Vanguard Natural Resources, LLC
Form 10-Q
May 04, 2015

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

FORM 10-Q

(Mark One)

| | |
|---|---|
| x | QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 |

For the quarterly period ended March 31, 2015
OR

| | |
|---|---|
| o | TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 |

For the transition period from to
Commission File Number: 001-33756
Vanguard Natural Resources, LLC
(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| Delaware<br>(State or Other Jurisdiction of<br>Incorporation or Organization) | 61-1521161<br>(I.R.S. Employer<br>Identification No.) |
| 5847 San Felipe, Suite 3000<br>Houston, Texas | 77057 |
| (Address of Principal Executive Offices) | (Zip Code) |

(832) 327-2255
(Registrant's Telephone Number, Including Area Code)

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

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

| | | | |
|---|---|---|---|
| x | Large accelerated filer | o | Accelerated filer |
| o | Non-accelerated filer<br>(Do not check if a smaller reporting company) | o | Smaller reporting company |

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

Common units outstanding on April 27, 2015: 85,959,185.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
TABLE OF CONTENTS


| | | Page |
|---|---|---|
| PART I – FINANCIAL INFORMATION | | |
| Item 1. | Unaudited Financial Statements | |
| | Consolidated Statements of Operations | 3 |
| | Consolidated Balance Sheets | 4 |
| | Consolidated Statements of Members' Equity | 5 |
| | Consolidated Statements of Cash Flows | 6 |
| | Notes to Consolidated Financial Statements | 7 |
| Item 2. | Management's Discussion and Analysis of Financial Condition and Results of Operations | 27 |
| Item 3. | Quantitative and Qualitative Disclosures About Market Risk | 40 |
| Item 4. | Controls and Procedures | 45 |
| PART II – OTHER INFORMATION | | |
| Item 1. | Legal Proceedings | 46 |
| Item 1A. | Risk Factors | 46 |
| Item 2. | Unregistered Sales of Equity Securities and Use of Proceeds | 46 |
| Item 3. | Defaults Upon Senior Securities | 46 |
| Item 4. | Mine Safety Disclosures | 46 |
| Item 5. | Other Information | 46 |
| Item 6. | Exhibits | 46 |

## GLOSSARY OF TERMS

Below is a list of terms that are common to our industry and used throughout this document:

| | | | |
|---|---|---|---|
| /day | = per day | Mcf | = thousand cubic feet |
| Bbls | = barrels | Mcfe | = thousand cubic feet of natural gas equivalents |
| Bcf | = billion cubic feet | MMBbls | = million barrels |
| Bcfe | = billion cubic feet equivalents | MMBOE | = million barrels of oil equivalent |
| BOE | = barrel of oil equivalent | MMBtu | = million British thermal units |
| Btu | = British thermal unit | MMcf | = million cubic feet |
| MBbls | = thousand barrels | MMcfe | = million cubic feet equivalent |
| MBOE | = thousand barrels of oil equivalent | NGLs | = natural gas liquids |

When we refer to oil, natural gas and NGLs in “equivalents,” we are doing so to compare quantities of natural gas with quantities of NGLs and oil or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which 42 gallons is equal to one Bbl of oil or one Bbl of NGLs and one Bbl of oil or one Bbl of NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

References in this report to “us,” “we,” “our,” the “Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC (“VNG” or “our operating subsidiary”), VNR Holdings, LLC (“VNRH”), Vanguard Permian, LLC (“Vanguard Permian”), Vanguard Operating, LLC (“VO”), VNR Finance Corp. (“VNRF”), Encore Energy Partners Operating LLC (“OLLC”) and Encore Clear Fork Pipeline LLC.

## Forward-Looking Statements

Certain statements and information in this Quarterly Report on Form 10-Q may constitute “forward-looking statements.” Statements included in this Quarterly Report on Form 10-Q that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), including, without limitation, the information set forth in Management’s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “may,” “believe,” “expect,” “intend,” “anticipate,” “estimate,” “continue,” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in the Risk Factors section of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the “2014 Annual Report”), and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the Securities and Exchange Commission (the “SEC”), which are available on our website at www.vnrllc.com and through the SEC’s Electronic Data Gathering and Retrieval System at www.sec.gov.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I – FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)
(Unaudited)

| | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| Revenues: | | |
| Oil sales | $35,790 | $68,199 |
| Natural gas sales | 55,754 | 63,543 |
| NGLs sales | 7,350 | 20,998 |
| Net gains (losses) on commodity derivative contracts | 59,033 | (56,037) |
| Total revenues | 157,927 | 96,703 |
| Costs and expenses: | | |
| Production: | | |
| Lease operating expenses | 35,478 | 30,421 |
| Production and other taxes | 11,426 | 15,034 |
| Depreciation, depletion, amortization, and accretion | 66,840 | 43,610 |
| Impairment of oil and natural gas properties | 132,610 | — |
| Selling, general and administrative expenses | 9,051 | 8,038 |
| Total costs and expenses | 255,405 | 97,103 |
| Loss from operations | (97,478) | (400) |
| Other income (expense): | | |
| Interest expense | (20,189) | (16,259) |
| Net losses on interest rate derivative contracts | (1,203) | (458) |
| Gain on acquisition of oil and natural gas properties | — | 32,114 |
| Other | 40 | 124 |
| Total other income (expense) | (21,352) | 15,521 |
| Net income (loss) | $(118,830) | $15,121 |
| Distributions to Preferred unitholders | (6,690) | (1,962) |
| Net income (loss) attributable to Common and Class B unitholders | $(125,520) | $13,159 |
| Net income (loss) per Common and Class B units | | |
| Basic | $(1.49) | $0.17 |
| Diluted | $(1.49) | $0.16 |
| Weighted average Common units outstanding | | |
| Common units – basic | 83,744 | 79,186 |
| Common units – diluted | 83,744 | 79,472 |
| Class B units – basic & diluted | 420 | 420 |

See accompanying notes to consolidated financial statements

3

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit data)
(Unaudited)

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash and cash equivalents | $14,523 | $— |
| Trade accounts receivable, net | 83,663 | 140,017 |
| Derivative assets | 148,898 | 142,114 |
| Other current assets | 3,736 | 4,102 |
| Total current assets | 250,820 | 286,233 |
| | | |
| Oil and natural gas properties, at cost | 4,166,553 | 4,140,527 |
| Accumulated depletion, amortization and impairment | (1,360,595) | (1,164,721) |
| Oil and natural gas properties evaluated, net – full cost method | 2,805,958 | 2,975,806 |
| | | |
| Other assets | | |
| Goodwill | 420,955 | 420,955 |
| Derivative assets | 100,957 | 83,583 |
| Other assets | 25,705 | 27,015 |
| Total assets | $3,604,395 | $3,793,592 |
| | | |
| Liabilities and members' equity | | |
| Current liabilities | | |
| Accounts payable: | | |
| Trade | $8,809 | $15,118 |
| Affiliates | 1,025 | 823 |
| Accrued liabilities: | | |
| Lease operating | 16,589 | 19,822 |
| Development capital | 14,685 | 24,706 |
| Interest | 22,346 | 11,517 |
| Production and other taxes | 39,905 | 29,981 |
| Derivative liabilities | 3,868 | 3,583 |
| Oil and natural gas revenue payable | 33,678 | 40,117 |
| Distribution payable | 11,050 | 18,640 |
| Other | 12,804 | 14,297 |
| Total current liabilities | 164,759 | 178,604 |
| Long-term debt | 1,901,778 | 1,932,816 |
| Derivative liabilities | 1,025 | 1,380 |
| Asset retirement obligations, net of current portion | 148,591 | 146,676 |
| Other long-term liabilities | 2,182 | — |
| Total liabilities | 2,218,335 | 2,259,476 |
| Commitments and contingencies (Note 7) | | |
| Members' equity (Note 8) | | |
| Cumulative Preferred units, 13,881,873 units issued and outstanding at March 31, 2015 and December 31, 2014 | 335,444 | 335,444 |
| | 1,043,001 | 1,191,057 |

| | | |
|---|---|---|
| Common units, 84,769,537 units issued and outstanding at March 31, 2015 and 83,451,746 at December 31, 2014 | | |
| Class B units, 420,000 issued and outstanding at March 31, 2015 and December 31, 2014 | 7,615 | 7,615 |
| Total members’ equity | 1,386,060 | 1,534,116 |
| Total liabilities and members’ equity | $3,604,395 | $3,793,592 |

See accompanying notes to consolidated financial statements

4

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE THREE MONTHS ENDED MARCH 31, 2015 AND THE YEAR ENDED DECEMBER 31, 2014
(in thousands)
(Unaudited)

| | Cumulative Preferred Units | Common Units | Class B | Total Members' Equity |
|---|---|---|---|---|
| Balance at January 1, 2014 | $61,021 | $1,199,699 | $7,615 | $1,268,335 |
| Issuance of Cumulative Preferred units, net of offering costs of $371 | 274,423 | — | — | 274,423 |
| Issuance of Common units, net of offering costs of $88 | — | 147,814 | — | 147,814 |
| Repurchase of units under the common unit buyback program | | (2,498) | | (2,498) |
| Distributions to Preferred unitholders (see Note 8) | — | (18,197) | — | (18,197) |
| Distributions to Common and Class B unitholders (see Note 8) | — | (207,883) | — | (207,883) |
| Unit-based compensation | — | 7,777 | — | 7,777 |
| Net income | — | 64,345 | — | 64,345 |
| Balance at December 31, 2014 | $335,444 | $1,191,057 | $7,615 | $1,534,116 |
| Issuance of Common units, net of offering costs of $221 | — | 12,213 | — | 12,213 |
| Distributions to Preferred unitholders (see Note 8) | — | (6,690) | — | (6,690) |
| Distributions to Common and Class B unitholders (see Note 8) | — | (37,745) | — | (37,745) |
| Repurchase of units under the common unit buyback program | — | (2,399) | — | (2,399) |
| Unit-based compensation | — | 5,395 | — | 5,395 |
| Net loss | — | (118,830) | — | (118,830) |
| Balance at March 31, 2015 | $335,444 | $1,043,001 | $7,615 | $1,386,060 |

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

| | Three Months Ended March 31, 2015 | 2014 |
|---|---|---|
| Operating activities | | |
| Net income (loss) | $(118,830) | $15,121 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 66,840 | 43,610 |
| Impairment of oil and natural gas properties | 132,610 | — |
| Amortization of debt discount | 70 | 65 |
| Compensation related items | 5,395 | 2,872 |
| Net (gains) losses on commodity and interest rate derivative contracts | (57,830) | 56,495 |
| Cash settlements received (paid) on matured commodity derivative contracts | 38,291 | (11,969) |
| Cash settlements paid on matured interest rate derivative contracts | (990) | (990) |
| Net gain on acquisition of oil and natural gas properties | — | (32,114) |
| Changes in operating assets and liabilities: | | |
| Trade accounts receivable | 56,354 | (18,472) |
| Other current assets | 632 | (365) |
| Premiums paid on commodity derivative contracts | (795) | 3 |
| Accounts payable and oil and natural gas revenue payable | (12,748) | 575 |
| Payable to affiliates | 202 | 25 |
| Accrued expenses and other current liabilities | 3,345 | 24,423 |
| Other assets | 1,104 | 374 |
| Net cash provided by operating activities | 113,650 | 79,653 |
| Investing activities | | |
| Additions to property and equipment | (85) | (228) |
| Additions to oil and natural gas properties | (25,070) | (27,986) |
| Acquisitions of oil and natural gas properties | (694) | (496,663) |
| Deposits and prepayments of oil and natural gas properties | (4) | (299) |
| Net cash used in investing activities | (25,853) | (525,176) |
| Financing activities | | |
| Proceeds from long-term debt | 71,500 | 539,000 |
| Repayment of long-term debt | (102,563) | (238,000) |
| Proceeds from Preferred unit offerings, net | — | 170,026 |
| Proceeds from Common unit offerings, net | 12,213 | 34,545 |
| Repurchase of units under the Common unit buyback program | (2,399) | — |
| Distributions to Preferred unitholders | (6,690) | (1,047) |
| Distributions to Common and Class B unitholders | (45,335) | (49,914) |
| Net cash provided by (used in) financing activities | (73,274) | 454,610 |
| Net increase cash and cash equivalents | 14,523 | 9,087 |
| Cash and cash equivalents, beginning of period | — | 11,818 |
| Cash and cash equivalents, end of period | $14,523 | $20,905 |
| | | |
| Supplemental cash flow information: | | |
| Cash paid for interest | $19,210 | $4,994 |
| Non-cash investing activity: | | |
| Asset retirement obligations, net | $360 | $13,213 |

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Description of the Business:

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, as of March 31, 2015, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Gulf Coast Basin in Texas, Louisiana and Mississippi;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

We were formed in October 2006 and completed our initial public offering in October 2007. Our common units are listed on the NASDAQ Global Select Market ("NASDAQ"), an exchange of the NASDAQ OMX Group Inc. (Nasdaq: NDAQ), under the symbol "VNR." Our Series A, Series B and Series C Cumulative Preferred units are also listed on the NASDAQ under the symbols "VNRAP", "VNRBP" and "VNRCP," respectively.

1. Summary of Significant Accounting Policies

The accompanying consolidated financial statements are unaudited and were prepared from our records. We derived the Consolidated Balance Sheet as of December 31, 2014, from the audited financial statements contained in our 2014 Annual Report. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles in the United States ("GAAP"). You should read this Quarterly Report on Form 10-Q along with our 2014 Annual Report, which contains a summary of our significant accounting policies and other disclosures. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Information for interim periods may not be indicative of our operating results for the entire year.

