operations | 23,743 | (57,037) | 58,650 | (92,488) |
| Income (loss) available to common stockholders | 31,566 | (73,207) | 79,529 | (112,115) |
| | | | | |
| Net income (loss) per common share: | | | | |
| Basic | $0.16 | $(0.46) | $0.40 | $(0.80) |
| Diluted | $0.16 | $(0.46) | $0.40 | $(0.80) |

(a) The pro forma financial information was prepared assuming the Ameredev Transaction occurred as of January 1, 2016 and the Plymouth Transaction and Big Star Transaction occurred as of January 1, 2015.

The pro forma adjustments are based on available information and certain assumptions that management believes are reasonable, including revenue, lease operating expenses, production taxes, depreciation, depletion and amortization expense, accretion expense, interest expense and capitalized interest.

The properties associated with the Ameredev Transaction, Plymouth Transaction and Big Star Transaction have been commingled with our existing properties and it is impractical to provide the stand-alone operational results related to these properties.

Note 3 - Earnings Per Share

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

| (share amounts in thousands) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Net income (loss) | $33,390 | $(70,097) | $80,519 | $(111,206) |
| Preferred stock dividends | (1,824) | (1,823) | (3,647) | (3,647) |
| Income (loss) available to common stockholders | $31,566 | $(71,920) | $76,872 | $(114,853) |
| | | | | |
| Weighted average shares outstanding | 201,386 | 118,209 | 201,220 | 100,895 |
| Dilutive impact of restricted stock | 519 | — | 603 | — |
| Weighted average shares outstanding for diluted income (loss) per share | 201,905 | 118,209 | 201,823 | 100,895 |
| | | | | |
| Basic income (loss) per share | $0.16 | $(0.61) | $0.38 | $(1.14) |
| Diluted income (loss) per share | $0.16 | $(0.61) | $0.38 | $(1.14) |
| | | | | |
| Stock options [a] | — | 15 | — | 15 |
| Restricted stock [a] | 22 | 36 | 22 | 36 |

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

(All dollar amounts in thousands, except per share and per unit data) Table of Contents

Note 4 - Borrowings

The Company's borrowings consisted of the following at:

| | June 30, 2017 | December 31, 2016 |
|---|---|---|
| Principal components: | | |
| Senior secured revolving credit facility | $— | $ — |
| 6.125% senior unsecured notes due 2024 | 600,000 | 400,000 |
| Total principal outstanding | 600,000 | 400,000 |
| Premium on 6.125% senior unsecured notes due 2024, net of accumulated amortization | 8,156 | — |
| Unamortized deferred financing costs | (13,018 ) | (9,781 ) |
| Total carrying value of borrowings | $595,138 | $ 390,219 |

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

On May 31, 2017, the Company entered into the Sixth Amended and Restated Credit Agreement to the Credit Facility with a maturity date of May 25, 2022. JPMorgan Chase Bank, N.A. is Administrative Agent, and participants include 17 institutional lenders. The total notional amount available under the Credit Facility is $2,000,000. Amounts borrowed under the Credit Facility may not exceed the borrowing base, which is generally reviewed on a semi-annual basis. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. Concurrent with the execution of the Sixth Amended and Restated Credit Agreement, the Credit Facility's borrowing base increased to $650,000, but the Company elected an aggregate commitment amount of $500,000. As of June 30, 2017, the Company continued to maintain the Credit Facility's borrowing base at $500,000.

As of June 30, 2017, there was no balance outstanding on the Credit Facility. For the quarter ended June 30, 2017, the Credit Facility had a weighted-average interest rate of 3.08%, calculated as the LIBOR plus a tiered rate ranging from 2.00% to 3.00%, which is determined based on utilization of the facility. In addition, the Credit Facility carries a commitment fee of 0.375% per annum, payable quarterly, on the unused portion of the borrowing base.

6.125% senior notes due 2024 ("6.125% Senior Notes")

On October 3, 2016, the Company issued $400,000 aggregate principal amount of 6.125% Senior Notes with a maturity date of October 1, 2024 and interest payable semi-annually beginning on April 1, 2017. The net proceeds of the offering, after deducting initial purchasers' discounts and estimated offering expenses, were approximately $391,270. The 6.125% Senior Notes are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 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 guarantor are minor.

On May 19, 2017, the Company issued an additional $200,000 aggregate principal amount of its 6.125% Senior Notes which with the existing $400,000 aggregate principal amount of 6.125% Senior Notes are treated as a single class of notes under the indenture. The net proceeds of the offering, including a premium issue price of 104.125% and after deducting initial purchasers' discounts and estimated offering expenses, were approximately $206,139. The Company used the proceeds, in part, to fund an acquisition completed on June 5, 2017 (discussed further in Note 2) and for general corporate purposes.

The Company may redeem the 6.125% Senior Notes in accordance with the following terms; (1) prior to October 1, 2019, a redemption of up to 35% of the principal in an amount not greater than the net proceeds from certain equity offerings, and within 180 days of the closing date of such equity offerings, at a redemption price of 106.125% of principal, plus accrued and unpaid interest, if any, to the date of the redemption, if at least 65% of the principal will remain outstanding after such redemption; (2) prior to October 1, 2019, a redemption of all or part of the principal at a price of 100% of principal of the amount redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of the redemption; (3) a redemption, in whole or in part, at a redemption price, plus accrued and unpaid interest, if any, to the date of the redemption, (i) of 104.594% of principal if the redemption occurs on or after October 1, 2019, but before October 1, 2020, and (ii) of 103.063% of principal if the redemption occurs on or after October 1, 2020, but before October 1, 2021, and (iii) of 101.531% of principal if the redemption occurs on or after October 1, 2021, but before October 1, 2022, and (iv) of 100% of principal if the redemption occurs on or after October 1, 2022.

Following a change of control, each holder of the 6.125% Senior Notes may require the Company to repurchase all or a portion of the 6.125% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest, if any, to the date of repurchase.

Restrictive covenants

The Company's Credit Facility and the indenture governing our 6.125% Senior Notes contain various covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. The Company was in compliance with these covenants at June 30, 2017.

Note 5 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

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

Counterparty risk and offsetting

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

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

Financial statement presentation and settlements

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

Derivatives not designated as hedging instruments

The Company records its derivative contracts at fair value in the consolidated balance sheets and records changes in fair value as a gain or loss on derivative contracts in the consolidated statements of operations. Cash settlements are also recorded as gain or loss on derivative contracts in the consolidated statements of operations.

