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

FORM 10-Q

(Mark One)

☒	**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2014

OR

☐	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission File Number: 001-33756

Vanguard Natural Resources, LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1521161**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
5847 San Felipe, Suite 3000 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. ☒ Yes ☐ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

☒ Large accelerated filer	☐ Accelerated filer
☐ Non-accelerated filer (Do not check if a smaller reporting company)	☐ Smaller reporting company

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

Common units outstanding on July 31, 2014: 83,055,732.

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
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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, 2013 (the "2013 Annual Report"), our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$ 73,963	$ 69,701	$ 142,163	$ 128,217
Natural gas sales	69,806	36,010	133,348	63,534
NGLs sales	17,750	11,026	38,748	21,668
Net gains (losses) on commodity derivative contracts	(38,398)	58,595	(94,436)	29,320
Total revenues	123,121	175,332	219,823	242,739
Costs and expenses:				
Production:				
Lease operating expenses	34,293	26,509	64,715	50,682
Production and other taxes	16,529	9,964	31,563	19,307
Depreciation, depletion, amortization, and accretion	51,508	42,911	95,118	81,604
Selling, general and administrative expenses	7,864	6,900	15,902	13,449
Total costs and expenses	110,194	86,284	207,298	165,042
Income from operations	12,927	89,048	12,525	77,697
Other income (expense):				
Interest expense	(16,549)	(15,963)	(32,808)	(31,401)
Net gains (losses) on interest rate derivative contracts	(1,121)	2,412	(1,579)	2,127
Gains on acquisitions of oil and natural gas properties	—	5,827	32,114	5,827
Other	6	(23)	131	28
Total other income (expense)	(17,664)	(7,747)	(2,142)	(23,419)
Net income (loss)	$ (4,737)	$ 81,301	$ 10,383	$ 54,278
Distributions to Preferred unitholders	(4,596)	(152)	(6,558)	(152)
Net income (loss) attributable to Common and Class B unitholders	$ (9,333)	$ 81,149	$ 3,825	$ 54,126
Net income (loss) per Common and Class B unit – basic and diluted	$ (0.12)	$ 1.14	$ 0.05	$ 0.80
Weighted average Common units outstanding				
Common units – basic & diluted	80,536	70,798	79,865	67,601
Class B units – basic & diluted	420	420	420	420

See accompanying notes to consolidated financial statements

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

	June 30, 2014	December 31, 2013
	(Unaudited)	
Assets		
Current assets		
Cash and cash equivalents	$ 22,113	$ 11,818
Trade accounts receivable, net	91,337	70,109
Derivative assets	9,432	21,314
Other current assets	3,597	2,916
Total current assets	126,479	106,157
Oil and natural gas properties, at cost	3,213,473	2,523,671
Accumulated depletion, amortization and impairment	(804,814)	(713,154)
Oil and natural gas properties evaluated, net – full cost method	2,408,659	1,810,517
Other assets		
Goodwill	420,955	420,955
Derivative assets	25,030	60,474
Other assets	29,196	91,538
Total assets	$ 3,010,319	$ 2,489,641
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 18,051	$ 9,824
Affiliates	401	249
Accrued liabilities:		
Lease operating	14,905	12,882
Development capital	19,894	10,543
Interest	11,646	11,989
Production and other taxes	23,371	16,251
Derivative liabilities	35,794	10,992
Oil and natural gas revenue payable	21,627	23,245
Distribution payable	17,996	16,499
Other	13,882	12,929
Total current liabilities	177,567	125,403
Long-term debt	1,273,011	1,007,879
Derivative liabilities	7,931	4,085
Asset retirement obligations, net of current portion	106,775	82,208
Other long-term liabilities	—	1,731
Total liabilities	1,565,284	1,221,306
Commitments and contingencies (Note 7)		
Members' equity		
Series A Preferred units, 2,561,661 units issued and outstanding at June 30, 2014 and 2,535,927 at December 31, 2013	61,682	61,021
Series B Preferred units, 7,000,000 units issued and outstanding at June 30, 2014	169,265	—
Common units, 82,017,879 units issued and outstanding at June 30, 2014 and 78,337,259 at December 31, 2013	1,206,473	1,199,699
Class B units, 420,000 issued and outstanding at June 30, 2014 and December 31, 2013	7,615	7,615
Total members' equity	1,445,035	1,268,335
Total liabilities and members' equity	$ 3,010,319	$ 2,489,641