As of March 31, 2015, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2014 Annual Report.

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of March 31, 2015 and December 31, 2014 and for the three months ended March 31, 2015 and 2014 include our accounts and those of our subsidiaries. We present our financial statements in accordance with GAAP. All intercompany transactions and balances have been eliminated upon consolidation. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or members' equity.

(b) Oil and Natural Gas Properties:

The full cost method of accounting is used to account for oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil, natural gas and NGLs reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and subject to ceiling test limitations as discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs on a quarterly basis. Specifically, costs are transferred to the amortizable base when properties are determined to have proved reserves. In addition, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory wells are determined to be unsuccessful. Additionally, the amortizable base includes estimated future development costs, dismantlement, restoration and abandonment costs net of estimated salvage values.

Capitalized costs are limited to a ceiling based on the present value of future net revenues, computed using the 12-month unweighted average of first-day-of-the-month historical price, the “12-month average price” discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write-down capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write-downs are included in the Consolidated Statements of Operations as an impairment charge. No ceiling test impairment was required during the three months ended March 31, 2014.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the three months ended March 31, 2015 of $132.6 million as a result of a decline in oil and natural gas prices at the measurement date, March 31, 2015. The first quarter 2015 impairment was calculated based on the 12-month average price of $3.91 per MMBtu for natural gas and $82.62 per barrel of crude oil.

When we sell or convey interests in oil and natural gas properties, we reduce oil and natural gas reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of oil and natural gas properties unless those sales would significantly alter the relationship between capitalized costs and proved reserves. Sales proceeds on insignificant sales are treated as an adjustment to the cost of the properties.

(c) New Pronouncement Issued But Not Yet Adopted:

In April 2015, the FASB issued Accounting Standards Update (“ASU”) No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs (“ASU No. 2015-03”), which requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 is to be applied retrospectively and is effective for periods beginning after December 15, 2015. The Company will adopt ASU No. 2015-03 by the date required, which will affect the presentation of debt issuance costs in the balance sheet but will not have any impact on the Company’s results of operations or financial position.

(d) Use of Estimates:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in impairment tests of oil and natural gas properties and goodwill, the acquisition of oil and natural gas properties, the fair value of derivative contracts and asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

2. Acquisitions

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC Topic 805, “Business Combinations” (“ASC Topic 805”). An acquisition may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. Any such gain or any loss resulting from the impairment of goodwill is recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of the properties acquired in our acquisitions have been included in the consolidated financial statements since the closing dates of the acquisitions.

2014 Acquisitions

Pinedale Acquisition

On January 31, 2014, we completed the acquisition of natural gas and oil properties in the Pinedale and Jonah fields of Southwestern Wyoming for approximately $555.6 million in cash with an effective date of October 1, 2013. We refer to this acquisition as the “Pinedale Acquisition.” The purchase price was funded with borrowings under our Reserve-Based Credit Facility (as defined below). In accordance with ASC Topic 805, this acquisition resulted in a gain of $32.1 million, as reflected in the table below, primarily due to the increase in natural gas prices between the date the purchase and sale agreement was entered into and the closing date.

| Fair value of assets and liabilities acquired | (in thousands) | |
|---|---|---|
| Oil and natural gas properties | $ 600,123 | |
| Inventory | 244 | |
| Asset retirement obligations | (12,404 | ) |
| Imbalance liabilities | (171 | ) |
| Other | (125 | ) |
| Total fair value of assets and liabilities acquired | 587,667 | |
| Fair value of consideration transferred | 555,553 | |
| Gain on acquisition | $ 32,114 | |

Piceance Acquisition

On September 30, 2014, we completed the acquisition of natural gas, oil and NGLs assets in the Piceance Basin in Colorado for approximately $496.4 million in cash with an effective date of July 1, 2014. We refer to this acquisition as the “Piceance Acquisition.” The purchase price was funded with borrowings under our Reserve-Based Credit Facility. In accordance with ASC Topic 805, this acquisition resulted in goodwill of $0.4 million, as reflected in the table below, which was immediately impaired and recorded as a loss in current period earnings. The loss resulted primarily from the changes in natural gas prices between the date the purchase and sale agreement was entered into and the closing date, which were used to value the reserves acquired.

| Fair value of assets and liabilities acquired | (in thousands) | |
|---|---|---|
| Oil and natural gas properties | $ 523,537 | |
| Asset retirement obligations | (19,452 | ) |
| Production and ad valorem taxes payable | (7,552 | ) |
| Suspense liabilities | (445 | ) |
| Other | (124 | ) |
| Total fair value of assets and liabilities acquired | 495,964 | |
| Fair value of consideration transferred | 496,391 | |
| Loss on acquisition | $ (427 | ) |

Other Acquisitions

On May 1, 2014, we completed an asset exchange transaction with Marathon Oil Company in which we acquired natural gas and NGLs properties in the Wamsutter natural gas field in Wyoming in exchange for 75% of our working interests in the Gooseberry Field properties in Wyoming. The total consideration for this transaction was the mutual exchange and assignment of interests in the properties and cash consideration of $6.8 million paid to Marathon Oil Company. The cash consideration was funded with borrowings under our existing Reserve-Based Credit Facility. The effective date of the acquisition is January 1, 2014.

On August 29, 2014, we completed the acquisition of certain natural gas, oil and NGLs properties located in North Louisiana and East Texas for an adjusted purchase price of $265.1 million. We refer to this acquisition as the "Gulf Coast Acquisition." The purchase price was funded with borrowings under our existing Reserve-Based Credit Facility. The effective date of the acquisition is June 1, 2014.

During the year ended December 31, 2014, we completed other smaller acquisitions of certain natural gas, oil and NGLs properties located in the Permian Basin and Powder River Basin in Wyoming for an aggregate purchase price of $17.7 million which was funded with borrowings under our existing Reserve-Based Credit Facility.

Pro Forma Operating Results

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the three months ended March 31, 2014 to show the effect on our consolidated results of operations as if our acquisitions completed in 2014 had occurred on January 1, 2013.

The pro forma results reflect the results of combining our statement of operations with the results of operations from the oil and natural gas properties acquired during 2014, adjusted for (i) the assumption of asset retirement obligations and accretion expense for the properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired, and (iii) interest expense on additional borrowings necessary to finance the acquisitions. The net gain on acquisition of oil and natural gas properties was excluded from the pro forma results for the three months ended March 31, 2014. The pro forma information is based upon these assumptions and is not necessarily indicative of future results of operations:

| | Pro forma (in thousands, except per unit data) Three Months Ended March 31, 2014 |
|---|---|
| Total revenues | $ 166,486 |
| Net income attributable to Common and Class B unitholders | $ 9,741 |
| Net income per Common and Class B unit, Basic and Diluted | $ 0.12 |

Post-Acquisition Operating Results

The amount of revenues and excess of revenues over direct operating expenses included in the accompanying Consolidated Statements of Operations for all of our acquisitions are shown in the table that follows. Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in thousands) | |
| Pinedale Acquisition | | |
| Revenues | $23,733 | $29,641 |
| Excess of revenues over direct operating expenses | $16,578 | $23,091 |
| Piceance Acquisition | | |
| Revenues | $11,773 | $— |
| Excess of revenues over direct operating expenses | $6,073 | $— |
| All other acquisitions | | |
| Revenues | $9,393 | $— |
| Excess of revenues over direct operating expenses | $4,939 | $— |

3. Long-Term Debt

Our financing arrangements consisted of the following as of the date indicated:

| Description | Interest Rate | Maturity Date | Amount Outstanding March 31, 2015 | December 31, 2014 |
|---|---|---|---|---|
| | | | (in thousands) | |
| Senior Secured Reserve-Based Credit Facility | Variable (1) | April 16, 2018 | $1,330,000 | $1,360,000 |
| Senior Notes | 7.875% (2) | April 1, 2020 | 550,000 | 550,000 |
| Lease Financing Obligation | 4.16% | August 10, 2020 (3) | $27,923 | 28,986 |
| | | | $1,907,923 | $1,938,986 |
| Less: | | | | |
| Unamortized discount on Senior Notes | | | (1,782) | (1,852) |
| Current portion of Lease Financing Obligation | | | (4,363) | (4,318) |
| Total long-term debt | | | $1,901,778 | $1,932,816 |

(1) Variable interest rate was 2.18% and 2.17% at March 31, 2015 and December 31, 2014, respectively.
(2) Effective interest rate was 8.0%.
(3) The Lease Financing Obligations expire on August 10, 2020, except for certain obligations which expire on July 10, 2021.

Senior Secured Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the "Credit Agreement") provides a maximum credit facility of $3.5 billion and an initial borrowing base of $2.0 billion (the "Reserve-Based Credit Facility"). As of March 31, 2015, there were approximately $1.33 billion of outstanding borrowings and $665.5 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $4.5 million reduction in availability for letters of credit (discussed below).

Interest rates under the Reserve-Based Credit Facility are based on Eurodollar (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. At March 31, 2015, the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

11

Borrowing Base Utilization Grid

| Borrowing Base Utilization Percentage | <25% | | >25% <50% | | >50% <75% | | >75% <90% | | >90% | |
|---|---|---|---|---|---|---|---|---|---|---|
| Eurodollar Loans Margin | 1.50 | % | 1.75 | % | 2.00 | % | 2.25 | % | 2.50 | % |
| ABR Loans Margin | 0.50 | % | 0.75 | % | 1.00 | % | 1.25 | % | 1.50 | % |
| Commitment Fee Rate | 0.50 | % | 0.50 | % | 0.375 | % | 0.375 | % | 0.375 | % |
| Letter of Credit Fee | 0.50 | % | 0.75 | % | 1.00 | % | 1.25 | % | 1.50 | % |

Our Reserve-Based Credit Facility contains a number of customary covenants that require us to maintain certain financial ratios. Specifically, as of the end of each fiscal quarter, we may not permit the following: (a) our current ratio to be less than 1.0 to 1.0 and (b) our total leverage ratio to be more than 4.0 to 1.0. In addition, we are subject to various other covenants including, but not limited to, those limiting our ability to incur indebtedness, enter into commodity and interest rate derivatives, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of our assets.

At March 31, 2015, we were in compliance with all of our debt covenants. Based on projected market conditions and lower commodity prices, we currently expect that we will not be in compliance with our total leverage ratio covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our leverage ratio covenant during our next scheduled borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted adjusted EBITDA due to the lower commodity price environment. We expect our borrowing base to be reduced as a result of this redetermination. Absent the success of amending our leverage ratio, a resultant breach of the covenants under our Reserve-Based Credit Facility would cause a default under the reserve-based credit agreement and the lenders would be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. This, in turn, would cause a default under the senior notes due in 2020 and permit the holders of those notes to accelerate their maturity. We are currently in the process of our semi-annual borrowing base redetermination and anticipate its completion in May 2015.

Letters of Credit

At March 31, 2015, we have unused irrevocable standby letters of credit of approximately $4.5 million. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit is provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

We have $550.0 million outstanding in aggregate principal amount of 7.875% senior notes due 2020 (the “Senior Notes”). The issuers of the Senior Notes are VNR and our 100% owned finance subsidiary, VNRF. VNR has no independent assets or operations. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to certain customary release provisions, including: (i) upon the sale or other disposition of all or substantially all of the subsidiary’s properties or assets; (ii) upon the sale or other disposition of our equity interests in the subsidiary; (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture; (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture; (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities; or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor’s Rating Services and Moody’s Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At March 31, 2015, based on the most restrictive covenants of the Indenture, the Company’s cash balance and the borrowings available under the Reserve-Based Credit Facility, approximately $74.5 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.93750% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter. We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

Lease Financing Obligations

On October 24, 2014, in connection with our Piceance Acquisition, we entered into an assignment and assumption agreement, whereby we acquired compressors and related facilities and assumed the related financing obligations (the "Lease Financing Obligations"). Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option whereby the Company may purchase the equipment for $16.0 million on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts primarily with counterparties that are also lenders under our Reserve-Based Credit Facility to hedge price risk associated with a portion of our oil, natural gas and NGLs production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Pricing for these derivative contracts is based on certain market indexes and prices at our primary sales points.

We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our Reserve-Based Credit Facility, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

During the first quarter of 2015, we have taken steps to restructure our hedge portfolio to limit further downside and volatility due to the current commodity price environment. Specifically, we have converted a significant portion of our three-way collars in 2015 to fixed-price swaps or lowered the pricing on existing short puts.