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

| | Balance Sheet Presentation | | Asset Fair Value | | Liability Fair Value | | Net Derivative Fair Value | |
|---|---|---|---|---|---|---|---|---|
| Commodity | Classification | Line Description | 6/30/2017 | 12/31/2016 | 6/30/2017 | 12/31/2016 | 6/30/2017 | 12/31/2016 |
| Natural gas | Current | Fair value of derivatives | $567 | $ — | $— | $(593) | $567 | $(593) |
| Oil | Current | Fair value of derivatives | 8,674 | 103 | (2,243) | (17,675) | 6,431 | (17,572) |
| Oil | Non-current | Fair value of derivatives | 3,804 | — | (441) | (28) | 3,363 | (28) |
| | Totals | | $13,045 | $ 103 | $(2,684) | $(18,296) | $10,361 | $(18,193) |

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

Callon Petroleum Company Notes to the Consolidated Financial Statements (All dollar amounts in thousands, except per share and per unit data) Table of Contents

| | June 30, 2017 | | |
|---|---|---|---|
| | Presented without Effects of Netting | Effects of Netting | As Presented with Effects of Netting |
| Current assets: Fair value of derivatives | $11,104 | $(1,863) | $9,241 |
| Long-term assets: Fair value of derivatives | 3,813 | (9) | 3,804 |
| | | | |
| Current liabilities: Fair value of derivatives | $(4,106) | $1,863 | $(2,243) |
| Long-term liabilities: Fair value of derivatives | (450) | 9 | (441) |

| | December 31, 2016 | | |
|---|---|---|---|
| | Presented without Effects of Netting | Effects of Netting | As Presented with Effects of Netting |
| Current assets: Fair value of derivatives | $1,836 | $(1,733) | $103 |
| | | | |
| Current liabilities: Fair value of derivatives | $(20,001) | $1,733 | $(18,268) |
| Long-term liabilities: Fair value of derivatives | (28) | — | (28) |

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Oil derivatives | | | | |
| Net gain (loss) on settlements | $(315) | $3,707 | $(2,840) | $11,214 |
| Net gain (loss) on fair value adjustments | 10,128 | (18,466) | 27,394 | (27,604) |
| Total gain (loss) on oil derivatives | $9,813 | $(14,759) | $24,554 | $(16,390) |
| Natural gas derivatives | | | | |
| Net gain on settlements | $48 | $310 | $82 | $519 |
| Net gain (loss) on fair value adjustments | 633 | (1,035) | 1,161 | (545) |
| Total gain (loss) on natural gas derivatives | $681 | $(725) | $1,243 | $(26) |
| | | | | |
| Total gain (loss) on oil & natural gas derivatives | $10,494 | $(15,484) | $25,797 | $(16,416) |

(All dollar amounts in thousands, except per share and per unit data) Table of Contents

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of June 30, 2017:

| Oil contracts (WTI) | For the Remainder of 2017 | For the Full Year of 2018 |
|---|---|---|
| Swap contracts combined with short puts (enhanced swaps) | | |
| Total volume (MBbls) | 368 | — |
| Weighted average price per Bbl | | |
| Swap | $ 44.50 | $— |
| Short put option | $ 30.00 | $— |
| Swap contracts | | |
| Total volume (MBbls) | 368 | — |
| Weighted average price per Bbl | $ 45.74 | $— |
| Deferred premium put spread option | | |
| Total volume (MBbls) | 506 | — |
| Premium per Bbl | $ 2.45 | $— |
| Weighted average price per Bbl | | |
| Long put option | $ 50.00 | $— |
| Short put option | $ 40.00 | $— |
| Collar contracts (two-way collars) | | |
| Total volume (MBbls) | 681 | — |
| Weighted average price per Bbl | | |
| Ceiling (short call) | $ 58.19 | $— |
| Floor (long put) | $ 47.50 | $— |
| Call option contracts | | |
| Total volume (MBbls) | 338 | — |
| Premium per Bbl | $ 1.82 | $— |
| Weighted average price per Bbl | | |
| Short call strike price [a] | $ 50.00 | $— |
| Long call strike price [a] | $ 50.00 | $— |
| Collar contracts combined with short puts (three-way collars) | | |
| Total volume (MBbls) | — | 3,468 |
| Weighted average price per Bbl | | |
| Ceiling (short call option) | $ — | $60.86 |
| Floor (long put option) | $ — | $48.95 |
| Short put option | $ — | $39.21 |

(a) Offsetting contracts.

| Oil contracts (Midland basis differential) | For the Remainder of 2017 | For the Full Year of 2018 |
|---|---|---|
| Swap contracts | | |

| | | |
|---|---|---|
| Volume (MBbls) | 1,104 | 2,190 |
| Weighted average price per Bbl | $ (0.52 ) | $(1.02) |

(All dollar amounts in thousands, except per share and per unit data) Table of Contents

| Natural gas contracts | For the Remainder of 2017 | For the Full Year of 2018 |
|---|---|---|
| Collar contracts combined with short puts (Henry Hub, three-way collars) | | |
| Total volume (BBtu) | 736 | — |
| Weighted average price per MMBtu | | |
| Ceiling (short call option) | $ 3.71 | $— |
| Floor (long put option) | $ 3.00 | $— |
| Short put option | $ 2.50 | $— |
| Collar contracts (Henry Hub, two-way collars) | | |
| Total volume (BBtu) | 1,224 | 720 |
| Weighted average price per MMBtu | | |
| Ceiling (short call option) | $ 3.74 | $3.84 |
| Floor (long put option) | $ 3.16 | $3.40 |
| Swap contracts | | |
| Total volume (BBtu) | 492 | — |
| Weighted average price per MMBtu | $ 3.39 | $— |

Subsequent event

The following derivative contracts were executed subsequent to June 30, 2017:

| Oil contracts (Midland basis differential) | For the Remainder of 2017 | For the Full Year of 2018 |
|---|---|---|
| Swap contracts | | |
| Volume (MBbls) | — | 548 |
| Weighted average price per Bbl | $ — | $(1.05 ) |

| Oil contracts (WTI) | For the Remainder of 2017 | For the Full Year of 2018 |
|---|---|---|
| Swap contracts | | |
| Volume (MBbls) | — | 730 |
| Weighted average price per Bbl | $ — | $50.03 |

Note 6 - Fair Value Measurements

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

Fair value of financial instruments

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

Debt. The carrying amount of the Company's floating-rate debt approximated fair value because the interest rates were variable and reflective of market rates.

| | June 30, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Credit Facility [(a)] | $— | $— | $— | $— |
| 6.125% Senior Notes [(b)] | 595,138 | 610,500 | 390,219 | 412,000 |
| Total | $595,138 | $610,500 | $390,219 | $412,000 |

(a) Floating-rate debt.

(b) The fair value was based upon Level 2 inputs. See Note 4 for additional information about the Company's 6.125% Senior Notes.

Assets and liabilities measured at fair value on a recurring basis

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

(All dollar amounts in thousands, except per share and per unit data) Table of Contents

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

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

| June 30, 2017 | Classification | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| Assets | | | | | |
| Derivative financial instruments | Fair value of derivatives | $ — | $13,045 | $ — | $13,045 |
| Liabilities | | | | | |
| Derivative financial instruments | Fair value of derivatives | — | (2,684) | — | (2,684) |
| Total net liabilities | | $ — | $10,361 | $ — | $10,361 |

| December 31, 2016 | Classification | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| Assets | | | | | |
| Derivative financial instruments | Fair value of derivatives | $ — | $103 | $ — | $103 |
| Liabilities | | | | | |
| Derivative financial instruments | Fair value of derivatives | — | (18,296) | — | (18,296) |
| Total net liabilities | | $ — | $(18,193) | $ — | $(18,193) |

Assets and liabilities measured at fair value on a nonrecurring basis

Acquisitions. The Company determines the fair value of the assets acquired and liabilities assumed using the income approach based on expected discounted future cash flows from estimated reserve quantities, costs to produce and develop reserves, and oil and natural gas forward prices. The future net revenues are discounted using a weighted average cost of capital. The discounted future net revenues of proved undeveloped and probable reserves are reduced by an additional reserve adjustment factor to compensate for the inherent risk of estimating the value of unevaluated properties. The fair value measurements were based on Level 2 and Level 3 inputs.