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2014 AND THE YEAR ENDED DECEMBER 31, 2013
(in thousands)
(Unaudited)

	Series A Preferred Units		Series B Preferred Units		Common Units		Class B		Total Members' Equity
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	
Balance at January 1, 2013	—	$ —	—	$ —	58,706	$ 789,849	420	$ 7,615	$ 797,464
Issuance of Common units for the acquisition of oil and natural gas properties	—	—	—	—	1,075	29,992	—	—	29,992
Issuance of Preferred units, net of offering costs of $402	2,536	61,021	—	—	—	—	—	—	61,021
Issuance of Common units, net of offering costs of $415	—	—	—	—	18,377	498,360	—	—	498,360
Distributions to Preferred unitholders (see Note 8)	—	—	—	—	—	(2,634)	—	—	(2,634)
Distributions to Common and Class B unitholders (see Note 8)	—	—	—	—	—	(181,926)	—	—	(181,926)
Unit-based compensation	—	—	—	—	179	6,547	—	—	6,547
Net income	—	—	—	—	—	59,511	—	—	59,511
Balance at December 31, 2013	2,536	$ 61,021	—	$ —	78,337	$1,199,699	420	$ 7,615	$1,268,335
Issuance of Preferred units, net of offering costs of $222	26	661	7,000	169,265	—	—	—	—	169,926
Issuance of Common units, net of offering costs of $38	—	—	—	—	3,324	100,397	—	—	100,397
Distributions to Preferred unitholders (see Note 8)	—	—	—	—	—	(6,558)	—	—	(6,558)
Distributions to Common and Class B unitholders (see Note 8)	—	—	—	—	—	(101,646)	—	—	(101,646)
Unit-based compensation	—	—	—	—	357	4,198	—	—	4,198
Net income	—	—	—	—	—	10,383	—	—	10,383
Balance at June 30, 2014	2,562	$ 61,682	7,000	$169,265	82,018	$1,206,473	420	$ 7,615	$1,445,035

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating activities		
Net income	$ 10,383	$ 54,278
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	95,118	81,604
Amortization of deferred financing costs	1,720	1,909
Amortization of debt discount	132	121
Compensation related items	4,010	3,503
Net (gains) losses on commodity and interest rate derivative contracts	96,015	(31,447)
Cash settlements on matured commodity derivative contracts	(19,380)	18,721
Cash settlements paid on matured interest rate derivative contracts	(2,005)	(1,909)
Gains on acquisitions of oil and natural gas properties	(32,114)	(5,827)
Changes in operating assets and liabilities:		
Trade accounts receivable	(21,228)	(24,177)
Other current assets	3	(783)
Premiums paid on commodity derivative contracts	(983)	(93)
Accounts payable and oil and natural gas revenue payable	6,609	1,070
Payable to affiliates	152	234
Accrued expenses and other current liabilities	16,898	22,117
Other assets	(403)	(366)
Net cash provided by operating activities	154,927	118,955
Investing activities		
Additions to property and equipment	(480)	(1,545)
Additions to oil and natural gas properties	(61,524)	(29,418)
Acquisitions of oil and natural gas properties	(509,416)	(270,535)
Deposits and prepayments of oil and natural gas properties	(3,685)	(1,047)
Proceeds from the sale of leasehold interests	1,950	—
Net cash used in investing activities	(573,155)	(302,545)
Financing activities		
Proceeds from long-term debt	595,000	388,500
Repayment of long-term debt	(330,000)	(638,500)
Proceeds from preferred unit offerings, net	169,926	60,880
Proceeds from Common unit offerings, net	100,397	468,100
Distributions to Preferred unitholders	(5,792)	—
Distributions to Common and Class B unitholders	(100,915)	(80,289)
Financing fees	(93)	(2,053)
Net cash provided by financing activities	428,523	196,638
Net increase in cash and cash equivalents	10,295	13,048
Cash and cash equivalents, beginning of period	11,818	11,563
Cash and cash equivalents, end of period	$ 22,113	$ 24,611
Supplemental cash flow information:		
Cash paid for interest	$ 31,238	$ 29,470
Non-cash investing activity:		
Asset retirement obligations, net	$ 25,328	$ 9,855