At March 31, 2015, the Company had open commodity derivative contracts covering our anticipated future production as follows:

Fixed-Price Swaps

| | Gas | | Oil | | NGLs |
|---|---|---|---|---|---|
| Contract Period | MMBtu | Weighted Average | Bbls | Weighted Average | Bbls |

| | | Fixed Price | | WTI Price | | Weighted Average Fixed Price |
|---|---|---|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 66,137,500 | $ 4.26 | 1,846,750 | $ 73.07 | 185,625 | $46.34 |
| January 1, 2016 – December 31, 2016 | 55,083,000 | $ 4.47 | 146,400 | $ 89.98 | — | $— |
| January 1, 2017 – December 31, 2017 | 24,027,000 | $ 4.35 | — | $ — | — | $— |

13

Call Options Sold

| | Gas | | Oil | |
|---|---|---|---|---|
| Contract Period | MMBtu | Weighted Average Fixed Price | Bbls | Weighted Average Fixed Price |
| April 1, 2015 – December 31, 2015 | — | $ — | 55,000 | $ 105.00 |
| January 1, 2016 – December 31, 2016 | 9,150,000 | $ 4.25 | 622,200 | $ 125.00 |
| January 1, 2017 – December 31, 2017 | 9,125,000 | $ 4.50 | 365,000 | $ 95.00 |

Basis Swaps

| | Gas | | |
|---|---|---|---|
| Contract Period | MMBtu | Weighted Avg. Basis Differential ($/MMBtu) | Pricing Index |
| April 1, 2015 – December 31, 2015 | 22,000,000 | $(0.28) | Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential |
| January 1, 2016 – December 31, 2016 | 18,300,000 | $(0.24) | Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential |
| January 1, 2017 – December 31, 2017 | 10,950,000 | $(0.22) | Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential |

| | Oil | | |
|---|---|---|---|
| Contract Period | Bbls | Weighted Avg. Basis Differential ($/Bbl) | Pricing Index |
| April 1, 2015 – December 31, 2015 | 385,000 | $(1.68) | WTI Midland and WTI Cushing Basis Differential |
| April 1, 2015 – December 31, 2015 | 110,000 | $(2.33) | West Texas Sour and WTI Cushing Basis Differential |
| April 1, 2015 – December 31, 2015 | 550,000 | $(14.50) | WTI and West Canadian Select Basis Differential |

Three-Way Collars

| | Gas | | | |
|---|---|---|---|---|
| Contract Period | MMBtu | Floor | Ceiling | Put Sold |
| January 1, 2016 – December 31, 2016 | 12,810,000 | $3.95 | $4.25 | $3.00 |
| January 1, 2017 – December 31, 2017 | 16,425,000 | $3.92 | $4.23 | $3.37 |

| | Oil | | | |
|---|---|---|---|---|
| Contract Period | Bbls | Floor | Ceiling | Put Sold |
| April 1, 2015 – December 31, 2015 | 160,750 | $90.00 | $97.26 | $76.43 |
| January 1, 2016 – December 31, 2016 | 1,061,400 | $90.00 | $96.18 | $73.62 |

Put Options Sold

| Contract Period | Gas MMBtu | Put Sold ($/MMBtu) | Oil Bbls | Put Sold ($/Bbl) |
|---|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 19,937,500 | $2.99 | 476,000 | $72.11 |
| January 1, 2016 – December 31, 2016 | 1,830,000 | $3.00 | 146,400 | $75.00 |
| January 1, 2017 – December 31, 2017 | 1,825,000 | $3.50 | 73,000 | $75.00 |

Range Bonus Accumulators

| Contract Period | Gas MMBtu | Bonus | Range Ceiling | Range Floor |
|---|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 1,100,000 | $0.16 | $4.00 | $2.50 |

| Contract Period | Oil Bbls | Bonus | Range Ceiling | Range Floor |
|---|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 137,500 | $4.00 | $100.00 | $75.00 |
| January 1, 2016 – December 31, 2016 | 183,000 | $4.00 | $100.00 | $75.00 |

Collars

| Contract Period | Oil Bbls | Floor Price ($/Bbl) | Ceiling Price ($/Bbl) |
|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 274,500 | $50.00 | $56.85 |

Call Spreads

| Contract Period | Oil Bbls | Call Price ($/Bbl) | Short Call Price ($/Bbl) |
|---|---|---|---|
| April 1, 2015 – December 31, 2015 | 947,600 | $70.00 | $85.00 |

Puts

| Contract Period | Oil Bbls | Put Price ($/Bbl) |
|---|---|---|
| January 1, 2016 – December 31, 2016 | 366,000 | $60.00 |

Interest Rate Swaps

At March 31, 2015, we had open interest rate derivative contracts as follows (in thousands):

| Period | Notional Amount | Fixed LIBOR Rates |
|---|---|---|
| April 1, 2015 to December 10, 2016 | $ 20,000 | 2.17 % |
| April 1, 2015 to October 31, 2016 | $ 40,000 | 1.65 % |
| April 1, 2015 to August 5, 2015 (1) | $ 30,000 | 2.25 % |
| April 1, 2015 to August 6, 2016 | $ 25,000 | 1.80 % |
| April 1, 2015 to October 31, 2016 | $ 20,000 | 1.78 % |
| April 1, 2015 to September 23, 2016 | $ 75,000 | 1.15 % |
| April 1, 2015 to March 7, 2016 | $ 75,000 | 1.08 % |
| April 1, 2015 to September 7, 2016 | $ 25,000 | 1.25 % |
| April 1, 2015 to December 10, 2015 (2) | $ 50,000 | 0.21 % |
| Total | $ 360,000 | |

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018 at 2.25%.
(2) The counterparty has the option to require Vanguard to pay a fixed rate of 0.91% from December 10, 2015 to December 10, 2017.

Balance Sheet Presentation

Our commodity derivatives and interest rate swap derivatives are presented on a net basis in “derivative assets” and “derivative liabilities” on the Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Consolidated Balance Sheets for the periods indicated (in thousands):

| | March 31, 2015 | | |
|---|---|---|---|
| Offsetting Derivative Assets: | Gross Amounts of Recognized Assets | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts Presented in the Consolidated Balance Sheets |
| Commodity price derivative contracts | $309,531 | $(59,676) | $249,855 |
| Total derivative instruments | $309,531 | $(59,676) | $249,855 |
| Offsetting Derivative Liabilities: | Gross Amounts of Recognized Liabilities | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts Presented in the Consolidated Balance Sheets |
| Commodity price derivative contracts | $(59,688) | $59,676 | $(12) |
| Interest rate derivative contracts | (4,881) | — | (4,881) |
| Total derivative instruments | $(64,569) | $59,676 | $(4,893) |

| | December 31, 2014 | | |
|---|---|---|---|
| Offsetting Derivative Assets: | Gross Amounts of Recognized Assets | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts Presented in the Consolidated Balance Sheets |
| Commodity price derivative contracts | $289,018 | $(63,321) | $225,697 |
| Total derivative instruments | $289,018 | $(63,321) | $225,697 |

| Offsetting Derivative Liabilities: | Gross Amounts of Recognized Liabilities | Gross Amounts Offset in the Consolidated Balance Sheets | Net Amounts Presented in the Consolidated Balance Sheets |
|---|---|---|---|
| Commodity price derivative contracts | $(63,615) | $63,321 | $(294) |
| Interest rate derivative contracts | (4,669) | — | (4,669) |
| Total derivative instruments | $(68,284) | $63,321 | $(4,963) |

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Our counterparties are participants in our Reserve-Based Credit Facility (see Note 3. Long-Term Debt for further discussion), which is secured by our oil and natural gas properties; therefore, we are not required to post any collateral. The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $309.5 million at March 31, 2015. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated as of March 31, 2015. We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments primarily with counterparties that are also lenders in our Reserve-Based Credit Facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis.

Changes in fair value of our commodity and interest rate derivatives for the three months ended March 31, 2015 and the year ended December 31, 2014 are as follows:

| | Three Months Ended March 31, 2015 | Year Ended December 31, 2014 |
|---|---|---|
| | (in thousands) | |
| Derivative asset at beginning of period, net | $220,734 | $66,711 |
| Purchases | | |
| Fair value of derivatives acquired | 35,644 | (1,344) |
| Net gains on commodity and interest rate derivative contracts | 57,830 | 161,519 |
| Settlements | | |
| Cash settlements received on matured commodity derivative contracts | (38,291) | (10,187) |
| Cash settlements paid on matured interest rate derivative contracts | 990 | 4,035 |
| Termination of derivative contracts | (31,945) | — |
| Derivative asset at end of period, net | $244,962 | $220,734 |

5. Fair Value Measurements

We estimate the fair values of financial and non-financial assets and liabilities under ASC Topic 820 “Fair Value Measurements and Disclosures” (“ASC Topic 820”). ASC Topic 820 provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, recognition of asset retirement obligations and to long-lived assets written down to fair value when they are impaired. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on SEC rules. ASC Topic 820 applies to assets and liabilities carried at fair value on the Consolidated Balance Sheets, as well as to supplemental information about the fair values of financial instruments not carried at fair value.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis, which includes our commodity and interest rate derivatives contracts, and on a nonrecurring basis, which includes goodwill, acquisitions of oil and natural gas properties and other intangible assets. ASC Topic 820 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction.

ASC Topic 820 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the “levels” described below. The hierarchy is based on the reliability of the inputs used in estimating fair value and requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The framework for fair value measurement assumes that transparent “observable” (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as the lowest) of significant input to the fair value estimation process.

The standard describes three levels of inputs that may be used to measure fair value:

| | |
|---|---|
| Level 1 | Quoted prices for identical instruments in active markets. |
| Level 2 | Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. |

| | |
|---|---|
| Level 3 | Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used. |

As required by ASC Topic 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Financing arrangements. The carrying amounts of our bank borrowings outstanding approximate fair value because our current borrowing rates do not materially differ from market rates for similar bank borrowings. We consider this fair value estimate as a Level 2 input. As of March 31, 2015, the fair value of our Senior Notes was estimated to be $509.3 million. We consider the inputs to the valuation of our Senior Notes to be Level 1 as fair value was estimated based on prices quoted from a third-party financial institution.

Derivative instruments. Our commodity derivative instruments consist of fixed-price swaps, basis swaps, call options sold, put options sold, call spreads, call options, put options, three-way collars and range bonus accumulators. We account for our commodity derivatives and interest rate derivatives at fair value on a recurring basis. We estimate the fair values of the fixed-price swaps and basis-swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option value of the contract floors, ceilings and three-way collars using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. We consider the fair value estimate for these derivative instruments as a Level 2 input. We estimate the value of the range bonus accumulators using an option pricing model for both Asian Range Digital options and Asian Put options that takes into account market volatility, market prices and contract parameters. Range bonus accumulators are complex in structure requiring sophisticated valuation methods and greater subjectivity. As such, range bonus accumulators valuation may include inputs and assumptions that are less observable or require greater estimation, thereby resulting in valuations with less certainty. We consider the fair value estimate for range bonus accumulators as a Level 3 input.

Inputs to the pricing models include publicly available prices and forward price curves generated from a compilation of data gathered from third parties. Management validates the data provided by third parties by understanding the pricing models used, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to our commodity derivatives and interest rate derivatives.

Financial assets and financial liabilities measured at fair value on a recurring basis are summarized below (in thousands):

| | March 31, 2015 | |
|---|---|---|
| | Fair Value Measurements Using | Assets/Liabilities |

| | Level 1 | Level 2 | Level 3 | at Fair value |
|---|---|---|---|---|
| Assets: | | | | |
| Commodity price derivative contracts | $— | $256,190 | $(6,335) | $249,855 |
| Total derivative instruments | $— | $256,190 | $(6,335) | $249,855 |
| Liabilities: | | | | |
| Commodity price derivative contracts | $— | $(12) | $— | $(12) |
| Interest rate derivative contracts | — | (4,881) | — | (4,881) |
| Total derivative instruments | $— | $(4,893) | $— | $(4,893) |

| | December 31, 2014 | | | |
|---|---|---|---|---|
| | Fair Value Measurements Using | | | Assets/Liabilities |
| | Level 1 | Level 2 | Level 3 | at Fair value |
| Assets: | | | | |
| Commodity price derivative contracts | $— | $232,167 | $(6,470) | $225,697 |
| Total derivative instruments | $— | $232,167 | $(6,470) | $225,697 |
| Liabilities: | | | | |
| Commodity price derivative contracts | $— | $(294) | $— | $(294) |
| Interest rate derivative contracts | — | (4,669) | — | (4,669) |
| Total derivative instruments | $— | $(4,963) | $— | $(4,963) |

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 (unobservable inputs) in the fair value hierarchy:

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (in thousands) | |
| Unobservable inputs, beginning of period | $(6,470) | $566 |
| Total gains (losses) | 1,287 | (957) |
| Settlements | (1,152) | 36 |
| Unobservable inputs, end of period | $(6,335) | $(355) |
| Change in fair value included in earnings related to derivatives still held as of March 31, | $(804) | $(670) |

During periods of market disruption, including periods of volatile oil and natural gas prices, there may be certain asset classes that were in active markets with observable data that become illiquid due to changes in the financial environment. In such cases, more derivative instruments, other than the range bonus accumulators, may fall to Level 3 and thus require more subjectivity and management judgment. Further, rapidly changing commodity and unprecedented credit and equity market conditions could materially impact the valuation of derivative instruments as reported within our consolidated financial statements and the period-to-period changes in value could vary significantly. Decreases in value may have a material adverse effect on our results of operations or financial condition.

We apply the provisions of ASC Topic 350 “Intangibles-Goodwill and Other.” Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. Goodwill is assessed for impairment annually on October 1 or whenever indicators of impairment exist. The goodwill test is performed at the reporting unit level, which represents our oil and natural gas operations in the United States. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. We utilize a market approach to determine the fair value of our reporting unit. While no goodwill impairment was recognized at March 31, 2015, any further significant decline in prices of oil and natural gas or significant negative reserve adjustments could change our estimate of the fair value of the reporting unit and could result in an impairment charge.