Note 7 - Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, which primarily relate to non-deductible executive compensation expenses and state income taxes. As a result of the write-down of oil and natural gas properties in the latter part of 2015 and the first half of 2016, the Company has incurred a cumulative three years loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the ability to realize its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a full valuation allowance for all of the deferred tax asset. The valuation allowance was $115,879 as of June 30, 2017.

The Company recently adopted a new accounting standard that simplified the accounting for stock-based compensation. As a result, the Company recorded a cumulative-effect adjustment to retained earnings as of January 1, 2017 for all windfall tax benefits that were not previously recognized because the related tax deduction had not reduced current taxes payable. Due to the Company's valuation allowance position, a cumulative-effect adjustment was recorded to retained earnings as of January 1, 2017, and therefore, the net effect of this new accounting standard was zero. See Note 1 for additional information about this new accounting standard.

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Note 8 - Asset Retirement Obligations

The table below summarizes the activity for the Company's asset retirement obligations:

| | For The Six Months Ended June 30, 2017 |
|---|---|
| Asset retirement obligations at January 1, 2017 | $6,661 |
| Accretion expense | 392 |
| Liabilities incurred | 208 |
| Liabilities settled | (227) |
| Revisions to estimate | (236) |
| Asset retirement obligations at end of period | 6,798 |
| Less: Current asset retirement obligations | (1,767) |
| Long-term asset retirement obligations at June 30, 2017 | $5,031 |

Certain of the Company's operating agreements require that assets be restricted for abandonment obligations. Amounts recorded in the Consolidated Balance Sheets at June 30, 2017 as long-term restricted investments were $3,348. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 9 - Equity Transactions

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

Holders of the Company's Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10.0% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends are payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by our Board of Directors. Preferred Stock dividends were $1,824 and $1,823 for the three months ended June 30, 2017 and 2016, respectively, and $3,647 and $3,647 for the six months ended June 30, 2017 and 2016, respectively.

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

Following a change of control in which the Company or the acquirer no longer have a class of common securities listed on a national exchange, the Company will have the option to redeem the Preferred Stock, in whole but not in part for $50.00 per share in cash, plus accrued and unpaid dividends (whether or not declared), to the redemption date. If the Company does not exercise its option to redeem the Preferred Stock upon such change of control, the holders of the Preferred Stock have the option to convert the Preferred Stock into a number of shares of the Company's common stock based on the value of the common stock on the date of the change of control as determined under the certificate of designations for the Preferred Stock. If the change of control occurred on June 30, 2017, and the Company did not exercise its right to redeem the Preferred Stock, using the closing price of $10.61 as the value of a share of common stock, each share of Preferred Stock would be convertible into approximately 4.7 shares of common stock. If the

Company exercises its redemption rights relating to shares of Preferred Stock, the holders of Preferred Stock will not have the conversion right described above.

On February 4, 2016, the Company exchanged a total of 120,000 shares of Preferred Stock for 719,000 shares of common stock. As of June 30, 2017, the Company had 1,458,948 shares of its Preferred Stock issued and outstanding.

Common stock

On December 19, 2016, the Company completed an underwritten public offering of 40,000,000 shares of its common stock for total estimated net proceeds (after the underwriter's discounts and estimated offering expenses) of approximately $634,917. Proceeds from the offering were used to substantially fund the Ameredev Transaction, described in Note 2.

On September 6, 2016, the Company completed an underwritten public offering of 29,900,000 shares of its common stock for total estimated net proceeds (after the underwriter's discounts and estimated offering expenses) of approximately $421,864. Proceeds from the offering were used to substantially fund the Plymouth Transaction, described in Note 2.

On May 26, 2016, the Company issued 9,333,333 shares of common stock to partially fund the Big Star Transaction, described in Note 2, at an assumed offering price of $11.74 per share, which is the last reported sale price of our common stock on the New York Stock Exchange on that date.

On April 25, 2016, the Company completed an underwritten public offering of 25,300,000 shares of its common stock for total net proceeds (after the underwriter's discounts and commissions and estimated offering expenses) of approximately $205,869. Proceeds from the offering were used to fund the Big Star Transaction, described in Note 2, and other working interest acquisitions.

On March 9, 2016, the Company completed an underwritten public offering of 15,250,000 shares of its common stock for total net proceeds (after the underwriting discounts and estimated offering costs) of approximately $94,948. Proceeds from the offering were used to pay down the balance on the Company's Credit Facility and for general corporate purposes.

Note 10 - Other

Operating leases

As of June 30, 2017 the Company had contracts for four horizontal drilling rigs (the "Cactus 1 Rig", "Cactus 2 Rig", "Cactus 3 Rig", and "Independence Rig"). The contract terms, as amended in July 2017, of the Cactus 1 Rig and Cactus 2 Rig will end in January 2020 and February 2021, respectively. The contract terms, as amended in July 2017, of the Cactus 3 Rig that commenced drilling in mid-January 2017, will end in July 2018. Effective April 2017, the Company entered into a contract for the Independence Rig, which commenced drilling in July 2017. The contract terms of the Independence Rig will end in July 2019. The rig lease agreements include early termination provisions that obligate the Company to pay reduced minimum rentals for the remaining term of the agreement. These payments would be reduced assuming the lessor is able to re-charter the rig and staffing personnel to another lessee.

Special Note Regarding Forward Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may 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 some cases, you can identify forward-looking statements in this Form 10-Q by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "pro "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- our oil and gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future production and operating costs;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to efficiently integrate recently completed acquisitions; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements, include:

- general economic conditions including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of endangered species;
- any increase in severance or similar taxes;
- litigation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- weather conditions; and
- any other factors listed in the reports we have filed and may file with the SEC.

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016 (the "2016 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described herein or in our 2016 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 2016 Annual Report on Form 10-K, which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this report on Form 10-Q.

We are an independent oil and natural gas company established in 1950. We are focused on the acquisition, development, exploration and exploitation of unconventional, onshore, oil and natural gas reserves in the Permian Basin in West Texas. The Permian Basin is located in West Texas and southeastern New Mexico and is comprised of three primary sub-basins: the Midland Basin, the Delaware Basin, and the Central Basin Platform. We have historically been focused on the Midland Basin and recently entered the Delaware Basin through an acquisition completed in February 2017. Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals, including multiple levels of the Wolfcamp formation and, more recently, the Lower Spraberry shales. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps. Our production was approximately 79% oil and 21% natural gas for the six months ended June 30, 2017. On June 30, 2017, our net acreage position in the Permian Basin was approximately 58,208 net acres. See Note 2 in the Footnotes to the Financial Statements for additional information about the Company's acquisitions.

Operational Highlights

All of our producing properties are located in the Permian Basin. As a result of our acquisition and horizontal development efforts, our production grew 65% and 64% for the three and six months ended June 30, 2017, respectively, compared to the same periods of 2016. Production increased to 2,021 MBOE for the three months ended June 30, 2017 from 1,224 MBOE for the three months ended June 30, 2016 and increased to 3,860 MBOE for the six months ended June 30, 2017 from 2,357 MBOE for the six months ended June 30, 2016.