See accompanying notes to consolidated financial statements

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, we own properties and oil and natural gas reserves primarily located in nine operating areas:

- the Permian Basin in West Texas and New Mexico;
- the Green River Basin in Wyoming;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Gulf Coast Basin in Texas and Mississippi;
- the Piceance Basin in Colorado;
- 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 and Series B preferred units are also listed on the NASDAQ under the symbols "VNRAP" and "VNRBP," 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, 2013, from the audited financial statements contained in our 2013 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 2013 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 June 30, 2014, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2013 Annual Report.

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of June 30, 2014 and December 31, 2013 and for the three and six months ended June 30, 2014 and 2013 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, 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 six months ended June 30, 2014 or 2013.

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 Pronouncements Issued But Not Yet Adopted:

In May 2014, the FASB issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU No. 2014-09”), which amends the FASB ASC by adding new FASB ASC Topic 606, Revenue from Contracts with Customers, and superseding the revenue recognition requirements in FASB ASC 605, Revenue Recognition, and in most industry-specific topics. ASU No. 2014-09 provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. ASU No. 2014-09 becomes effective at the beginning of 2017. We are still evaluating the impact of ASU No. 2014-09 on our financial position or results of operations.

(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

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 $549.1 million in cash. We refer to this acquisition as the “Pinedale Acquisition.” The purchase price is subject to additional customary post-closing adjustments to be determined based on an effective date of October 1, 2013. 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	$	593,695
Inventory		244
Asset retirement obligations		(12,404)
Imbalance liabilities		(209)
Other		(124)
Total fair value of assets and liabilities acquired		581,202
Fair value of consideration transferred		549,088
Gain on acquisition	$	32,114

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 $9.6 million paid to Marathon Oil Company. The cash consideration was funded with borrowings under our existing Reserve-Based Credit Facility (as defined below) and is subject to customary final post-closing adjustments to be determined based on an effective date of January 1, 2014.

During the six months ended June 30, 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 $4.2 million.

2013 Acquisitions

On April 1, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties located in the Permian Basin of Southeastern New Mexico and West Texas for an adjusted purchase price of $266.2 million. This acquisition had an effective date of January 1, 2013.

On June 28, 2013, we completed the acquisition of certain natural gas, oil and NGLs properties located in the Permian Basin in Texas and the San Juan and D-J Basins in Colorado with an effective date of July 1, 2013 for an adjusted purchase price of $29.9 million. The consideration for this acquisition was paid in common equity by issuing 1,075,000 VNR common units, at an agreed price of $27.65 per common unit, valued for financial reporting purposes at the closing price of $27.90 at the closing date of the acquisition.

We also completed other acquisitions during 2013 including the acquisition of additional working interests in certain acquired properties for an aggregate adjusted purchase price of $2.5 million.

The following presents the values assigned to the net assets acquired in our 2013 acquisitions:

Fair value of assets and liabilities acquired		**(in thousands)**
Oil and natural gas properties	$	317,573
Inventory		899
Asset retirement obligations		(11,381)
Oil and natural gas revenue payable and imbalance liabilities		(2,843)
Total fair value of assets and liabilities acquired		304,248
Fair value of consideration transferred		298,657
Gain on acquisition	$	5,591

Pro Forma Operating Results

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the three and six months ended June 30, 2014 and 2013 to show the effect on our consolidated results of operations as if our acquisitions completed in 2014 had occurred on January 1, 2013, and as if our acquisitions completed during 2013 had occurred on January 1, 2012.