Our nonfinancial assets and liabilities that are initially measured at fair value are comprised primarily of assets acquired in business combinations and asset retirement costs and obligations. These assets and liabilities are recorded at fair value when acquired/incurred but not re-measured at fair value in subsequent periods. We classify such initial measurements as Level 3 since certain significant unobservable inputs are utilized in their determination. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 6, in accordance with ASC Topic 410-20 "Asset Retirement Obligations." During the three months ended March 31, 2015 and year ended December 31, 2014, in connection with new wells drilled and wells acquired during the period, we incurred and recorded asset retirement obligations totaling $0.4 million and $52.8 million, respectively, at fair value. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate of 4.6%; and (4) the average inflation factor (2.3%). These inputs require significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

6. Asset Retirement Obligations

The asset retirement obligations as of March 31, 2015 and December 31, 2014 reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for the three months ended March 31, 2015 and year ended December 31, 2014 were as follows (in thousands):

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| Asset retirement obligations, beginning of period | $149,062 | $87,967 |
| Liabilities added during the current period | 360 | 52,829 |
| Accretion expense | 1,835 | 5,889 |
| Retirements | (280) | (450) |
| Disposition of properties | — | (1,291) |
| Change in estimate | — | 4,118 |
| Asset retirement obligation, end of period | 150,977 | 149,062 |
| Less: current obligations | (2,386) | (2,386) |
| Long-term asset retirement obligation, end of period | $148,591 | $146,676 |

7. Commitments and Contingencies

Transportation Demand Charges

As of March 31, 2015, we have contracts that provide firm transportation capacity on pipeline systems. The remaining terms on these contracts range from one to five years and require us to pay transportation demand charges regardless of the amount of pipeline capacity we utilize.

The values in the table below represent gross future minimum transportation demand charges we are obligated to pay as of March 31, 2015. However, our financial statements will reflect our proportionate share of the charges based on our working interest and net revenue interest, which will vary from property to property.

| | March 31, 2015 (in thousands) |
|---|---|
| April 1, 2015 - December 31, 2015 | $13,046 |
| 2016 | 14,508 |
| 2017 | 12,362 |
| 2018 | 11,696 |
| 2019 | 9,661 |

| | |
|---|---|
| Thereafter | 410 |
| Total | $61,683 |

20

Legal Proceedings

We are defendants in legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow. We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

8. Members' Equity and Net Income per Common and Class B Unit

Cumulative Preferred Units

The following table summarizes the Company's Cumulative Preferred units outstanding at March 31, 2015 and December 31, 2014:

| | | | | March 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|---|---|---|
| | Earliest Redemption Date | Liquidation Preference Per Share | Distribution Rate | Units Outstanding | Carrying Value (in thousands) | Units Outstanding | Carrying Value (in thousands) |
| Series A | June 15, 2023 | $25.00 | 7.875% | 2,581,873 | $62,200 | 2,581,873 | $62,200 |
| Series B | April 15, 2024 | $25.00 | 7.625% | 7,000,000 | $169,265 | 7,000,000 | $169,265 |
| Series C | October 15, 2024 | $25.00 | 7.75% | 4,300,000 | $103,979 | 4,300,000 | $103,979 |
| Total Cumulative Preferred Units | | | | 13,881,873 | $335,444 | 13,881,873 | $335,444 |

The Cumulative Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units, at our option, commencing on the redemptions dates as stated above. The Cumulative Preferred Units can be redeemed, in whole or in part, out of amounts legally available therefore, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared.

Upon the occurrence of a change of control, each holder of Cumulative Preferred Units will have the right to convert some or all of the their Cumulative Preferred Units into our common units unless prior to the change of control, we provide notice of our election to redeem the Cumulative Preferred Units or we exercise any of our redemption rights relating to the units prior to the change of control conversion date as set by our board of directors. Also upon the occurrence of a change of control we may, at our option and subject to certain restrictions, redeem the Cumulative Preferred Units by paying $25.00 per unit, plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared.

Holders of the Cumulative Preferred Units will have no voting rights except for limited voting rights if we fail to pay dividends for eighteen or more monthly periods (whether or not consecutive) and in certain other limited circumstances or as required by law. The Cumulative Preferred Units have a liquidation preference which is equal to the redemption price described above.

Common and Class B Units

The common units represent limited liability company interests. Holders of Class B units have substantially the same rights and obligations as the holders of common units.

The following is a summary of the changes in our common units issued during the three months ended March 31, 2015 and the year ended December 31, 2014 (in thousands):

| | March 31, 2015 | December 31, 2014 |
|---|---|---|
| Beginning of period | 83,452 | 78,337 |
| Issuance of Common units for cash | 849 | 4,864 |
| Repurchase of units under the Common unit buyback program | (157) | (135) |
| Reissuance of Common units for restricted unit grants | 292 | — |
| Unit-based compensation | 334 | 386 |
| End of period | 84,770 | 83,452 |

There was no change in issued and outstanding Class B units during the three months ended March 31, 2015 or the year ended December 31, 2014.

Net Income per Common and Class B Unit

Basic net income per common and Class B unit is computed in accordance with ASC Topic 260 "Earnings Per Share" ("ASC Topic 260") by dividing net income attributable to common and Class B unitholders by the weighted average number of units outstanding during the period. Diluted net income per common and Class B unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic net income per unit. The Cumulative Preferred Units have no participation rights and accordingly are excluded from the computation of basic net income per unit.

The net income (loss) attributable to common and Class B unitholders and the weighted average units for calculating basic and diluted net income (loss) per common and Class B unit were as follows (in thousands, except per unit data):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| Net income (loss) attributable to common and Class B unitholders | $(125,520) | $13,159 |
| Weighted average number of common and Class B units outstanding - basic | 84,164 | 79,606 |
| Effect of dilutive securities: | | |
| Phantom units [(a)] | — | 286 |
| Weighted average number of common and Class B units outstanding - diluted | 84,164 | 79,892 |
| Net income (loss) per common and Class B unit | | |
| Basic | $(1.49) | $0.17 |
| Diluted | $(1.49) | $0.16 |

(a) For the three months ended March 31, 2015, 202,407 phantom units were excluded from the calculation of diluted earnings per unit due to their antidilutive effect as we were in a loss position.

Distributions Declared

The Cumulative Preferred Units rank senior to our common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up. Distributions on the Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by our board of directors. We will pay cumulative distributions in cash on the Preferred Units on a monthly basis at a monthly rate of 7.875% per annum of the liquidation preference of $25.00 per Series A Cumulative Preferred Unit, a monthly rate of 7.625% per annum of the liquidation preference of $25.00 per Series B Cumulative Preferred Unit and a monthly rate of 7.75% per annum of the liquidation preference of $25.00 per Series C Cumulative Preferred Unit.

The following table shows the distribution amount, declared date, record date and payment date of the cash distributions we paid on each of our common and Class B units for each period presented. Future distributions are at the discretion of our board of directors and will depend on business conditions, earnings, our cash requirements and other relevant factors.

On April 15, 2015, our board of directors declared a cash distribution on the Cumulative Preferred Units and common and Class B units attributable to the month of March 2015. See Note 11. Subsequent Events for further discussion.

| Distribution | Cash Distributions Per Unit | Declared Date | Record Date | Payment Date |
|---|---|---|---|---|
| 2015 | | | | |
| February | $0.1175 | March 18, 2015 | April 1, 2015 | April 14, 2015 |
| January | $0.1175 | February 17, 2015 | March 2, 2015 | March 17, 2015 |
| 2014 | | | | |
| Fourth Quarter | | | | |
| December | $0.2100 | January 22, 2015 | February 2, 2015 | February 13, 2015 |
| November | $0.2100 | December 16, 2014 | January 2, 2015 | January 14, 2015 |
| October | $0.2100 | November 20, 2014 | December 1, 2014 | December 15, 2014 |
| Third Quarter | | | | |
| September | $0.2100 | October 20, 2014 | November 3, 2014 | November 14, 2014 |
| August | $0.2100 | September 19, 2014 | October 1, 2014 | October 15, 2014 |
| July | $0.2100 | August 19, 2014 | September 2, 2014 | September 12, 2014 |
| Second Quarter | | | | |
| June | $0.2100 | July 16, 2014 | August 1, 2014 | August 14, 2014 |
| May | $0.2100 | June 24, 2014 | July 1, 2014 | July 15, 2014 |
| April | $0.2100 | May 20, 2014 | June 2, 2014 | June 13, 2014 |
| First Quarter | | | | |
| March | $0.2100 | April 17, 2014 | May 1, 2014 | May 15, 2014 |
| February | $0.2100 | March 17, 2014 | April 1, 2014 | April 14, 2014 |
| January | $0.2075 | February 20, 2014 | March 3, 2014 | March 17, 2014 |
| 2013 | | | | |
| Fourth Quarter | | | | |
| December | $0.2075 | January 16, 2014 | February 3, 2014 | February 14, 2014 |

9. Unit-Based Compensation

Long-Term Incentive Plan

The Vanguard Natural Resources, LLC Long-Term Incentive Plan (the "VNR LTIP") was adopted by the Board of Directors of the Company to compensate employees and nonemployee directors of the Company and its affiliates who perform services for the Company under the terms of the plan. The VNR LTIP is administered by the compensation committee of the board of directors (the "Compensation Committee") and permits the grant of unrestricted units, restricted units, phantom units, unit options and unit appreciation rights.

Restricted and Phantom Units

A restricted unit is a unit grant that vests over a period of time and that during such time is subject to forfeiture. A phantom unit grant represents the equivalent of one common unit of the Company. The phantom units, once vested, are settled through the delivery of a number of common units equal to the number of such vested units, or an amount of cash equal to the fair market value of such common units on the vesting date to be paid in a single lump sum payment, as determined by the compensation committee in its discretion. The Compensation Committee may grant tandem distribution equivalent rights ("DERs") with respect to the phantom units that entitle the holder to receive the value of any distributions made by us on our units while the phantom units are outstanding.

The fair value of restricted unit and phantom unit awards is measured based on the fair market value of the Company units on the date of grant. The values of restricted unit grants and phantom unit grants that are required to be settled in units are recognized as expense over the vesting period of the grants with a corresponding charge to members' equity. When the Company has the option to settle the phantom unit grants by issuing Company units or through cash settlement, the Company recognizes the value of those grants utilizing the liability method as defined under ASC Topic 718 based on the Company's historical practice of settling phantom units predominantly in cash. The fair value of liability awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period.

Executive Employment Agreements

In June and July 2013, we and VNRH entered into new amended and restated executive employment agreements (the "Amended Agreements") with each of our three executive officers, Messrs. Smith, Robert and Pence. The Amended Agreements were effective January 1, 2013 and the initial term of the Amended Agreements ends on January 1, 2016, with a subsequent twelve-month term extension automatically commencing on January 1, 2016 and each successive January 1 thereafter, provided that neither VNRH nor the executives deliver a timely non-renewal notice prior to a term expiration date.

The Amended Agreements provide for an annual base salary and eligibility to receive an annual performance-based cash bonus award. The annual bonus will be calculated based upon three Company performance components: absolute target distribution growth, adjusted EBITDA growth and relative unit performance to peer group, as well as a fourth component determined solely in the discretion of our board of directors. As of March 31, 2015, an accrued liability was recognized and compensation expense of $0.4 million was recorded for the three months ended March 31, 2015 related to these arrangements, which was classified in the selling, general and administrative expenses line item in the Consolidated Statement of Operations.

Under the Amended Agreements, the executives are also eligible to receive annual equity-based compensation awards, consisting of restricted units and/or phantom units granted under the VNR LTIP. Any restricted units and phantom units granted to executives under the Amended Agreements are subject to a three-year vesting period. One-third of the aggregate number of the units vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. Both the restricted and phantom units include a tandem grant of DERs.

Restricted Unit Grants

In January 2015, the executives were granted a total of 360,762 restricted units in accordance with the Amended Agreements. Also, during the three months ended March 31, 2015, our three independent board members were granted a total of 26,334 restricted units which will vest one year from the date of grant. The restricted units granted to the executives and our board members are accompanied by DERs.

A summary of the status of the non-vested restricted units as of March 31, 2015 is presented below:

| | Number of Non-vested Restricted Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Non-vested restricted units at December 31, 2014 | 440,047 | $28.87 |
| Granted | 387,096 | $15.05 |
| Forfeited | (1,443) | $30.01 |
| Vested | (110,056) | $29.48 |
| Non-vested restricted units at March 31, 2015 | 715,644 | $21.30 |

At March 31, 2015, there was approximately $12.6 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.8 years. Our Consolidated Statements of Operations reflect non-cash compensation of $3.5 million and $2.4 million in the selling, general and administrative expense line item for the three months ended March 31, 2015 and 2014, respectively.

Phantom Unit Grants

We did not grant any phantom units during the three months ended March 31, 2015 and 2014.

A summary of the status of the non-vested phantom units under the VNR LTIP as of March 31, 2015 is presented below:

| | Number of Non-vested Phantom Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Non-vested phantom units at December 31, 2014 | 330,446 | $28.58 |
| Forfeited | (1,493) | $28.43 |
| Vested | (30,000) | $27.63 |
| Non-vested phantom units at March 31, 2015 | 298,953 | $28.67 |

At March 31, 2015, there was approximately $8.6 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.3 years. For the three months ended March 31, 2015 and 2014, non-cash unit-based compensation expense of $0.4 million and $0.5 million, respectively, has been recognized in the selling, general and administrative expense line item in the Consolidated Statements of Operations.

10. Shelf Registration Statement

We have registered an indeterminate amount of Series A Cumulative Preferred Units, Series B Cumulative Preferred Units, Series C Cumulative Preferred Units, common units, debt securities and guarantees of debt securities under our currently effective shelf registration statement filed with the SEC, as amended (the “Shelf Registration Statement”). In the future, we may issue additional debt and equity securities pursuant to a prospectus supplement to the Shelf Registration Statement.