For the three months ended June 30, 2017, we drilled 14 gross (10.7 net) horizontal wells and completed 12 gross (9.6 net) horizontal wells. For the six months ended June 30, 2017 we drilled 23 gross (18.6 net) horizontal wells and completed 19 gross (14.5 net) horizontal wells. As of June 30, 2017, we had 10 gross (8.2 net) horizontal wells awaiting completion.

As of June 30, 2017, we had 522 gross (408 net) working interest oil wells, three gross (0.1 net) royalty interest oil wells and no natural gas wells. A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a BOE basis. However, most of our wells produce both oil and natural gas.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions, the sale of debt and equity securities, and asset dispositions. Our primary uses of capital have been for the acquisition, development, exploration and exploitation of oil and natural gas properties, in addition to refinancing of debt instruments. We continue to evaluate other sources of capital to complement our cash flows from operations as we pursue our long-term growth plans. As of June 30, 2017, there was no balance outstanding on the Credit Facility, which has a borrowing base of $650 million with a current elected commitment of $500 million. For the six months ended June 30, 2017, cash and cash equivalents increased $138.9 million to $139.1 million compared to $0.2 million at June 30, 2016.

Liquidity and cash flow

| | Six Months Ended June 30, | |
|---|---|---|
| (in millions) | 2017 | 2016 |
| Net cash provided by operating activities | $95.8 | $39.5 |
| Net cash used in investing activities | (806.4 ) | (335.7) |
| Net cash provided by financing activities | 196.8 | 295.2 |
| Net change in cash and cash equivalents | $(513.8) | $(1.0 ) |

Operating activities. For the six months ended June 30, 2017, net cash provided by operating activities was $95.8 million compared to net cash provided by operating activities of $39.5 million for the same period in 2016. The change was predominantly attributable to the following:

- An increase in revenue offset by a decrease on settlements of derivative contracts;
- An increase in certain operating expenses related to acquired properties;
- An increase in payments in cash-setttled restricted stock unit ("RSU") awards; and
- A change related to the timing of working capital payments and receipts.

Production, realized prices, and operating expenses are discussed below in Results of Operations. See Notes 4, 5 and 6 in the Footnotes to the Financial Statements for additional information on our debt and a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. For the six months ended June 30, 2017, net cash used in investing activities was $806.4 million compared to $335.7 million for the same period in 2016. The change was predominantly attributable to the following:

- A $56.4 million increase in operational expenditures due to the transition from a two-rig to a three-rig program in January 2017; and
- A $376.3 million increase in acquisition activity. See Note 2 in the Footnotes to the Financial Statements for additional information on the Company's acquisitions.

Our investing activities, on a cash basis, include the following for the periods indicated (in millions):

| | Six Months Ended June 30, | | |
|---|---|---|---|
| | 2017 | 2016 | $ Change |
| Operational expenditures | $119.5 | $63.1 | $56.4 |
| Seismic, leasehold and other | 7.6 | — | 7.6 |
| Capitalized general and administrative costs | 7.7 | 6.2 | 1.5 |
| Capitalized interest | 11.2 | 6.0 | 5.2 |
| Total capital expenditures[(a)] | 146.0 | 75.3 | 70.7 |
| | | | |
| Acquisitions | 706.5 | 284.0 | 422.5 |
| Acquisition deposits | (46.1) | — | (46.1) |
| Proceeds from the sale of mineral interest and equipment | — | (23.6) | 23.6 |
| Total investing activities | $806.4 | $335.7 | $470.7 |

(a) On an accrual (GAAP) basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the six months ended June 30, 2017 were $163.6 million. Inclusive of capitalized general and administrative and interest costs, total capital expenditures for the six months ended June 30, 2017 were $194.4 million.

General and administrative expenses and capitalized interest are discussed below in Results of Operations. See Note 2 in the Footnotes to the Financial Statements for additional information on acquisitions.

Financing activities. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility, term debt and equity offerings. For the six months ended June 30, 2017, net cash provided by financing activities was $196.8 million compared to $295.2 million for the same period of 2016. The change was predominantly attributable to the following:

- A $201.5 million increase in borrowings on fixed-rate debt, resulting from the issuance of $200 million of 6.125% senior unsecured notes due 2024, including a premium issue price of 104.125% and net of payments of deferred financing costs
- We had no issuance of common stock during the six months ended June 30, 2017, a change of $300.8 million compared to the same period of 2016.

Net cash provided by financing activities includes the following for the periods indicated (in millions):

| | Six Months Ended June 30, 2017 | | |
|---|---|---|---|
| | 2017 | 2016 | $ Change |
| Net borrowings on senior secured revolving credit facility | $— | $— | $— |
| Issuance of 6.125% senior unsecured notes due 2024 | 200.0 | — | 200.0 |
| Premium on the issuance of 6.125% senior unsecured notes due 2024 | 8.3 | — | 8.3 |
| Issuance of common stock | — | 300.8 | (300.8 ) |
| Payment of preferred stock dividends | (3.7 ) | (3.7 ) | — |
| Payment of deferred financing costs | (6.8 ) | — | (6.8 ) |
| Tax withholdings related to restricted stock units | (1.0 ) | (2.0 ) | 1.0 |
| Net cash provided by financing activities | $196.8 | $295.1 | $(98.3 ) |

See Notes 4 and 9 in the Footnotes to the Financial Statements for additional information on our debt and equity offerings.

Capital Plan and Year to Date 2017 Summary

Our operational capital budget for 2017 was established at $350 million on an accrual, or GAAP, basis, inclusive of a transition from a three-rig program that commenced in January 2017 to a four-rig program in July 2017 that includes horizontal development activity at our recent Delaware Basin acquisition (see Note 2 in the Footnotes to the Financial Statements for information on this acquisition).

In addition to the operational capital budget, which includes well costs, facilities and infrastructure capital, and surface land purchases, we budgeted an estimated $40 to $45 million for capitalized general and administrative expenses and capitalized interest expenses, both on an accrual, or GAAP, basis.