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 and 2013, 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, (iii) interest expense on additional borrowings necessary to finance the acquisitions, and (iv) common units issued in the acquisition of properties completed on June 28, 2013. The gain on acquisition of oil and natural gas properties was excluded from the pro forma results for the six months ended June 30, 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total revenues	$ 123,373	$ 221,151	$ 235,540	$ 331,800
Net income (loss) attributable to Common and Class B unitholders	$ (9,690)	$ 86,868	$ (26,599)	$ 67,861
Net income (loss) per unit:				
Common & Class B units – basic and diluted	$ (0.12)	$ 1.20	$ (0.33)	$ 0.98

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Pinedale Acquisition				
Revenues	$ 39,575	$ —	$ 69,216	$ —
Excess of revenues over direct operating expenses	$ 30,196	$ —	$ 53,286	$ —
All other acquisitions				
Revenues	$ 17,212	$ 10,800	$ 32,047	$ 10,800
Excess of revenues over direct operating expenses	$ 11,186	$ 7,425	$ 20,910	$ 7,425

3. Long-Term Debt

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

Description	Interest Rate	Maturity Date	Amount Outstanding June 30, 2014	Amount Outstanding December 31, 2013
			(in thousands)	
Senior Secured Reserve-Based Credit Facility	Variable (1)	April 16, 2018	$ 725,000	$ 460,000
Senior Notes	7.875% (2)	April 1, 2020	550,000	550,000
			$ 1,275,000	$ 1,010,000
Unamortized discount on Senior Notes			(1,989)	(2,121)
Total long-term debt			$ 1,273,011	$ 1,007,879

(1) Variable interest rate was 1.90% and 1.92% at June 30, 2014 and December 31, 2013, respectively.
(2) Effective interest rate was 8.0%.

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 $1.525 billion (the "Reserve-Based Credit Facility"). As of June 30, 2014, there were $725.0 million of outstanding borrowings and $797.2 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $2.8 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 June 30, 2014, the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

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, limit 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 June 30, 2014, we were in compliance with all of our debt covenants.

Our Reserve-Based Credit Facility allows us to enter into commodity price hedge positions establishing certain minimum fixed prices for anticipated future production. See Note 4. *Price and Interest Rate Risk Management Activities* for further discussion.

Letters of Credit

At June 30, 2014, we have unused irrevocable standby letters of credit of approximately $2.8 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

June 30, 2014, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $355.1 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.

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. During the six months ended June 30, 2014, our derivative transactions included fixed-price swaps, basis swap contracts, collars, three-way collars, swaptions, call options sold, put options sold and range bonus accumulators.

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.

As of June 30, 2014, we had open commodity derivative contracts covering our anticipated future production as follows:

Fixed-Price Swaps

	Gas		Oil		NGLs	
Contract Period	**MMBtu**	**Weighted Average Fixed Price**	**Bbls**	**Weighted Average WTI Price**	**Bbls**	**Weighted Average Fixed Price**
July 1, 2014 – December 31, 2014	35,450,360	$ 4.42	915,400	$ 90.83	138,000	$ 40.87
January 1, 2015 – December 31, 2015	69,532,500	$ 4.39	692,000	$ 91.18	91,250	$ 42.00
January 1, 2016 – December 31, 2016	53,253,000	$ 4.48	146,400	$ 89.98	—	$ —
January 1, 2017 – December 31, 2017	25,852,000	$ 4.32	73,000	$ 86.60	—	$ —

Swaptions and Call Options Sold

Calls were sold or options were provided to counterparties under swaption agreements to extend the swap into subsequent years as follows:

	Oil	
Contract Period	**Bbls**	**Weighted Average Fixed Price**
July 1, 2014 – December 31, 2014	248,400	$ 102.41
January 1, 2015 – December 31, 2015	598,945	$ 104.32
January 1, 2016 – December 31, 2016	622,200	$ 125.00