Net proceeds, terms and pricing of each offering of securities issued under the Shelf Registration Statement are determined at the time of such offerings. The Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the Shelf Registration Statement for the purpose of issuing, from time to time, any combination of debt securities, common units or Cumulative Preferred Units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

We have entered into an equity distribution agreement with respect to the issuance and sale of our Series A Cumulative Preferred Units, Series B Cumulative Preferred Units, Series C Cumulative Preferred Units, and common units. Pursuant to the terms of the equity distribution agreement, we may sell from time to time through our sales agents, (i) our common units representing limited liability company interests having an aggregate offering price of up to $400.0 million, (ii) our Series A Cumulative Preferred Units having an aggregate offering price of up to $50.0 million, (iii) our Series B Cumulative Preferred Units having an aggregate offering price of up to $100.0 million or (iv) our Series C Cumulative Preferred Units having an aggregate offering price of up to $75.0 million. The common units and Preferred Units to be sold under the equity distribution agreement are registered under our existing Shelf Registration Statement. During the three months ended March 31, 2015, total net proceeds received under the equity distribution agreement were approximately $12.2 million, after commissions and fees, from the sale of 849,217 common units.

Subsidiary Guarantors

We and VNRF, our wholly-owned finance subsidiary, may co-issue securities pursuant to the registration statement discussed above. VNR has no independent assets or operations. Debt securities that we may offer may be guaranteed by our subsidiaries. We contemplate that if we offer debt securities, the guarantees will be full and unconditional and joint and several (subject to certain customary release provisions), and any subsidiaries of VNR that do not guarantee the securities will be minor.

11. Subsequent Events

Acquisition

On April 20, 2015, we entered into a Purchase Agreement and Plan of Merger ("Merger Agreement") with LRR Energy, L.P. ("LRR Energy" or "LRE"), pursuant to which a subsidiary of Vanguard will merge into LRR Energy and, at the same time, Vanguard will acquire LRE GP, LLC, the general partner of LRR Energy for total consideration of $251.0 million in Vanguard common units, valued as of April 20, 2015, and the assumption of LRE's net debt of $288.0 million. As a result of the transaction, LRR Energy and its general partner will become wholly owned subsidiaries of Vanguard.

Under the terms of the Merger Agreement, (i) each outstanding common unit representing a limited partner interest in LRE (a "LRE Common Unit") will be converted into the right to receive 0.55 newly issued Vanguard Common Units or, in the case of fractional Vanguard Common Units, cash (the "Merger Consideration") and (ii) Vanguard will purchase all of the outstanding limited liability company interests in the LRE GP in exchange for 12,320 newly issued Vanguard Common Units. Further, in connection with the Merger Agreement, each award of restricted LRE Common Units issued under LRE's long-term incentive plan that is subject to time-based vesting and that is outstanding and unvested immediately prior to the effective time of the Merger will become fully vested and will be deemed to be a LRE Common Unit with the right to receive the Merger Consideration.

The merger is subject to customary closing conditions, including the approval of the LRR Energy unitholders. We expect that the transaction will close in the third quarter of 2015.

Distributions

On April 15, 2015, our board of directors declared a cash distribution for our common and Class B unitholders attributable to the month of March 2015 of $0.1175 per common and Class B unit ($1.41 on an annualized basis) expected to be paid on May 15, 2015 to Vanguard unitholders of record on May 1, 2015.

Also on April 15, 2015, our board of directors declared a cash distribution for our preferred unitholders of $0.1641 per Series A Cumulative Preferred Unit, $0.15885 per Series B Cumulative Preferred Unit and $0.16146 per Series C Cumulative Preferred Unit, which will be paid on May 15, 2015 to Vanguard preferred unitholders of record on May 1, 2015.

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

The historical consolidated financial statements included in this Quarterly Report on Form 10-Q (this "Quarterly Report") reflect all of the assets, liabilities and results of operations of Vanguard Natural Resources, LLC and its Consolidated Subsidiaries. The following discussion analyzes the financial condition and results of operations of Vanguard for the three months ended March 31, 2015 and 2014. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Vanguard in conjunction with our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the "2014 Annual Report") and the historical unaudited consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Overview

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, as of March 31, 2015, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Green River Basin in Wyoming;
- the Piceance Basin in Colorado;
- the Permian Basin in West Texas and New Mexico;
- the Gulf Coast Basin in Texas, Louisiana and Mississippi;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- the Wind River Basin in Wyoming; and
- the Powder River Basin in Wyoming.

As of March 31, 2015, based on internal reserve estimates, our total estimated proved reserves were 2,029 Bcfe, of which approximately 73% were natural gas reserves, 15% were oil reserves and 12% were NGLs reserves. Of these total estimated proved reserves, approximately 69%, or 1,391 Bcfe, were classified as proved developed. Also, at March 31, 2015, we owned working interests in 9,775 gross (3,599 net) productive wells. Our operated wells accounted for approximately 54% of our total estimated proved reserves at March 31, 2015. Our average net daily production for the three months ended March 31, 2015 and the year ended December 31, 2014 was 394 MMcfe/day and 327 MMcfe/day, respectively. We have interests in approximately 870,140 gross undeveloped leasehold acres surrounding our existing wells. As of March 31, 2015, based on internal reserve estimates, approximately 31%, or 638 Bcfe, of our estimated proved reserves were attributable to our interests in undeveloped acreage.

Recent Developments

Acquisition

On April 20, 2015, we entered into a Purchase Agreement and Plan of Merger ("Merger Agreement") with LRR Energy, L.P. ("LRR Energy" or "LRE") pursuant to which a subsidiary of Vanguard will merge into LRR Energy and, at the same time, Vanguard will acquire LRE GP, LLC, the general partner of LRR Energy for total consideration of $251.0 million in Vanguard common units, valued as of April 20, 2015, and the assumption of LRE's net debt of $288.0 million. As a result of the transaction, LRR Energy and its general partner will become wholly owned subsidiaries of Vanguard.

Under the terms of the Merger Agreement, (i) each outstanding common unit representing a limited partner interest in LRE (a "LRE Common Unit") will be converted into the right to receive 0.55 newly issued Vanguard Common Units or, in the case of fractional Vanguard Common Units, cash (the "Merger Consideration") and (ii) Vanguard will purchase all of the outstanding limited liability company interests in the LRE GP in exchange for 12,320 newly issued Vanguard Common Units. Further, in connection with the Merger Agreement, each award of restricted LRE Common Units issued under LRE's long-term incentive plan that is subject to time-based vesting and that is outstanding and unvested immediately prior to the effective time of the Merger will become fully vested and will be deemed to be a LRE Common Unit with the right to receive the Merger Consideration.

The merger is subject to customary closing conditions, including the approval of the LRR Energy unitholders. We expect that the transaction will close in the third quarter of 2015.

Business Environment and Outlook

Historically, the markets for oil and natural gas have been very volatile and multiple factors during the latter half of 2014 and beginning of 2015 have caused the price of oil and natural gas to decrease dramatically. Among the factors causing such volatility are the domestic oversupply of natural gas and the foreign supply of oil, the ability of the members of OPEC and other producing countries to agree upon and maintain prices and production levels, social unrest and instability, particularly in major oil and natural gas producing regions outside the United States, and the level of consumer product demand.

Natural gas and oil prices are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the crude oil spot price per barrel during the year ended December 31, 2014 ranged from a high of $107.95 to a low of $53.45 and the NYMEX natural gas spot price per MMBtu during the year ended December 31, 2014 ranged from a high of $6.15 to a low of $2.89. As of April 27, 2015, the crude oil spot price per barrel was $55.56 and the NYMEX natural gas spot price per MMBtu was $2.50. The high to low oil price fluctuation during the year ended December 31, 2014 represents the second largest annual decline of such price in the past nine years.

The dramatic decline in commodity prices has had an impact on our unit price. During the first quarter of 2015, our common unit price fluctuated from a closing low of $12.50 on January 20, 2015 to a closing high of $18.72 on February 9, 2015. This low commodity price environment has had and will continue to have a direct impact on our revenue, cash flow from operations and adjusted EBITDA until commodity prices improve. We intend to improve our financial outlook through opportunistic hedging, profitable drilling and acquisitions of new oil and natural gas properties. We foresee significant long-term benefits in acquiring assets in this low commodity price environment.

In January 2015, we restructured our hedge portfolio to limit further downside and volatility due to the current commodity price environment. Specifically, we converted a significant portion of our three-way collars in 2015 to fixed-price swaps or lowered the pricing on existing short puts. We have implemented a hedging program for approximately 87% and 45% of our anticipated crude oil production in 2015 and 2016, respectively, with 81% in the form of fixed-price swaps for the balance of 2015. Approximately 86% and 67% of our natural gas production in 2015 and 2016, respectively, is hedged, with 100% in the form of fixed-price swaps for the balance of 2015. NGLs production is hedged using fixed-price swaps for approximately 9% of anticipated production for the balance of 2015. The impact of the merger with LRE discussed above is not included in the above percentages.

During 2015, we intend to continue to concentrate our drilling on low risk, development opportunities with the majority of drilling capital focused on high-Btu natural gas wells in the Green River Basin and Gulf Coast Basin which we believe will continue to offer attractive drilling returns even in this low commodity price environment. During the three months ended March 31, 2015, we participated in the drilling of 67 gross (8.0 net) non-operated wells and in the completion of 30 gross (3.8 net) non-operated wells.

We have reduced our cash distribution per common unit to $0.1175 for the month of January 2015, or $1.41 per unit on an annualized basis. This amount was paid on March 17, 2015, to unitholders of record at the close of business on March 2, 2015, and represents a reduction from the payment for the month of December 2014, which was $0.21 per common unit or $2.52 per unit on an annualized basis. This new distribution rate takes into consideration current commodity and financial market conditions and helps to preserve our liquidity for potential future acquisition opportunities.

At April 30, 2015, we had indebtedness under our Reserve-Based Credit facility totaling $1.33 billion with a borrowing base of $2.0 billion which provided for $665.5 million in undrawn capacity, after consideration of a $4.5 million reduction in availability for letters of credit. We are currently in the process of our semi-annual borrowing base redetermination and anticipate its completion in May 2015. Absent new acquisitions, we expect that our borrowing base will be reduced as a result of continued declines in oil and natural gas prices. The precise amount of the reduction is not known at this time but we do expect that we will have ample liquidity to manage our operations after the reduction. However, if necessary, we believe we have access to capital markets and other financing sources. Additionally, based on projected market conditions and lower commodity prices, we currently expect that we will not be in compliance with our debt to adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our credit facility regarding amending our debt to adjusted EBITDA covenant during this borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted adjusted EBITDA due to lower commodity prices.

We recorded a non-cash ceiling test impairment of oil and natural gas properties for the quarter ended March 31, 2015 of $132.6 million as a result of a decline in oil and natural gas prices at the measurement date, March 31, 2015. The first quarter 2015 impairment was calculated based on the 12-month average price of $3.91 per MMBtu for natural gas and $82.62 per barrel of crude oil.

We expect to record an additional impairment of our oil and natural gas properties during 2015 as a result of declining oil and natural gas prices. Based on the 12-month average oil, natural gas and NGLs prices through April 1, 2015 and if such prices do not change during May and June 2015, we estimate that, on a pro forma basis, we will record a ceiling test write down on our existing assets of approximately $574.5 million at June 30, 2015 and an additional write-down of $282.9 million for the remainder of the year ending December 31, 2015. However, whether the amount of any such impairments will be similar in amount to such estimates, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2015, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such impairments.

While no goodwill impairment was recognized at March 31, 2015, any further significant decline in prices of oil and natural gas or significant negative reserve adjustments could change our estimate of the fair value of the reporting unit and could result in an impairment charge.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated (in thousands):

| | Three Months Ended March 31, | |
| --- | --- | --- |
| | 2015 | 2014 [(a)] |
| Revenues: | | |
| Oil sales | $35,790 | $68,199 |
| Natural gas sales | 55,754 | 63,543 |
| NGLs sales | 7,350 | 20,998 |
| Oil, natural gas and NGLs sales | 98,894 | 152,740 |
| Net gains (losses) on commodity derivative contracts | 59,033 | (56,037) |
| Total revenues | $157,927 | $96,703 |
| Costs and expenses: | | |
| Production: | | |
| Lease operating expenses | $35,478 | $30,421 |
| Production and other taxes | 11,426 | 15,034 |
| Depreciation, depletion, amortization, and accretion | 66,840 | 43,610 |
| Impairment of oil and natural gas properties | 132,610 | — |
| Non-cash compensation | 3,961 | 2,872 |
| Other selling, general and administrative expenses | 5,090 | 5,166 |
| Total costs and expenses | $255,405 | $97,103 |
| Other income (expense): | | |
| Interest expense | $(20,189) | $(16,259) |

| | | |
|---|---|---|
| Net losses on interest rate derivative contracts | $(1,203) | $(458) |
| Gain on acquisition of oil and natural gas properties | $— | $32,114 |
| Other | $40 | $124 |

(a) During 2014, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included from the closing date of the acquisition forward.

Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

Revenues

Oil, natural gas and NGLs sales decreased $53.8 million to $98.9 million during the three months ended March 31, 2015 as compared to the same period in 2014. The key oil, natural gas and NGLs revenue measurements were as follows:

| | Three Months Ended March 31, | | Percentage Increase / (Decrease) |
|---|---|---|---|
| | 2015 | 2014[a] | |
| Average realized prices, excluding hedges: | | | |
| Oil (Price/Bbl) | $42.12 | $87.99 | (52)% |
| Natural Gas (Price/Mcf) | $2.08 | $3.96 | (47)% |
| NGLs (Price/Bbl) | $12.49 | $36.72 | (66)% |
| Average realized prices, including hedges [b]: | | | |
| Oil (Price/Bbl) | $54.71 | $84.32 | (35)% |
| Natural Gas (Price/Mcf) | $3.05 | $3.42 | (11)% |
| NGLs (Price/Bbl) | $14.76 | $35.87 | (59)% |
| Average NYMEX prices: | | | |
| Oil Price (Price/Bbl) | $48.59 | $98.69 | (51)% |
| Natural Gas Price (Price/Mcf) | $2.98 | $5.10 | (42)% |
| Total production volumes: | | | |
| Oil (MBbls) | 850 | 775 | 10% |
| Natural Gas (MMcf) | 26,860 | 16,040 | 67% |
| NGLs (MBbls) | 588 | 572 | 3% |
| Combined (MMcfe) | 35,489 | 24,121 | 47% |
| Average daily production volumes: | | | |
| Oil (Bbls/day) | 9,442 | 8,612 | 10% |
| Natural Gas (MMcf/day) | 298 | 178 | 67% |
| NGLs (Bbls/day) | 6,537 | 6,354 | 3% |
| Combined (MMcfe/day) | 394 | 268 | 47% |

(a) During 2014, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included from the closing date of the acquisition forward.

(b) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

The decrease in oil, natural gas and NGLs sales during the three months ended March 31, 2015 compared to the same period in 2014 was due primarily to the decrease in average realized oil and natural gas prices. Natural gas revenues decreased 12% from $63.5 million in the first three months of 2014 to $55.8 million in the first three months of 2015 as a result of a $1.88 per Mcf, or 47%, decrease in our average realized natural gas price, excluding hedges, offset by a 10,820 MMcf, or 67%, increase in our natural gas production due to acquisitions completed during 2014. NGLs revenues also decreased 65% during the first three months of 2015 compared to the same period in 2014 due to a $24.23 per Bbl, or 66%, decrease in our average realized NGLs price, excluding hedges. Oil revenues decreased 48%, from $68.2 million in the first three months of 2014 to $35.8 million in the first three months of 2015, as a result of a $45.87 per Bbl, or 52%, decrease in our average realized oil price, excluding hedges.

Overall, our total production for the three months ended March 31, 2015 increased by 47% on an Mcfe basis compared to the same period in 2014, which was primarily attributable to the impact from all of our acquisitions completed in 2014 wherein we realized the benefit of a full quarter of production in 2015. On an Mcfe basis, crude oil, natural gas, and NGLs accounted for 14%, 76% and 10%, respectively, of our production during the three months ended March 31, 2015 compared to 19%, 67% and 14%, respectively, of our production during the same period in 2014.

Hedging and Price Risk Management Activities

During the three months ended March 31, 2015, we recognized $59.0 million in net gains on commodity derivative contracts. Cash payments on matured commodity derivative contracts of $38.3 million were recognized during the period. Our hedging program is intended to help mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by arranging for the counterparty to pay us when commodity prices are below the hedged price and for us to pay the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because our hedges are currently not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected in our consolidated statement of operations in the net gains or losses on commodity derivative contracts line item. However, these fair value changes that are reflected in the consolidated statement of operations reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include expenses such as labor, field office, vehicle, supervision, maintenance, tools and supplies and workover expenses. Lease operating expenses increased by $5.1 million to $35.5 million for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014, of which $11.2 million related to increased lease operating expenses for oil and natural gas properties acquired during 2014. The increase was offset by a $6.1 million decrease in maintenance and repair expenses on existing wells.

Production and other taxes include severance, ad valorem and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state or county and are based on the value of our reserves. Production and other taxes decreased by $3.6 million for the three months ended March 31, 2015 as compared to the same period in 2014 primarily due to lower wellhead revenues as a result of the decrease in our average realized oil and natural gas prices. As a percentage of wellhead revenues, production, severance and ad valorem taxes were 11.6% and 9.8% for the three months ended March 31, 2015 and 2014, respectively. The percentage was higher during the three months ended March 31, 2015 primarily due to higher tax rates on properties acquired during 2014 in the state of Wyoming.

Depreciation, depletion, amortization, and accretion increased by approximately $23.2 million to $66.8 million for the three months ended March 31, 2015 from approximately $43.6 million for the three months ended March 31, 2014 primarily due to a higher depletion base associated with properties acquired during 2014.

An impairment of oil and natural gas properties of $132.6 million was recognized during the quarter ended March 31, 2015 as a result of a decline in oil and natural gas prices at the measurement date, March 31, 2015. The first quarter 2015 impairment was calculated based on the 12-month average price of $3.91 per MMBtu for natural gas and $82.62 per barrel of crude oil.

Selling, general and administrative expenses include the costs of our employees, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses decreased $0.1 million to $5.1 million for the three months ended March 31, 2015 as compared to the same period in 2014, primarily resulting from a change in the accrual of executive and employee bonuses for the 2015 performance year discussed below of about $1.4 million, offset by an increase of about $1.3 million resulting from the hiring of additional employees and payments for transition fees related to our acquisitions. Non-cash compensation expense for the three months ended March 31, 2015 increased $1.1 million to $4.0 million as compared to the same period in 2014, primarily related to the accrual of executive and employee bonuses that will be paid in Company common units rather than in cash.

Other Income and Expense

Interest expense increased to $20.2 million for the three months ended March 31, 2015 from $16.3 million for the three months ended March 31, 2014 primarily due to a higher average outstanding debt under our Reserve-Based Credit Facility during the three months ended March 31, 2015 compared to the same period in 2014.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the acquisitions completed during 2014 compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $32.1 million for the three months ended March 31, 2014. The net gain resulted from the increase in oil and natural gas prices used to value the reserves between the commitment and close dates and have been recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of March 31, 2015, our critical accounting policies were consistent with those discussed in our 2014 Annual Report.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, natural gas and NGLs reserves and related cash flow estimates used in recording the acquisition of oil and natural gas properties and in impairment tests of oil and natural gas properties and goodwill, the fair value of derivative contracts and asset retirement obligations, accrued oil, natural gas and NGLs revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

Liquidity and Capital Resources

Overview

Historically, we have obtained financing through proceeds from bank borrowings, cash flow from operations and from the public equity and debt markets to provide us with the capital resources and liquidity necessary to operate our business. To date, the primary use of capital has been for the acquisition and development of oil and natural gas properties; however, we expect to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we will continually monitor the capital resources available to us to meet future financial obligations, planned capital expenditures, acquisition capital and distributions to our unitholders. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us and our success in drilling for and acquiring additional reserves. We expect to fund our drilling capital expenditures and distributions to unitholders with cash flow from operations, while funding any acquisition capital expenditures that we might incur with borrowings under our Reserve-Based Credit Facility and publicly offered equity and debt, depending on market conditions. As of April 30, 2015, we had $665.5 million available to be borrowed under our Reserve-Based Credit Facility and our current borrowing base is $2.0 billion.

The borrowing base under our Reserve-Based Credit Facility is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the lenders' petroleum engineers utilizing the lenders' internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. We are currently in the process of our semi-annual borrowing base redetermination and anticipate its completion in May 2015.

Based on projected market conditions and lower commodity prices, it is likely that banks will lower their internal projections of oil, natural gas and NGLs prices, and we expect that we will be subject to a decrease in our borrowing base availability in the future. We also currently expect that we will not be in compliance with our debt to adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our debt to adjusted EBITDA covenant during the May 2015 semi-annual borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted adjusted EBITDA due to lower commodity prices. Absent the success of amending our leverage ratio, a resultant breach of the covenants under our Reserve-Based Credit Facility would cause a default under the reserve-based credit agreement and the lenders would be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. This, in turn, would cause a default under the senior notes due in 2020 and permit the holders of those notes to accelerate their maturity.

As a result, absent accretive acquisitions, to the extent available after unitholder distributions, debt service and capital expenditures, it is our current intention to utilize our excess cash flow during 2015 to reduce our borrowings under our Reserve-Based Credit Facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient for the conduct of our business and operations for the foreseeable future.

Cash Flow from Operations

Net cash provided by operating activities was $113.7 million during the three months ended March 31, 2015, compared to $79.7 million during the three months ended March 31, 2014. Changes in working capital increased total cash flows by $48.1 million and $6.6 million for the three months ended March 31, 2015 and 2014, respectively. Contributing to the increase in working capital during 2015 was a $56.4 million decrease in accounts receivable related to the timing of receipts from production. The increase in working capital was offset by a $9.4 million decrease in accounts payable, oil and natural gas revenue payable and accrued expenses and other current liabilities that resulted primarily from the timing effects of payments. The change in the fair value of our derivative contracts are non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the three months ended March 31, 2015 or 2014.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, natural gas and NGLs prices. Oil, natural gas and NGLs prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather, and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, respectively, as well as the prices received for production. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we use a combination of fixed-price swaps, basis swaps, call options sold, put options sold, call spreads, call options, put options, three-way collars and range bonus accumulators to reduce our exposure to the volatility in oil and natural gas prices. However, unlike natural gas, we are unable to hedge certain oil price differentials which could significantly impact our cash flow from operations. See Note 4. Price and Interest Rate Risk Management Activities in the Notes to Consolidated Financial Statements and Part I—Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk, for details about derivative contracts in place through 2017.

Cash Flow from Investing Activities

Net cash used in investing activities was approximately $25.9 million for the three months ended March 31, 2015, compared to $525.2 million during the same period in 2014. Cash used in investing activities during the first three months of 2015 primarily included $25.1 million for the drilling and development of oil and natural gas properties. Net cash used in investing activities during the first three months of 2014 was primarily attributable to $496.7 million for the acquisition of oil and natural gas properties, $28.0 million for the drilling and development of oil and natural gas properties, $0.2 million for additions to property and equipment and $0.3 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties.

Cash Flow from Financing Activities

Net cash used in financing activities was approximately $73.3 million for the three months ended March 31, 2015, compared to net cash provided by financing activities of $454.6 million during the same period in 2014. Cash used in financing activities during the three months ended March 31, 2015 included $31.1 million in net repayments of our long-term debt and $52.0 million cash paid to preferred, common and Class B unitholders in the form of distributions. Additionally, cash provided by financing activities during the three months ended March 31, 2015 included net proceeds from our public common unit offerings of $12.2 million. Net cash provided by financing activities during the three months ended March 31, 2014 included net proceeds from our public common unit and preferred unit offerings of $204.6 million and net proceeds from borrowings under our long-term debt of $301.0 million, offset by $51.0 million cash used in distributions to preferred, common and Class B unitholders.

Debt and Credit Facilities

Reserve-Based Credit Facility

The Company's Third Amended and Restated Credit Agreement (the "Credit Agreement") provides a maximum credit facility of $3.5 billion and a borrowing base of $2.0 billion (the "Reserve-Based Credit Facility"). As of March 31, 2015, there were approximately $1.33 billion of outstanding borrowings and $665.5 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $4.5 million reduction in availability for letters of credit (discussed below).

The applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

| Borrowing Base Utilization Percentage | <25% | | >25% <50% | | >50% <75% | | >75% <90% | | >90% | |
|---|---|---|---|---|---|---|---|---|---|---|
| Eurodollar Loans Margin | 1.50 | % | 1.75 | % | 2.00 | % | 2.25 | % | 2.50 | % |
| ABR Loans Margin | 0.50 | % | 0.75 | % | 1.00 | % | 1.25 | % | 1.50 | % |
| Commitment Fee Rate | 0.50 | % | 0.50 | % | 0.375 | % | 0.375 | % | 0.375 | % |
| Letter of Credit Fee | 0.50 | % | 0.75 | % | 1.00 | % | 1.25 | % | 1.50 | % |

The borrowing base is subject to adjustment from time to time (but not less than on a semi-annual basis) based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future oil, natural gas and NGLs prices) from our proved oil, natural gas and NGLs reserves. We are currently in the process of our semi-annual borrowing base redetermination and anticipate its completion in May 2015. Based on projected market conditions and lower commodity prices, it is likely that banks will lower their internal projections of oil, natural gas and NGLs prices, and we expect that we will be subject to a decrease in our borrowing base availability in the future. We also currently expect that we will not be in compliance with our debt to adjusted EBITDA covenant in certain future periods. We have been in discussions with certain banks in our Reserve-Based Credit Facility regarding amending our debt to adjusted EBITDA covenant during this borrowing base redetermination. Based on those discussions, it is our expectation that the covenant will be changed to provide for more flexibility given lower forecasted adjusted EBITDA due to the lower commodity price environment.

As of April 30, 2015, we have $665.5 million available to be borrowed under our Reserve-Based Credit Facility, after reflecting a $4.5 million reduction in availability for letters of credit (as discussed below).

Borrowings under the Reserve-Based Credit Facility are available for development and acquisition of oil and natural gas properties, working capital and general limited liability company purposes. Our obligations under the Reserve-Based Credit Facility are secured by substantially all of our assets.

At our election, interest is determined by reference to:

- the London interbank offered rate, or LIBOR, plus an applicable margin between 1.50% and 2.50% per annum; or
- a domestic bank rate plus an applicable margin between 0.50% and 1.50% per annum.

As of March 31, 2015, we had elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

The Reserve-Based Credit Facility contains various covenants that limit our ability to:

- incur indebtedness;
- grant certain liens;
- make certain loans, acquisitions, capital expenditures and investments;
- merge or consolidate; or
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

The Reserve-Based Credit Facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC Topic 815, “Derivatives and Hedging,” which includes the current portion of derivative contracts; and
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 4.0 to 1.0.