Operational capital expenditures on an accrual basis were $163.6 million for the six months ended June 30, 2017. In addition to the operational capital expenditures, $8.7 million of capitalized general and administrative and $14.5 million of capitalized interest expenses were accrued in the six months ended June 30, 2017.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop our reserves of oil and natural gas. We believe the long-term outlook for our business is favorable due to our resource base, low cost structure, financial strength, risk management, including commodity hedging strategy, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

Results of Operations

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

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | 2016 | Change | % Change |
| Net production: | | | | |
| Oil (MBbls) | 1,596 | 948 | 648 | 68 % |
| Natural gas (MMcf) | 2,550 | 1,658 | 892 | 54 % |
| Total (MBOE) | 2,021 | 1,224 | 797 | 65 % |
| Average daily production (BOE/d) | 22,209 | 13,451 | 8,758 | 65 % |
| % oil (BOE basis) | 79 % | 77 % | | |
| Average realized sales price: | | | | |
| Oil (Bbl) (excluding impact of cash settled derivatives) | $45.67 | $42.78 | $2.89 | 7 % |
| Oil (Bbl) (including impact of cash settled derivatives) | 45.47 | 46.69 | (1.22) | (3)% |
| Natural gas (Mcf) (excluding impact of cash settled derivatives) | $3.69 | $2.77 | $0.92 | 33 % |
| Natural gas (Mcf) (including impact of cash settled derivatives) | 3.70 | 2.96 | 0.74 | 25 % |
| Total (BOE) (excluding impact of cash settled derivatives) | $40.71 | $36.88 | $3.83 | 10 % |
| Total (BOE) (including impact of cash settled derivatives) | 40.58 | 40.17 | 0.41 | 1 % |
| Oil and natural gas revenues (in thousands): | | | | |
| Oil revenue | $72,885 | $40,555 | $32,330 | 80 % |
| Natural gas revenue | 9,398 | 4,590 | 4,808 | 105 % |
| Total | $82,283 | $45,145 | $37,138 | 82 % |
| Additional per BOE data: | | | | |
| Sales price (excluding impact of cash settled derivatives) | $40.71 | $36.88 | $3.83 | 10 % |
| Lease operating expense (excluding gathering and treating expense) | 5.56 | 5.70 | (0.14) | (2)% |
| Gathering and treating expense | 0.45 | 0.27 | 0.18 | 67 % |
| Production taxes | 2.38 | 2.01 | 0.37 | 18 % |
| Operating margin | $32.32 | $28.90 | $3.42 | 12 % |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | 2016 | Change | % Change |
| Net production: | | | | |
| Oil (MBbls) | 3,030 | 1,840 | 1,190 | 65 % |
| Natural gas (MMcf) | 4,980 | 3,101 | 1,879 | 61 % |
| Total (MBOE) | 3,860 | 2,357 | 1,503 | 64 % |
| Average daily production (BOE/d) | 21,326 | 12,951 | 8,375 | 65 % |
| % oil (BOE basis) | 79 % | 78 % | | |
| Average realized sales price: | | | | |
| Oil (Bbl) (excluding impact of cash settled derivatives) | $47.82 | $36.96 | $10.86 | 29 % |
| Oil (Bbl) (including impact of cash settled derivatives) | 46.88 | 43.05 | 3.83 | 9 % |
| Natural gas (Mcf) (excluding impact of cash settled derivatives) | $3.77 | $2.53 | $1.24 | 49 % |
| Natural gas (Mcf) (including impact of cash settled derivatives) | 3.78 | 2.70 | 1.08 | 40 % |
| Total (BOE) (excluding impact of cash settled derivatives) | $42.40 | $32.18 | $10.22 | 32 % |
| Total (BOE) (including impact of cash settled derivatives) | 41.68 | 37.16 | 4.52 | 12 % |

| | | | | | |
|---|---|---|---|---|---|
| Oil and natural gas revenues (in thousands): | | | | | |
| Oil revenue | $144,893 | $67,998 | $76,895 | 113 | % |
| Natural gas revenue | 18,754 | 7,845 | 10,909 | 139 | % |
| Total | $163,647 | $75,843 | $87,804 | 116 | % |
| Additional per BOE data: | | | | | |
| Sales price (excluding impact of cash settled derivatives) | $42.40 | $32.18 | $10.22 | 32 | % |
| Lease operating expense (excluding gathering and treating expense) | 6.06 | 5.82 | 0.24 | 4 | % |
| Gathering and treating expense | 0.44 | 0.23 | 0.21 | 91 | % |
| Production taxes | 2.78 | 1.98 | 0.80 | 40 | % |
| Operating margin | $33.12 | $24.15 | $8.97 | 37 | % |

Revenues

The following table reconciles the change in oil, natural gas and total revenue for the respective periods presented by reflecting the effect of changes in volume and in the underlying commodity prices.

| (in thousands) | Oil | Natural Gas | Total |
|---|---|---|---|
| Revenues for the three months ended June 30, 2016 | $40,555 | $4,590 | $45,145 |
| Volume increase | 27,721 | 2,471 | 30,192 |
| Price increase | 4,609 | 2,337 | 6,946 |
| Net increase | 32,330 | 4,808 | 37,138 |
| Revenues for the three months ended June 30, 2017 | $72,885 | $9,398 | $82,283 |

| (in thousands) | Oil | Natural Gas | Total |
|---|---|---|---|
| Revenues for the six months ended June 30, 2016 | $67,998 | $7,845 | $75,843 |
| Volume increase | 43,982 | 4,754 | 48,736 |
| Price increase | 32,913 | 6,155 | 39,068 |
| Net increase | 76,895 | 10,909 | 87,804 |
| Revenues for the six months ended June 30, 2017 | $144,893 | $18,754 | $163,647 |

Commodity prices

The prices for oil and natural gas can be volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and actions by the Organization of Petroleum Exporting Countries and other countries and government actions. Prices of oil and natural gas will affect the following aspects of our business:

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

For the three and six months ended June 30, 2017, the average NYMEX price for a barrel of oil was $48.15 and $49.95 per Bbl compared to $45.59 and $39.68 per Bbl for the same periods of 2016, respectively. The NYMEX price for a barrel of oil for the three and six months ended June 30, 2017 ranged from a low of $42.53 per Bbl to a high of $53.40 per Bbl and a low of $42.53 per Bbl to a high of $54.45 Bbl, respectively.

For the three and six months ended June 30, 2017, the average NYMEX price for natural gas was $3.18 and $3.25 per MMBtu compared to $1.95 and $2.02 per MMBtu for the same periods of 2016. The NYMEX price for natural gas for the three and six months ended June 30, 2017 ranged from a low of $2.89 per MMBtu to a high of $3.42 per MMBtu and a low of $2.56 per MMBtu to a high of $3.42 MMBtu, respectively.

Oil revenue

For the quarter ended June 30, 2017, oil revenues of $72.9 million increased $32.3 million, or 80%, compared to revenues of $40.6 million for the same period of 2016. The increase in oil revenue was primarily attributable to a 68% increase in production and a 7% increase in the average realized sales price, which rose to $45.67 per Bbl in the second quarter of 2017 from $42.78 per Bbl in the second quarter of 2016. The increase in production was attributable to 698 MBbls from wells placed on production as a result of our horizontal drilling program and 314 MBbls from producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

For the six months ended June 30, 2017, oil revenues of $144.9 million increased $76.9 million, or 113%, compared to revenues of $68.0 million for the same period of 2016. The increase in oil revenue was primarily attributable to a 65% increase in production and a 29% increase in the average realized sales price, which rose to $47.82 per Bbl for the six months ended June 30, 2017 from $36.96 per Bbl for the same period of 2016. The increase in production was comprised of 1,293 MBbls attributable to wells placed on production as a result of our horizontal drilling program and 627 MBbls attributable to producing wells added from our acquired properties. Offsetting these increases were normal and expected declines from our existing wells.

See Note 2 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions.