Basis Swaps

Contract Period	Gas		
	MMBtu	Weighted Avg. Basis Differential ($/MMBtu)	Pricing Index
July 1, 2014 – December 31, 2014	14,720,000	$ (0.20)	Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential
January 1, 2015 – December 31, 2015	29,200,000	$ (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

Contract Period	Oil		
	Bbls	Weighted Avg. Basis Differential ($/Bbl)	Pricing Index
July 1, 2014 – December 31, 2014	294,400	$ (0.84)	WTI Midland and WTI Cushing Basis Differential
July 1, 2014 – December 31, 2014	165,600	$ (1.05)	West Texas Sour and WTI Cushing Basis Differential
July 1, 2014 – December 31, 2014	92,000	$ (3.95)	Light Louisiana Sweet Crude and Brent Basis Differential
January 1, 2015 – December 31, 2015	365,000	$ (0.90)	WTI Midland and WTI Cushing Basis Differential

Three-Way Collars

Contract Period	Gas			
	MMBtu	Floor	Ceiling	Put Sold
July 1, 2014 – December 31, 2014	1,840,000	$ 4.21	$ 5.00	$ 3.50

Contract Period	Oil			
	Bbls	Floor	Ceiling	Put Sold
July 1, 2014 – December 31, 2014	653,200	$ 93.52	$ 101.29	$ 72.54
January 1, 2015 – December 31, 2015	1,838,055	$ 91.99	$ 99.75	$ 74.16
January 1, 2016 – December 31, 2016	915,000	$ 90.00	$ 96.25	$ 70.00

Put Options Sold

Contract Period	Gas		Oil	
	MMBtu	Put Sold ($/MMBtu)	Bbls	Put Sold ($/Bbl)
July 1, 2014 – December 31, 2014	1,840,000	$ 3.50	36,800	$ 75.00
January 1, 2015 – December 31, 2015	7,300,000	$ 3.50	692,000	$ 72.36
January 1, 2016 – December 31, 2016	—	$ —	146,400	$ 75.00
January 1, 2017 – December 31, 2017	—	$ —	73,000	$ 75.00

Range Bonus Accumulators

	Gas			
Contract Period	MMBtu	Bonus	Range Ceiling	Range Floor
July 1, 2014 – December 31, 2014	736,000	$ 0.20	$ 4.75	$ 3.25
January 1, 2015 – December 31, 2015	1,460,000	$ 0.20	$ 4.75	$ 3.25

	Oil			
Contract Period	Bbls	Bonus	Range Ceiling	Range Floor
July 1, 2014 – December 31, 2014	460,000	$ 4.94	$ 103.20	$ 70.50

Interest Rate Swaps

As of June 30, 2014, we had open interest rate derivative contracts as follows (in thousands):

Period	Notional Amount	Fixed LIBOR Rates
July 1, 2014 to December 10, 2016	$ 20,000	2.17%
July 1, 2014 to October 31, 2016	$ 40,000	1.65%
July 1, 2014 to August 5, 2015 (1)	$ 30,000	2.25%
July 1, 2014 to August 6, 2016	$ 25,000	1.80%
July 1, 2014 to October 31, 2016	$ 20,000	1.78%
July 1, 2014 to September 23, 2016	$ 75,000	1.15%
July 1, 2014 to March 7, 2016	$ 75,000	1.08%
July 1, 2014 to September 7, 2016	$ 25,000	1.25%
July 1, 2014 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):

	June 30, 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	$ 62,496	$ (28,034)	$ 34,462
Total derivative instruments	$ 62,496	$ (28,034)	$ 34,462

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	$ (65,414)	$ 28,034	$ (37,380)
Interest rate derivative contracts	(6,345)	—	(6,345)
Total derivative instruments	$ (71,759)	$ 28,034	$ (43,725)

	December 31, 2013		
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	$ 107,307	$ (25,617)	$ 81,690
Interest rate derivative contracts	98	—	98
Total derivative instruments	$ 107,405	$ (25,617)	$ 81,788