We have the ability to borrow under the Reserve-Based Credit Facility to pay distributions to unitholders as long as there has not been a default or an event of default.

We believe that we were in compliance with the terms of our Reserve-Based Credit Facility at March 31, 2015. If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the Reserve-Based Credit Facility and exercise other rights and remedies. Each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $5.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of 2% of the existing borrowing base (to the extent not covered by independent third party insurance provided by insurers of the highest claims paying rating or financial strength as to which the insurer does not dispute coverage and is not subject to insolvency proceeding) or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.0 million in any year; and
- a change of control, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Securities Exchange Act of 1934 (the “Exchange Act”) and the rules and regulations of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Letters of Credit

At March 31, 2015, we have unused irrevocable standby letters of credit of approximately $4.5 million. The letters are being maintained as security for performance on long-term transportation contracts. Borrowing availability for the letters of credit is provided under our Reserve-Based Credit Facility. The fair value of these letters of credit approximates contract values based on the nature of the fee arrangements with the issuing banks.

Senior Notes

We have $550.0 million outstanding in aggregate principal amount of 7.875% senior notes due 2020 (the “Senior Notes”). The issuers of the Senior Notes are VNR and our 100% owned finance subsidiary, VNRF. VNR has no independent assets or operations. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF), all of which are 100% owned, and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to certain customary release provisions, including: (i) upon the sale or other disposition of all or substantially all of the subsidiary’s properties or assets; (ii) upon the sale or other disposition of our equity interests in the subsidiary; (iii) upon designation of the subsidiary as an unrestricted subsidiary in accordance with the terms of the Indenture; (iv) upon legal defeasance or covenant defeasance or the discharge of the Indenture; (v) upon the liquidation or dissolution of the subsidiary; (vi) upon the subsidiary ceasing to guarantee any other of our indebtedness and to be an obligor under any of our credit facilities; or (vii) upon such subsidiary dissolving or ceasing to exist after consolidating with, merging into or transferring all of its properties or assets to us.

The Indenture also contains covenants that will limit our ability to (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) make distributions on, purchase or redeem our common units or purchase or redeem subordinated indebtedness; (iv) make investments; (v) restrict dividends, loans or other asset transfers from our restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of our properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; (viii) enter into transactions with affiliates; or (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. If the Senior Notes achieve an investment grade rating from each of Standard & Poor's Rating Services and Moody's Investors Services, Inc. and no default under the Indenture exists, many of the foregoing covenants will terminate. At March 31, 2015, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, approximately $74.5 million of members' equity is available for distributions to unitholders, while the remainder is restricted.

Interest on the Senior Notes is payable on April 1 and October 1 of each year, beginning on October 1, 2012. We may redeem some or all of the Senior Notes at any time on or after April 1, 2016 at redemption prices of 103.9375% of the aggregate principal amount of the Senior Notes as of April 1, 2016, declining to 100% on April 1, 2018 and thereafter.  We may also redeem some or all of the Senior Notes at any time prior to April 1, 2016 at a redemption price equal to 100% of the aggregate principal amount of the Senior Notes thereof, plus a "make-whole" premium. In addition, before April 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price equal to 107.875% of the aggregate principal amount of the Senior Notes thereof, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of the Senior Notes remain outstanding immediately after any such redemption and the redemption occurs within 180 days of such equity offering. If we sell certain of our assets or experience certain changes of control, we may be required to repurchase all or a portion of the Senior Notes at a price equal to 100% and 101% of the aggregate principal amount of the Senior Notes, respectively.

Lease Financing Obligations

On October 24, 2014, as part of our Piceance Acquisition, we entered into an assignment and assumption agreement with Bank of America Leasing & Capital, LLC as the lead bank, whereby we acquired compressors and related facilities, and assumed the related financing obligations (the "Lease Financing Obligations"). Certain rights, title, interest and obligations under the Lease Financing Obligations have been assigned to several lenders and are covered by separate assignment agreements, which expire on August 10, 2020 and July 10, 2021. We have the option to purchase the equipment at the end of the lease term for the then current fair market value. The Lease Financing Obligations also contain an early buyout option whereby the Company may purchase the equipment for $16.0 million on February 10, 2019. The lease payments related to the equipment are recognized as principal and interest expense based on a weighted average implicit interest rate of 4.16%.

Off-Balance Sheet Arrangements

At March 31, 2015, we did not have any off-balance sheet arrangements that have, or are reasonably likely to have, an effect on our financial position or results of operations.

Contingencies

We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Commitments and Contractual Obligations

A summary of our contractual obligations as of March 31, 2015 is provided in the following table (in thousands):

| | Payments Due by Year | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | After 2019 | Total |
| Management base salaries (1) | $1,053 | $— | $— | $— | $— | $— | $1,053 |
| Asset retirement obligations (2) | 14,370 | 12,466 | 4,550 | 5,826 | 3,001 | 110,764 | 150,977 |
| Derivative liabilities (3) | 31,928 | 24,986 | 7,655 | — | — | — | 64,569 |
| Reserve-Based Credit Facility (4) | — | — | — | 1,330,000 | — | — | 1,330,000 |
| Senior Notes and related interest | 43,791 | 43,313 | 43,313 | 43,313 | 43,312 | 564,438 | 781,480 |
| Operating leases | 902 | 1,071 | 1,089 | 1,337 | 1,342 | 216 | 5,957 |
| Development commitments (5) | 45,205 | — | — | — | — | — | 45,205 |
| Firm transportation agreements (6) | 13,046 | 14,508 | 12,362 | 11,696 | 9,661 | 410 | 61,683 |
| Lease Financing Obligations (7) | $3,255 | $4,501 | $4,692 | $4,891 | $5,098 | $5,486 | $27,923 |
| Total | $153,550 | $100,845 | $73,661 | $1,397,063 | $62,414 | $681,314 | $2,468,847 |

(1) Our Board of Directors approved the option for the VNR management team to receive VNR common units in lieu of 2015 cash compensation. Messrs. Smith and Robert elected this option and under the plan will receive quarterly grants of VNR common units instead of their remaining 2015 full cash compensation totaling $750,000.

(2) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and the decommissioning of the Elk Basin and Fairway gas plants. Please read Note 6. Asset Retirement Obligations of the Notes to the Consolidated Financial Statements for additional information regarding our asset retirement obligations.

(3) Represents liabilities for commodity and interest rate derivative contracts, the ultimate settlement of which are unknown because they are subject to continuing market risk. Please read Part I—Item 3—Quantitative and Qualitative Disclosures About Market Risk and Note 4. Price and Interest Rate Risk Management Activities of the Notes to the Consolidated Financial Statements for additional information regarding our commodity and interest rate derivative contracts.

(4) This table does not include interest to be paid on the Reserve-Based Credit Facility principal balances shown as the interest rates are variable. Please read Note 3. Long-Term Debt of the Notes to the Consolidated Financial Statements for additional information regarding our Reserve-Based Credit Facility.

(5) Represents authorized purchases for work in process.

(6) Represents gross transportation demand charges. Please read Note 7. Commitments and Contingencies of the Notes to the Consolidated Financial Statements for additional information regarding our firm transportation agreements.

(7) The Lease Financing Obligations are calculated based on the aggregate present value of minimum future lease payments.

## Non-GAAP Financial Measure

### Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income (loss) in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) plus the following adjustments:

- Net interest expense;
- Depreciation, depletion, amortization and accretion;
- Impairment of oil and natural gas properties;
- Net gains or losses on commodity derivative contracts;
- Cash settlements on matured commodity derivative contracts;
- Net gains or losses on interest rate derivative contracts;
- Net gain on acquisition of oil and natural gas properties;
- Texas margin taxes; and
- Compensation related items, which include unit-based compensation expense, unrealized fair value of phantom units granted to officers and cash settlement of phantom units granted to officers.

Adjusted EBITDA is a significant performance metric used by management as a tool to measure (prior to the establishment of any cash reserves by our board of directors, debt service and capital expenditures) the cash distributions we could pay our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our monthly distribution rates. Adjusted EBITDA is also used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and our operating performance and return on capital as compared to those of other companies in our industry.

Our Adjusted EBITDA should not be considered as an alternative to net income (loss), operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies. For example, we fund premiums paid for derivative contracts, acquisitions of oil and natural gas properties, including the assumption of derivative contracts related to these acquisitions, and other capital expenditures primarily with proceeds from debt or equity offerings or with borrowings under our Reserve-Based Credit Facility. For the purposes of calculating Adjusted EBITDA, we consider the cost of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investments related to our underlying oil and natural gas properties; therefore, they are not deducted in arriving at our Adjusted EBITDA. Our Consolidated Statements of Cash Flows, prepared in accordance with GAAP, present cash settlements on matured derivatives and the initial cash outflows of premiums paid to enter into derivative contracts as operating activities. When we assume derivative contracts as part of a business combination, we allocate a part of the purchase price and assign them a fair value at the closing date of the acquisition. The fair value of the derivative contracts acquired is recorded as a derivative asset or liability and presented as cash used in investing activities in our Consolidated Statements of Cash Flows. As the volumes associated with these derivative contracts, whether we entered into them or we assumed them, are settled, the fair value is recognized in operating cash flows. Whether these cash settlements on derivatives are received or paid, they are reported as operating cash flows which may increase or decrease the amount we have available to fund distributions.

As noted above, for purposes of calculating Adjusted EBITDA, we consider both premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities. This is similar to the way the initial acquisition or development costs of our oil and natural gas properties are presented in our Consolidated Statements of Cash Flows; the initial cash outflows are presented as cash used in investing activities, while the cash flows generated from these assets are included in operating cash flows. The consideration of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities for purposes of determining our Adjusted EBITDA differs from the presentation in our consolidated financial statements prepared in accordance with GAAP which (i) presents premiums paid for derivatives entered into as operating activities and (ii) the fair value of derivative contracts acquired as part of a business combination as investing activities.

For the three months ended March 31, 2015, as compared to the three months ended March 31, 2014, Adjusted EBITDA decreased 5%, from $89.9 million to $85.3 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2015 | 2014 |
| Net income (loss) | $(118,830) | $15,121 |
| Plus: | | |
| Interest expense | 20,189 | 16,259 |
| Depreciation, depletion, amortization, and accretion | 66,840 | 43,610 |
| Impairment of oil and natural gas properties | 132,610 | — |
| Net (gains) losses on commodity derivative contracts | (59,033) | 56,037 |
| Cash settlements on matured commodity derivative contracts [(a)(b)(c)] | 38,291 | (11,969) |
| Net losses on interest rate derivative contracts [(d)] | 1,203 | 458 |
| Gain on acquisition of oil and natural gas properties | — | (32,114) |
| Texas margin taxes | 108 | (411) |
| Compensation related items | 3,961 | 2,872 |
| Adjusted EBITDA | $85,339 | $89,863 |

| | | |
|---|---|---|
| (a) Excludes premiums paid, whether at inception or deferred, for derivative contracts that settled during the period. We consider the cost of premiums paid for derivatives as an investment related to our underlying oil and natural gas properties. | $520 | $— |
| (b) Excludes the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. We consider the amounts paid to sellers for derivative contracts assumed with business combinations a part of the purchase price of the underlying oil and natural gas properties. Also excludes the fair value of derivative contracts acquired and settled during the period. | $8,549 | $4,882 |
| (c) Excludes fair value of restructured derivative contracts. | $(31,945) | $— |
| (d) Includes settlements paid on interest rate derivatives | $990 | $990 |

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas and NGLs prices and interest rates. The disclosures are not meant to be precise indicators of exposure, but rather indicators of potential exposure. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Conditions sometimes arise where actual production is less than estimated, which has, and could result in over-hedged volumes.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil, natural gas and NGLs production. Realized pricing is primarily driven by prevailing spot regional market prices at our primary sales points and the applicable index prices. Pricing for oil, natural gas and NGLs production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level, the borrowing base for our Reserve-Based Credit Facility can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes. Furthermore, the risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase.

We routinely enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that mitigate the volatility of future prices received as follows:

- Fixed-price swaps - where we will receive a fixed-price for our production and pay a variable market price to the contract counterparty.
- Basis swap contracts - which guarantee a price differential between the NYMEX prices and our physical pricing points. We receive a payment from the counterparty or make a payment to the counterparty for the difference between the settled price differential and amounts stated under the terms of the contract.
- Collars - where we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor (long put) on a notional quantity.
- Put options - gives the owner the right, but not the obligation, to sell a specified amount of an underlying security at a specified price.
- Three-way collar contracts - which combine a long put, a short put and a short call. The use of the long put combined with the short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limiting our exposure to future settlement payments while also restricting our downside risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle for market plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.
- Swaption agreements - where we provide options to counterparties to extend swap contracts into subsequent years.
- Call options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a call option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put options sold - a structure that may be combined with an existing swap to raise the strike price, putting us in either a higher asset position, or a lower liability position. In general, selling a put option is used to enhance an existing position or a position that we intend to enter into simultaneously.
- Put or Call spread options - created when we purchase a put/call and sell a put/call simultaneously.

- Range bonus accumulators - a structure that allows us to receive a cash payment when the daily average settlement price remains within a predefined range on each expiry date. Depending on the terms of the contract, if the settlement price is below the floor or above the ceiling on any expiry date, we may have to sell at that level.