Natural gas revenue (including NGLs)

Natural gas revenues of $9.4 million increased $4.8 million, or 105%, during the three months ended June 30, 2017, compared to $4.6 million for the same period of 2016. The increase primarily relates to a 54% increase in natural gas volumes and a 33% increase in the average realized sales price, which rose to $3.69 per Mcf from $2.77 per Mcf, reflecting both natural gas and natural gas liquids prices. The increase in production was comprised of 791 MMcf attributable to wells placed on production as a result of our horizontal drilling program and 514 MMcf attributable to producing wells added from our acquired properties. Offsetting these increases were normal expected declines from our existing wells.

Natural gas revenues of $18.8 million increased $10.9 million, or 139%, during the six months ended June 30, 2017, compared to $7.8 million for the same period of 2016. The increase primarily relates to a 61% increase in natural gas volumes and a 49% increase in the average realized sales price, which rose to $3.77 per Mcf from $2.53 per Mcf, reflecting both natural gas and natural gas liquids prices. The increase in production was comprised of 1,395 MMcf attributable to wells placed on production as a result of our horizontal drilling program and 1,076 MMcf attributable to producing wells added from our acquired properties. Offsetting these increases were normal expected declines from our existing wells.

See Note 2 in the Footnotes to the Financial Statements for additional information regarding the Company's acquisitions.

Operating Expenses

| (in thousands, except per unit amounts) | Three Months Ended June 30, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Per | | Per | Total Change | | BOE Change | |
| | 2017 | BOE | 2016 | BOE | $ | % | $ | % |
| Lease operating expenses | $12,145 | $6.01 | $7,311 | $5.97 | $4,834 | 66 % | $0.04 | 1 % |
| Production taxes | 4,820 | 2.38 | 2,455 | 2.01 | 2,365 | 96 % | 0.37 | 18 % |
| Depreciation, depletion and amortization | 26,213 | 12.97 | 16,293 | 13.31 | 9,920 | 61 % | (0.34 ) | (3 )% |
| General and administrative | 6,430 | 3.18 | 6,302 | 5.15 | 128 | 2 % | (1.97 ) | (38)% |
| Settled share-based awards | 6,351 | nm | — | nm | 6,351 | nm | nm | nm |
| Accretion expense | 208 | 0.10 | 395 | 0.32 | (187 ) | (47 )% | (0.22 ) | (69)% |
| Write-down of oil and natural gas properties | — | nm | 61,012 | nm | (61,012 ) | nm | nm | nm |
| Acquisition expense | 2,373 | nm | 1,906 | nm | 467 | nm | nm | nm |

| (in thousands, except per unit amounts) | Six Months Ended June 30, | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Per | | Per | Total Change | | BOE Change | |
| | 2017 | BOE | 2016 | BOE | $ | % | $ | % |
| Lease operating expenses | $25,084 | $6.50 | $14,268 | $6.05 | $10,816 | 76 % | $0.45 | 7 % |
| Production taxes | 10,723 | 2.78 | 4,675 | 1.98 | 6,048 | 129 % | 0.80 | 40 % |
| Depreciation, depletion and amortization | 50,646 | 13.12 | 32,015 | 13.58 | 18,631 | 58 % | (0.46 ) | (3 )% |
| General and administrative | 11,636 | 3.01 | 11,864 | 5.03 | (228 ) | (2 )% | (2.02 ) | (40)% |
| Settled share-based awards | 6,351 | nm | — | nm | 6,351 | nm | nm | nm |
| Accretion expense | 392 | 0.10 | 575 | 0.24 | (183 ) | (32 )% | (0.14 ) | (58)% |
| Write-down of oil and natural gas properties | — | nm | 95,788 | nm | (95,788 ) | nm | nm | nm |
| Acquisition expense | 2,822 | nm | 1,954 | nm | 868 | nm | nm | nm |

nm = not meaningful

Lease operating expenses (“LOE”). These are daily costs incurred to extract oil and natural gas, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs, gas treating fees, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

For the three months ended June 30, 2017, LOE increased by 66% to $12.1 million compared to $7.3 million for the same period of 2016. Contributing to the increase was $4.6 million related to oil and natural gas properties acquired during 2016 and the first half of 2017 (see Note 2 in the Footnotes to the Financial Statements). Excluding LOE related to these acquired properties, LOE increased by $0.2 million, or 3%, compared to the same period of 2016, which was primarily due to an increase in cost driven by higher production volumes from our legacy assets. For the three months ended June 30, 2017, LOE per BOE increased to $6.01 per BOE compared to $5.97 per BOE for the same period of 2016, which was primarily attributable to an increase in cost as previously discussed offset by higher production volumes. The increase in production was primarily attributable to an increased number of producing wells from our horizontal drilling program and acquisitions as discussed above.

For the six months ended June 30, 2017, LOE increased by 76% to $25.1 million compared to $14.3 million for the same period of 2016. Contributing to the increase was $9.3 million related to oil and natural gas properties acquired during 2016 and the first half of 2017 (see Note 2 in the Footnotes to the Financial Statements). Excluding LOE related to these acquired properties, LOE increased by $1.5 million, or 11%, compared to the same period of 2016, which was primarily due to an increase in cost driven by higher production volumes from our legacy assets. For the six months ended June 30, 2017, LOE per BOE increased to $6.50 per BOE compared to $6.05 per BOE for the same period of 2016, which was primarily attributable to an increase in cost as previously discussed offset by higher production volumes. The increase in production was primarily attributable to an increased number of producing wells from our horizontal drilling program and acquisitions as discussed above.

Production taxes. Production taxes include severance and ad valorem taxes. In general, production taxes are directly related to commodity price changes; however, severance taxes are based upon current year commodity prices, whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

Production taxes for the three months ended June 30, 2017 increased by 96% to $4.8 million compared to $2.5 million for the same period of 2016. The increase was primarily due to an increase in severance taxes, which was attributable to the increase in revenue. Also contributing to the increase was an increase in ad valorem taxes, which was attributable to an increase in the valuation of our oil and gas properties by taxing jurisdictions as a result of an increased number of producing wells from our horizontal drilling program, acquisitions as discussed above, and an increase in commodity prices year over year. On a per BOE basis, production taxes for the three months ended June 30, 2017 increased by 18% compared to the same period of 2016.

Production taxes for the six months ended June 30, 2017 increased by 129% to $10.7 million compared to $4.7 million for the same period of 2016. The increase was primarily due to an increase in severance taxes, which was attributable to the increase in revenue. Also contributing to the increase was an increase in ad valorem taxes, which was attributable to an increase in the valuation of our oil and gas properties by taxing jurisdictions as a result of an increased number of producing wells from our horizontal drilling program, acquisitions as discussed above, and an increase in commodity prices year over year. On a per BOE basis, production taxes for the three months ended June 30, 2017 increased by 40% compared to the same period of 2016.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unevaluated properties, less accumulated amortization; (ii) the estimated future expenditures to be incurred in developing proved reserves; and (iii) the estimated dismantlement and abandonment costs, net of estimated salvage values. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years.

For the three months ended June 30, 2017, DD&A increased 61% to $26.2 million compared to $16.3 million for the same period of 2016. The increase is primarily attributable to a 65% increase in production offset by a 3% decrease in our per BOE DD&A rate. For the three months ended June 30, 2017, DD&A on a per unit basis decreased to $12.97 per BOE compared to $13.31 per BOE for the same period of 2016. The decrease is attributable to our increased estimated proved reserves relative to our depreciable base and assumed future development costs related to undeveloped proved reserves as a result of additions made through our horizontal drilling efforts and acquisitions, offset by the write down of oil and natural gas properties in the first half of 2016.