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	$ (33,825)	$ 25,617	$ (8,208)
Interest rate derivative contracts	(6,869)	—	(6,869)
Total derivative instruments	$ (40,694)	$ 25,617	$ (15,077)

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 $62.5 million at June 30, 2014. 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 June 30, 2014. 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 six months ended June 30, 2014 and the year ended December 31, 2013 are as follows:

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
	(in thousands)	
Derivative asset at beginning of period, net	$ 66,711	$ 82,568
Fair value of derivatives acquired	(1,344)	—
Net gains (losses) on commodity and interest rate derivative contracts	(96,015)	11,160
Settlements		
Cash settlements paid (received) on matured commodity derivative contracts	19,380	(30,905)
Cash settlements paid on matured interest rate derivative contracts	2,005	3,888
Derivative asset (liability) at end of period, net	$ (9,263)	$ 66,711

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 June 30, 2014, the fair value of our Senior Notes was estimated to be $597.4 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, swaptions, call options sold, put options sold, 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, basis-swaps and swaptions 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):

	June 30, 2014			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 34,462	$ —	$ 34,462
Total derivative instruments	$ —	$ 34,462	$ —	$ 34,462
Liabilities:				
Commodity price derivative contracts	$ —	$ (35,626)	$ (1,754)	$ (37,380)
Interest rate derivative contracts	—	(6,345)		(6,345)
Total derivative instruments	$ —	$ (41,971)	$ (1,754)	$ (43,725)

	December 31, 2013			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 81,124	$ 566	$ 81,690
Interest rate derivative contracts	—	98	—	98
Total derivative instruments	$ —	$ 81,222	$ 566	$ 81,788
Liabilities:				
Commodity price derivative contracts	$ —	$ (8,208)	$ —	$ (8,208)
Interest rate derivative contracts	—	(6,869)	—	(6,869)
Total derivative instruments	$ —	$ (15,077)	$ —	$ (15,077)

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

	Unobservable Inputs (Level 3)	
	Six Months Ended June 30,	
	2014	2013
	(in thousands)	
Unobservable inputs, beginning of period	$ 566	$ (498)
Total gains (losses)	(1,606)	671
Settlements	(714)	1,200
Unobservable inputs, end of period	$ (1,754)	$ 1,373
Change in fair value included in earnings related to derivatives still held as of June 30, 2014 and 2013	$ (1,965)	$ 2,324

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. Any sharp prolonged decreases in the prices of oil and natural gas or any significant negative reserve adjustments from the October 1, 2013 assessment could change our estimates of the fair value of our 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 six months ended June 30, 2014 and year ended December 31, 2013, in connection with new wells drilled and wells acquired during the period, we incurred and recorded asset retirement obligations totaling $25.3 million and $11.7 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 ranging from 5.1% to 5.6%; and (4) the average inflation factor (2.4%). 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 June 30, 2014 and December 31, 2013 reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for the six months ended June 30, 2014 and year ended December 31, 2013 were as follows (in thousands):

	June 30, 2014	December 31, 2013
Asset retirement obligations, beginning of period	$ 87,967	$ 63,114
Liabilities added during the current period	25,328	11,738
Accretion expense	2,603	2,789
Retirements	(601)	(628)
Disposition of properties	(875)	—
Change in estimate	—	10,954
Asset retirement obligation, end of period	114,422	87,967
Less: current obligations	(7,647)	(5,759)
Long-term asset retirement obligation, end of period	$ 106,775	$ 82,208

7. Commitments and Contingencies

Transportation Demand Charges

As of June 30, 2014, we have contracts that provide firm transportation capacity on pipeline systems. The remaining terms on these contracts range from one to six 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 June 30, 2014. 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.

	(in thousands)
July 1, 2014 - December 31, 2014	$ 5,300
2015	7,912
2016	5,530
2017	3,978
2018	3,398
Thereafter	3,404
Total	$ 29,522

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

Preferred Units

Preferred units represent preferred equity company interests. As of June 30, 2014, preferred units issued and outstanding include our 7.875% Series A Cumulative Redeemable Perpetual Preferred Units ("Series A Preferred Units") and our 7.625% Series B Cumulative Redeemable Perpetual Preferred Units ("Series B Preferred Units") (collectively the "Preferred Units").