In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management's view on future commodity pricing. The amount of oil and natural gas production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Substantially all of our natural gas hedges are at regional sales points in our operating regions, which mitigate the risk of basis differential to the Henry Hub index. Typically, management intends to hedge 75% to 85% of projected oil and natural gas production up to a four year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We have also entered into fixed-price swaps derivative contracts to cover a portion of our NGLs production to reduce exposure to fluctuations in NGLs prices. However, a liquid, readily available and commercially viable market for hedging NGLs has not developed in the same way that exists for crude oil and natural gas. The current direct NGL hedging market is constrained in terms of price, volume, duration and number of counterparties, which limits our ability to hedge our NGL production effectively or at all. It is never management's intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract, if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At March 31, 2015, the fair value of commodity derivative contracts was an asset of approximately $249.8 million, of which $148.9 million settles during the next twelve months.

The following table summarizes natural gas commodity derivative contracts in place at March 31, 2015:

| | April 1 - December 31, 2015 | Year 2016 | Year 2017 |
|---|---|---|---|
| Gas Positions: | | | |
| Fixed-Price Swaps: | | | |
| Notional Volume (MMBtu) | 66,137,500 | 55,083,000 | 24,027,000 |
| Fixed Price ($/MMBtu) | $4.26 | $4.47 | $4.35 |
| Three-Way Collars: | | | |
| Notional Volume (MMBtu) | — | 12,810,000 | 16,425,000 |
| Floor Price ($/MMBtu) | $— | $3.95 | $3.92 |
| Ceiling Price ($/MMBtu) | $— | $4.25 | $4.23 |
| Put Sold ($/MMBtu) | $— | $3.00 | $3.37 |
| Total Gas Positions: | | | |
| Notional Volume (MMBtu) | 66,137,500 | 67,893,000 | 40,452,000 |
| Floor Price ($/MMBtu) | $4.26 | $4.37 | $4.18 |

| | April 1 - December 31, 2015 | Year 2016 | Year 2017 |
|---|---|---|---|
| Oil Positions: | | | |
| Fixed-Price Swaps: | | | |
| Notional Volume (Bbls) | 1,846,750 | 146,400 | — |
| Fixed Price ($/Bbl) | $73.07 | $89.98 | $— |
| Collars: | | | |
| Notional Volume (Bbls) | 274,500 | — | — |
| Floor Price ($/Bbl) | $50.00 | $— | $— |
| Ceiling Price ($/Bbl) | $56.85 | $— | $— |
| Puts: | | | |
| Notional Volume (Bbls) | — | 366,000 | — |
| Put Price ($/Bbl) | $— | $60.00 | $— |
| Three-Way Collars: | | | |
| Notional Volume (Bbls) | 160,750 | 1,061,400 | — |
| Floor Price ($/Bbl) | $90.00 | $90.00 | $— |
| Ceiling Price ($/Bbl) | $97.26 | $96.18 | $— |
| Put Sold ($/Bbl) | $76.43 | $73.62 | $— |
| Total Oil Positions: | | | |
| Notional Volume (Bbls) | 2,282,000 | 1,573,800 | — |
| Floor Price ($/Bbl) | $71.49 | $83.02 | $— |

| | April 1 - December 31, 2015 |
|---|---|
| NGLs Positions: | |
| Fixed-Price Swaps: | |
| Mont Belvieu Propane | |
| Notional Volume (Bbls) | 123,750 |
| Fixed Price ($/Bbl) | $43.21 |
| Mont Belvieu N. Butane | |
| Notional Volume (Bbls) | 27,500 |
| Fixed Price ($/Bbl) | $52.08 |
| Mont Belvieu Isobutane | |
| Notional Volume (Bbls) | 34,375 |
| Fixed Price ($/Bbl) | $53.00 |
| Total NGLs Positions: | |
| Notional Volume (Bbls) | 185,625 |
| Fixed Price ($/Bbl) | $46.34 |

As of March 31, 2015, the Company sold the following put option contracts:

| | April 1 - December 31, 2015 | Year 2016 | Year 2017 |
|---|---|---|---|
| Gas Positions: | | | |
| Notional Volume (MMBtu) | 19,937,500 | 1,830,000 | 1,825,000 |
| Put Sold ($/MMBtu) | $2.99 | $3.00 | $3.50 |
| Oil Positions: | | | |
| Notional Volume (Bbls) | 476,000 | 146,400 | 73,000 |
| Put Sold ($/Bbl) | $72.11 | $75.00 | $75.00 |

As of March 31, 2015, the Company had the following open range bonus accumulators contracts:

| | April 1 - December 31, 2015 | Year 2016 |
|---|---|---|
| Gas Positions: | | |
| Notional Volume (MMBtu) | 1,100,000 | — |
| Bonus ($/MMBtu) | $0.16 | $— |
| Range Ceiling ($/MMBtu) | $4.00 | $— |
| Range Floor ($/MMBtu) | $2.50 | $— |
| Oil Positions: | | |
| Notional Volume (Bbls) | 137,500 | 183,000 |
| Bonus ($/Bbl) | $4.00 | $4.00 |
| Range Ceiling ($/Bbl) | $100.00 | $100.00 |
| Range Floor ($/Bbl) | $75.00 | $75.00 |

As of March 31, 2015, the Company had the following open basis swap contracts:

| | April 1 - December 31, 2015 | Year 2016 | Year 2017 |
|---|---|---|---|
| Gas Positions: | | | |
| Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential | | | |
| Notional Volume (MMBtu) | 22,000,000 | 18,300,000 | 10,950,000 |
| Weighted-basis differential ($/MMBtu) | $(0.28) | $(0.24) | $(0.22) |

| | April 1 - December 31, 2015 |
|---|---|
| Oil Positions: | |
| WTI Midland and WTI Cushing Basis Differential | |
| Notional Volume (Bbls) | 385,000 |
| Weighted-basis differential ($/Bbl) | $(1.68) |
| West Texas Sour and WTI Cushing Basis Differential | |
| Notional Volume (Bbls) | 110,000 |
| Weighted-basis differential ($/Bbl) | $(2.33) |
| WTI and West Canadian Select Basis Differential | |
| Notional Volume (Bbls) | 550,000 |
| Weighted-basis differential ($/Bbl) | $(14.50) |

43

As of March 31, 2015, the Company sold calls as follows:

| | April 1 - December 31, 2015 | Year 2016 | Year 2017 |
|---|---|---|---|
| Gas Positions: | | | |
| Notional Volume (MMBtu) | — | 9,150,000 | 9,125,000 |
| Weighted Average Fixed Price ($/MMBtu) | $— | $4.25 | $4.50 |
| Oil Positions: | | | |
| Notional Volume (Bbls) | 55,000 | 622,200 | 365,000 |
| Weighted Average Fixed Price ($/Bbl) | $105.00 | $125.00 | $95.00 |

As of March 31, 2015, the Company had the following open call spread contracts:

| | April 1 - December 31, 2015 |
|---|---|
| Oil Positions: | |
| Notional Volume (Bbls) | 947,600 |
| Call Price ($/Bbl) | $70.00 |
| Short Call Price ($/Bbl) | $85.00 |

Interest Rate Risks

At March 31, 2015, we had debt outstanding of $1.9 billion. The amount outstanding under our Reserve-Based Credit Facility at March 31, 2015 was approximately $1.33 billion and is subject to interest at floating rates based on LIBOR. If the debt remains the same, a 10% increase in LIBOR would result in an estimated $0.2 million increase in annual interest expense after consideration of the interest rate swaps discussed below.

We enter into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. The Company records changes in the fair value of its interest rate derivatives in current earnings under net gains or losses on interest rate derivative contracts.

The following summarizes information concerning our positions in open interest rate derivative contracts at March 31, 2015 (in thousands):

| | Year 2015(1)(2) | Year 2016 |
|---|---|---|
| Weighted Average Notional Amount | $256,192 | $169,399 |
| Weighted Average Fixed LIBOR Rate | 1.26 % | 1.49 % |

(1) On August 5, 2015, the counterparty has the option to extend the termination date of a contract for a notional amount of $30.0 million at 2.25% to August 5, 2018.
(2) The counterparty has the option to require Vanguard to pay a fixed rate of 0.91% for a notional amount of $50.0 million from December 10, 2015 to December 10, 2017.

Counterparty Risk

At March 31, 2015, based upon all of our open derivative contracts shown above and their respective mark to market values, we had the following current and long-term derivative assets and liabilities shown by counterparty with their current Standard & Poor’s financial strength rating in parentheses (in thousands):

44

| | Current Assets | Long-Term Assets | Current Liabilities | Long-Term Liabilities | Total Amount Due From/(Owed To) Counterparty at March 31, 2015 |
|---|---|---|---|---|---|
| ABN AMRO (A) | $ 1,137 | $2,132 | $— | $— | $3,269 |
| Bank of America (A) | 11,184 | 9,571 | (767) | (87) | 19,901 |
| Barclays (A) | 8,976 | 4,957 | — | — | 13,933 |
| BMO (A+) | 5,907 | 4,725 | — | — | 10,632 |
| CIBC (A+) | 2,071 | 1,684 | — | — | 3,755 |
| Citibank (A) | 9,972 | 1,626 | — | — | 11,598 |
| Comerica (A) | 1,784 | 763 | — | — | 2,547 |
| Commonwealth Bank of Australia (AA-) | 1,018 | 851 | — | — | 1,869 |
| Credit Agricole (A) | — | — | (460) | (179) | (639) |
| Fifth Third Bank (A-) | 4,856 | 741 | — | — | 5,597 |
| ING Financial Markets (A) | 2,294 | 1,179 | — | — | 3,473 |
| JP Morgan (A) | 37,158 | 34,299 | — | — | 71,457 |
| Morgan Stanley (A-) | 8,543 | 6,056 | — | — | 14,599 |
| Natixis (A) | 11,657 | 3,207 | — | — | 14,864 |
| PNC (A-) | 216 | — | — | — | 216 |
| RBC (AA-) | 7,764 | 7,838 | (114) | — | 15,488 |
| Shell (AA-) | — | — | (12) | — | (12) |
| Scotia Capital (A+) | 20,401 | 13,516 | (846) | (481) | 32,590 |
| SunTrust (A-) | 1,326 | 1,088 | — | — | 2,414 |
| Wells Fargo (AA-) | 12,634 | 6,724 | (1,669) | (278) | 17,411 |
| Total | $ 148,898 | $100,957 | $(3,868) | $(1,025) | $244,962 |

In order to mitigate the credit risk of financial instruments, we enter into master netting agreements with our counterparties. The master netting agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each financial transaction between the counterparty and us separately, the master netting agreement enables the counterparty and us to aggregate all financial trades and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (1) default by a counterparty under one financial trade can trigger rights to terminate all financial trades with such counterparty; and (2) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out. Under the master netting agreement, the maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the net fair value of financial instruments, was approximately $245.6 million at March 31, 2015.

## Item 4. Controls and Procedures

### Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of March 31, 2015 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the first quarter of 2015 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 defendants in legal proceedings arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of these actions will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

### Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed in this Quarterly Report or our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our securities, please refer to Part I-Item 1A-Risk Factors in our 2014 Annual Report. There have been no material changes to the risk factors set forth in our 2014 Annual Report.

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

During the three months ended March 31, 2015, one of our wholly-owned subsidiaries purchased 157,156 of our common units on the open market at the then prevailing market price. The average price paid per common unit was $15.27. The repurchased units were subsequently granted to two of our executive officers, Messrs. Smith and Robert and our three independent directors, Loren Singletary, Richard W. Anderson and Bruce W. McCullough, who elected to receive quarterly unit grants in lieu of their 2015 cash compensation.

### Item 3. Defaults Upon Senior Securities

None.

### Item 4. Mine Safety Disclosures

Not applicable.

### Item 5. Other Information

None.

### Item 6. Exhibits

EXHIBIT INDEX

Each exhibit identified below is filed as a part of this Report.

| Exhibit No. | Exhibit Title | Incorporated by Reference to the Following |
|---|---|---|
| 3.1 | Fifth Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC. | Form 8-K, filed September 15, 2014 (File No. 001-33756) |
| 4.1 | Specimen Unit Certificate for the Series A Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit B to Exhibit 3.1). | Form 8-K, filed September 15, 2014 (File No. 001-33756) |
| 4.2 | Specimen Unit Certificate for the Series B Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit C to Exhibit 3.1). | Form 8-K, filed September 15, 2014 (File No. 001-33756) |
| 4.3 | Specimen Unit Certificate for the Series C Cumulative Redeemable Perpetual Preferred Units (incorporated herein by reference to Exhibit D to Exhibit 3.1). | Form 8-K, filed September 15, 2014 (File No. 001-33756) |
| 10.1 | Seventh Amendment, dated October 30, 2014, to Third Amended and Restated Credit Agreement, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party thereto | Filed herewith |
| 31.1 | Certification of Chief Executive Officer Pursuant to Rule 13a -14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | Filed herewith |
| 31.2 | Certification of Chief Financial Officer Pursuant to Rule 13a -14(a) and Rule 15d-14(a) of the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | Filed herewith |
| 32.1 | Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | Furnished herewith |
| 32.2 | Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | Furnished herewith |
| 101.INS | XBRL Instance Document | Filed herewith |
| 101.SCH | XBRL Schema Document | Filed herewith |
| 101.CAL | XBRL Calculation Linkbase Document | Filed herewith |
| 101.DEF | XBRL Definition Linkbase Document | Filed herewith |
| 101.LAB | XBRL Label Linkbase Document | Filed herewith |
| 101.PRE | XBRL Presentation Linkbase Document | Filed herewith |

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.

VANGUARD NATURAL RESOURCES, LLC
(Registrant)

Date: May 4, 2015

/s/ Richard A. Robert

Richard A. Robert
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal
Accounting Officer)