For the six months ended June 30, 2017, DD&A increased 58% to $50.6 million compared to $32.0 million for the same period of 2016. The increase is primarily attributable to a 64% increase in production offset by a 3% decrease in our per BOE DD&A rate. For the six months ended June 30, 2017, DD&A on a per unit basis decreased to $13.12 per BOE compared to $13.58 per BOE for the same period of 2016. The decrease is attributable to our increased estimated proved reserves relative to our depreciable base and assumed future development costs related to undeveloped proved reserves as a result of additions made through our horizontal drilling efforts and acquisitions, offset by the write down of oil and natural gas properties in the first half of 2016.

General and administrative, net of amounts capitalized (“G&A”). These are costs incurred for overhead, including payroll and benefits for our corporate staff, severance and early retirement expenses, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, depreciation of corporate level assets, public company costs, vesting of equity and liability awards under share-based compensation plans and related mark-to-market valuation adjustments over time, fees for audit and other professional services, and legal compliance.

G&A for the three months ended June 30, 2017 increased to $6.4 million compared to $6.3 million for the same period of 2016. G&A expenses for the periods indicated include the following (in millions):

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | 2016 | $ Change | % Change |
| Recurring expenses | | | | |
| G&A | $5.5 | $3.7 | $ 1.8 | 49 % |
| Share-based compensation | 1.0 | 0.6 | 0.4 | 67 % |
| Fair value adjustments of cash-settled RSU awards | (0.6 ) | 2.0 | (2.6 ) | (130 )% |
| Non-recurring expenses | | | | |
| Early retirement expenses | 0.4 | — | 0.4 | 100 % |
| Early retirement expenses related to share-based compensation | 0.1 | — | 0.1 | 100 % |
| Total G&A expenses | $6.4 | $6.3 | $ 0.1 | 2 % |

G&A for the six months ended June 30, 2017 decreased to $11.6 million compared to $11.9 million for the same period of 2016. G&A expenses for the periods indicated include the following (in millions):

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | 2017 | 2016 | $ Change | % Change |
| Recurring expenses | | | | |
| G&A | $10.1 | $7.8 | $ 2.3 | 29 % |
| Share-based compensation | 1.9 | 1.2 | 0.7 | 58 % |
| Fair value adjustments of cash-settled RSU awards | (0.9 ) | 2.7 | (3.6 ) | (133 )% |
| Non-recurring expenses | | | | |
| Early retirement expenses | 0.4 | — | 0.4 | 100 % |
| Early retirement expenses related to share-based compensation | 0.1 | — | 0.1 | 100 % |
| Expense related to a threatened proxy contest | — | 0.2 | (0.2 ) | (100 )% |
| Total G&A expenses | $11.6 | $11.9 | $ (0.3 ) | (3 )% |

Settled share-based awards. In June 2017, the Company settled the outstanding share-based award agreements of its former Chief Executive Officer, resulting in $6.4 million recorded on the Consolidated Statements of Operations as Settled share-based awards.

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

Accretion expense related to our ARO decreased 47% and 32% for the three and six months ended June 30, 2017, compared to the same period of 2016. Accretion expense generally correlates with the Company’s ARO, which was $6.8 million at June 30, 2017 as compared to $6.1 million at June 30, 2016. See Note 8 in the Footnotes to the Financial Statements for additional information regarding the Company’s ARO.

Acquisition expense. Acquisition expense for the three months ended June 30, 2017 was related to costs with respect to our acquisition efforts in the Permian Basin. See Note 2 in the Footnotes to the Financial Statements for additional information regarding the Company’s acquisitions.

Write-down of oil and natural gas properties. Under full cost accounting rules, the Company reviews the carrying value of its proved oil and natural gas properties each quarter. Under these rules, capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full cost ceiling amount). These rules require pricing based on the preceding 12-months' average oil and natural gas prices based on closing prices on the first day of each month and require a write-down if the net capitalized costs of proved oil and natural gas properties exceeds the full cost ceiling.

For the three and six months ended June 30, 2017, the Company did not recognize write-downs of oil and natural gas properties compared to write-downs of $61.0 million and $95.8 million for the same periods of 2016, respectively, as a result of the ceiling test limitation. At June 30, 2017, the average prices used in determining the estimated future net cash flows from proved reserves were $48.95 per barrel of oil and $3.01 per Mcf of natural gas. If commodity prices were to decline, we could incur additional ceiling test write-downs in the future.

The table below presents the cumulative results of the full cost ceiling test along with various pricing scenarios to demonstrate the sensitivity of our full cost ceiling to changes in 12-month average oil and natural gas prices. This sensitivity analysis is as of June 30, 2017, and accordingly, does not consider drilling results, production, changes in oil and natural gas prices, and changes in future development and operating costs subsequent to June 30, 2017 that may require revisions to our proved reserve estimates and resulting estimated future net cash flows used in the full cost ceiling test.

| | 12-Month Average Prices | | Excess (Deficit) of Full Cost Ceiling Over Net Capitalized Costs |
|---|---|---|---|
| Pricing Scenarios | Oil ($/Bbl) | Natural gas ($/Mcf) | (in thousands) |
| June 30, 2017 Actual | $ 48.95 | $ 3.01 | $ 291,266 |
| Combined price sensitivity | | | |
| Oil and natural gas +10% | $ 53.85 | $ 3.31 | $ 526,973 |
| Oil and natural gas -10% | $ 44.06 | $ 2.71 | 50,660 |
| Oil price sensitivity | | | |
| Oil +10% | $ 53.85 | $ 3.01 | $ 505,082 |
| Oil -10% | $ 44.06 | 3.01 | 72,551 |
| Natural gas sensitivity | | | |
| Natural gas +10% | $ 48.95 | $ 3.31 | $ 312,252 |
| Natural gas -10% | 48.95 | $ 2.71 | 265,381 |

Other Income and Expenses and Preferred Stock Dividends

| (in thousands) | Three Months Ended June 30, 2017 | 2016 | $ Change | % Change |
|---|---|---|---|---|
| Interest expense, net of capitalized amounts | $589 | $4,180 | $(3,591) | (86)% |
| (Gain) loss on derivative contracts | (10,494) | 15,484 | (25,978) | (168)% |
| Other income | (64) | (96) | 32 | (33)% |
| Total | $(9,969) | $19,568 | | |
| | | | | |
| Income tax expense | $322 | $— | $322 | (100)% |
| Preferred stock dividends | (1,824) | (1,823) | (1) | — % |

| (in thousands) | Six Months Ended June 30, 2017 | 2016 | $ Change | % Change |
|---|---|---|---|---|
| Interest expense, net of capitalized amounts | $1,254 | $9,671 | $(8,417) | (87)% |
| (Gain) loss on derivative contracts | (25,797) | 16,416 | (42,213) | (257)% |
| Other income | (772) | (177) | (595) | 336 % |
| Total | $(25,315) | $25,910 | | |
| | | | | |
| Income tax expense | $789 | $— | $789 | (100)% |
| Preferred stock dividends | (3,647) | (3,647) | — | — % |

Interest expense, net of capitalized amounts. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Interest expense, net of capitalized amounts, incurred during the three months ended June 30, 2017 decreased $3.6 million compared to the same period of 2016. The decrease is primarily attributable to a $4.4 million increase in capitalized interest compared to the 2016 period, resulting from a higher average unevaluated property balance for the three months ended June 30, 2017 as compared to the same period of 2016. The increase in unevaluated property was primarily due to acquired properties. Offsetting the decrease was a $0.8 million increase in interest expense on our Credit Facility and term debt.