The 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, in connection with a change of control. We may redeem the Series A Preferred Units at any time on or after June 15, 2023 and we may redeem our Series B Preferred Units at any time on or after April 15, 2024. The 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. We may also redeem the Preferred Units in the event of a change of control. Holders of the 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 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.

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 Preferred Units have no participation rights and accordingly are excluded from the computation of basic net income per unit.

For the three and six months ended June 30, 2014, 485,038 unvested phantom units granted to officers, board members and employees under the VNR LTIP have been excluded in the computation of net income per common and Class B unit as they had no dilutive effect. For the three and six months ended June 30, 2013, 561,934 unvested phantom units granted to officers, board members and employees under the VNR LTIP date have been excluded in the computation of net income per common and Class B unit as they had no dilutive effect.

In accordance with ASC Topic 260, dual presentation of basic and diluted net income per common and Class B unit has been presented in the Consolidated Statements of Operations for the six months ended June 30, 2014 and 2013 including each class of units issued and outstanding during the respective periods: common units and Class B units. Net income attributable to common and Class B unitholders per unit is allocated to the common units and the Class B units on an equal basis.

Distributions Declared

The 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 Preferred Unit and a monthly rate of 7.625% per annum of the liquidation preference of $25.00 per Series B 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 July 16, 2014, our board of directors declared a cash distribution on the Preferred Units and common and Class B units attributable to the month of June 2014. See Note 11. *Subsequent Events* for further discussion.

	Cash Distributions			
Distribution	**Per Unit**	**Declared Date**	**Record Date**	**Payment Date**
2014				
Second Quarter				
May	$ 0.21	June 24, 2014	July 1, 2014	July 15, 2014
April	$ 0.21	May 20, 2014	June 2, 2014	June 13, 2014
First Quarter				
March	$ 0.21	April 17, 2014	May 1, 2014	May 15, 2014
February	$ 0.21	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
November	$ 0.2075	December 17, 2013	January 2, 2014	January 15, 2014
October	$ 0.2075	November 19, 2013	December 2, 2013	December 13, 2013
Third Quarter				
September	$ 0.2075	October 21, 2013	November 1, 2013	November 14, 2013
August	$ 0.2075	September 12, 2013	October 1, 2013	October 15, 2013
July	$ 0.2075	August 20, 2013	September 3, 2013	September 13, 2013
Second Quarter				
June	$ 0.2050	July 18, 2013	August 1, 2013	August 14, 2013
May	$ 0.2050	June 20, 2013	July 1, 2013	July 15, 2013
April	$ 0.2050	April 30, 2013	June 3, 2013	June 14, 2013
First Quarter				
March	$ 0.2025	April 19, 2013	May 1, 2013	May 15, 2013
February	$ 0.2025	March 21, 2013	April 1, 2013	April 12, 2013
January	$ 0.2025	February 18, 2013	March 1, 2013	March 15, 2013
2012				
Fourth Quarter				
December	$ 0.2025	January 25, 2013	February 4, 2013	February 14, 2013

9. Unit-Based Compensation

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. Each of the four components will be weighted equally in calculating the respective executive officer’s annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two (2) times the executive’s respective annual base salary. As of June 30, 2014, an accrued liability was recognized and compensation expense of $0.6 million was recorded related to these arrangements, which was classified in the selling, general and administrative expenses line item in the Consolidated Statement of Operations.

In the event of the Company’s Change in Control, as defined in the Vanguard Natural Resources, LLC Long-Term Incentive Plan (“VNR LTIP”), the executives are entitled to certain change in control payments and benefits, consisting of: (i) an amount equal to two (2) times their then-current base salary and annual bonus and (ii) accelerated vesting of any outstanding restricted units, phantom units, or any other awards granted under the VNR LTIP held by the executives at the time of the change of control, with any settlement of these awards being made according to the terms of the VNR LTIP and the applicable individual award agreement.