Interest expense, net of capitalized amounts, incurred during the six months ended June 30, 2017 decreased $8.4 million compared to the same period of 2016. The decrease is primarily attributable to an $8.6 million increase in capitalized interest compared to the 2016 period, resulting from a higher average unevaluated property balance for the six months ended June 30, 2017 as compared to the same period of 2016. The increase in unevaluated property was primarily due to acquired properties. Offsetting the decrease was a $0.1 million increase in interest expense on our Credit Facility and term debt.

See Notes 2 and 4 in the Footnotes to the Financial Statements for additional information on our acquisitions and debt.

Gain (loss) on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. This amount represents the (i) gain (loss) related to fair value adjustments on our open derivative contracts and (ii) gains (losses) on settlements of derivative contracts for positions that have settled within the period.

For the three months ended June 30, 2017, the net gain on derivative contracts was $10.5 million compared to a $15.5 million net loss for the same period of 2016. The net gain (loss) on derivative instruments for the periods indicated includes the following (in millions):

| | Three Months Ended June 30, | |
|---|---|---|
| | 2017 | 2016 |
| Oil derivatives | | |
| Net gain (loss) on settlements | $(0.3) | $3.7 |
| Net gain (loss) on fair value adjustments | 10.1 | (18.5) |
| Total gain (loss) on oil derivatives | $9.8 | $(14.8) |
| Natural gas derivatives | | |
| Net gain on settlements | $— | $0.3 |
| Net gain (loss) on fair value adjustments | 0.6 | (1.0) |
| Total gain (loss) on natural gas derivatives | $0.6 | $(0.7) |
| Total gain (loss) on oil & natural gas derivatives | $10.4 | $(15.5) |

For the six months ended June 30, 2017, the net gain on derivative contracts was $25.8 million compared to a $16.4 million net loss for the same period of 2016. The net gain (loss) on derivative instruments for the periods indicated includes the following (in millions):

| | Six Months Ended June 30, | |
|---|---|---|
| | 2017 | 2016 |
| Oil derivatives | | |
| Net gain (loss) on settlements | $(2.8) | $11.2 |
| Net gain (loss) on fair value adjustments | 27.4 | (27.6) |
| Total gain (loss) on oil derivatives | $24.6 | $(16.4) |
| Natural gas derivatives | | |
| Net gain on settlements | $0.1 | $0.5 |
| Net gain (loss) on fair value adjustments | 1.2 | (0.5) |
| Total gain on natural gas derivatives | $1.3 | $— |
| Total gain (loss) on oil & natural gas derivatives | $25.9 | $(16.4) |

See Notes 5 and 6 in the Footnotes to the Financial Statements for additional information on the Company's derivative contracts and disclosures related to derivative instruments.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

The Company had income tax expense of $0.3 million and $0.8 million for the three and six months ended June 30, 2017, compared to no benefit or expense for the same periods of 2016, respectively. The change in income tax expense is primarily related to deferred state income tax expense. The Company had a valuation allowance of $115.9 million as of June 30, 2017. See Note 8 in the Footnotes to the Financial Statements for additional information.

Preferred Stock dividends. Preferred Stock dividends of $1.8 million and $3.6 million for the three and six months ended June 30, 2017 were consistent with dividends for the same periods of 2016, respectively. Dividends reflect a 10% dividend rate. See Note 9 in the Footnotes to the Financial Statements for additional information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes which we hedge through use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 40% to 60% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices, in addition to modification of our capital spending plans related to operational activities and acquisitions.

The Company's hedging portfolio, linked to NYMEX benchmark pricing, covers approximately 2,261 MBbls and 2,452 MMBtu of our expected oil and natural gas production, respectively, for the remaining six months of 2017. We also have commodity hedging contracts linked to Midland WTI basis differentials relative to Cushing covering approximately 1,104 MBbls of our expected oil production for the remaining six months of 2017. See Note 5 in the Footnotes to the Financial Statements for a description of the Company's outstanding derivative contracts at June 30, 2017, and derivative contracts established subsequent to that date.

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

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

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

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

Interest rate risk

The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. Though we had no balance outstanding on our Credit Facility at June 30, 2017, based on a notional amount of $10 million outstanding under the facility, an increase or decrease of 1% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $0.1 million. See Note 4 to the Consolidated Financial Statements for more information on the Company's interest rates on its Credit Facility.

Counterparty and customer credit risk

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

The Company markets its oil and natural gas production to energy marketing companies. We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require any of our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. At June 30, 2017 our total receivables from the sale of our oil and natural gas production were approximately $46.2 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At June 30, 2017 our joint interest receivables were approximately $30.2 million.

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

## Item 4. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is accumulated and communicated to the issuer’s management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company’s disclosure controls and procedures were effective as of June 30, 2017.

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 2016 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

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 through May 12, 2016 (incorporated by reference to Exhibit 3.1 of the Company’s Quarterly Report on Form 10-Q, filed on November 3, 2016) |
| 3.2 | | Certificate of Designation of Rights and Preferences of 10% Series A Cumulative Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company’s Form 8-A, filed on May 23, 2013) |
| 3.3 | | Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company’s Registration Statement on Form S-4, filed on August 4, 1994, Reg. No. 33-82408) |
| 4. | | Instruments defining the rights of security holders, including indentures |
| 4.1 | | Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company’s Registration Statement on Form S-4, filed on August 4, 1994, Reg. No. 33-82408) |
| 4.2 | | Certificate for the Company’s 10% Cumulative Preferred Stock (incorporated by reference to Exhibit 4.1 of the Company’s Form 8-A, filed on May 23, 2013) |
| 4.3 | | Indenture of 6.125% Senior Notes Due 2024, dated as of October 3, 2016, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on October 4, 2016) |
| 4.4 | | Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated May 24, 2017, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on May 24, 2017) |
| 10. | | Material Contracts |
| 10.1 | (a) | Amended and Restated Credit Facility, dated May 31, 2017 |
| 10.2 | | Purchase Agreement dated as of May 19, 2017, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities, LLC, as representatives of the Initial Purchasers (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on May 24, 2017) |
| 31. | | Section 13a-14 Certifications |
| 31.1 | (a) | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2 | (a) | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32. | | Section 1350 Certifications |
| 32.1 | (b) | Section 1350 Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| 101. | (c) | Interactive Data Files |

(a) Filed herewith.

(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

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

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SIGNATURES

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

Callon Petroleum Company

| Signature | Title | Date |
|---|---|---|
| /s/ Joseph C. Gatto, Jr.<br>Joseph C. Gatto, Jr. | President and<br>Chief Executive Officer | August 2, 2017 |
| /s/ Correne S. Loeffler<br>Correne S. Loeffler | Treasurer and<br>Interim Chief Financial Officer | August 2, 2017 |