The executives are entitled to severance payments and benefits upon certain qualifying terminations. Upon a termination by VNRH without “Cause” (as such term is defined in the Amended Agreements) or termination by either executive for “Good Reason” (as such term is defined in the Amended Agreements), the executive is entitled to (i) an amount equal to three (3) times the executive’s then-current base salary and (ii) accelerated vesting of any outstanding restricted units, phantom units or any other awards granted under the VNR LTIP held by the executives at the time of such termination, with any settlement of these awards being made according to the terms of the VNR LTIP. Upon an executive’s termination by “Disability” (as such term is defined in the Amended Agreements) or death, the executive is entitled to (a) an amount equal to one times the executive’s then-current base salary and (b) accelerated vesting of any outstanding restricted units, phantom units or any other awards granted under the VNR LTIP held by the executives at the time of such termination, with any settlement of these awards being made according to the terms of the VNR LTIP. As a condition to receiving any of the severance payments and benefits heretofore described, the terminated executive (or his legal representative, as applicable) must execute and not revoke a customary severance and release agreement, including a waiver of all claims.

The Amended Agreements also provide that the executives are eligible to participate in the benefit programs generally available to senior executives of VNRH. The Amended Agreements also contain standard non-competition, non-solicitation and confidentiality provisions.

Restricted and Phantom Units

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. Each of the executives is eligible to receive annual equity-based compensation awards having an aggregate fair market value equal to the executive’s then-current annual base salary times a set multiplier, which such multiplier is five (5) times in the case of Mr. Smith, three and a half (3.5) times in the case of Mr. Robert, and two and three-quarters (2.75) times in the case of Mr. Pence.

The restricted units 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. The restricted units include a tandem grant of distribution equivalent rights (“DERs”), which entitle the executives to receive the value of any distributions made by us on our units generally with respect to the number of restricted units that the executives received pursuant to the grant. In the event the executive is terminated without Cause, or the executive resigns for Good Reason, or the executive is terminated due to his death or Disability, all unvested outstanding restricted units shall receive accelerated vesting. If the executive is terminated for Cause, all unvested restricted units are forfeited. Upon the occurrence of a Change of Control, all unvested outstanding restricted units shall receive accelerated vesting.

The phantom units are also 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. The phantom units include a tandem grant of DERs, which entitle the executives to receive the value of any distributions made by the Company on its units generally with respect to the number of phantom units that the executives received pursuant to the grant. In the event the executive is terminated without Cause, or the executive resigns for Good Reason, or the executive is terminated due to his death or Disability, all unvested outstanding phantom units shall receive accelerated vesting. If the executive is terminated for Cause, all unvested restricted units are forfeited. Upon the occurrence of a Change of Control, all unvested outstanding restricted units shall receive accelerated vesting.

The restricted units and the phantom units are subject to all the terms and conditions of the VNR LTIP as well as the individual award agreements which govern the awards. Neither the restricted units nor the phantom units are transferable, other than by will or the laws of descent and distribution. The Company shall withhold from the settlement or payment of the awards, as applicable, any amounts or units necessary to satisfy the Company's withholding obligations.

On January 1, 2014, the executives were granted a total of 182,377 restricted units in accordance with the Amended Agreements.

During the six months ended June 30, 2014, our three independent board members were granted a total of 13,137 restricted units which will vest one year from the date of grant. In addition, VNR employees were granted a total of 66,150 restricted units under the VNR LTIP which will vest three years from the date of grant.

As of June 30, 2014, an accrued liability of $1.1 million has been recorded related to phantom units granted to executive officers, board members and employees and non-cash unit-based compensation expense of $0.7 million has been recognized in the selling, general and administrative expense line item in the Consolidated Statements of Operations for each of the three months ended June 30, 2014 and 2013, and $1.1 million and $1.7 million for the six months ended June 30, 2014 and 2013, respectively.

Non-Vested Restricted Unit Grants

Historically, we have granted restricted common units to employees and board members as partial consideration for services to be performed and have accounted for these grants under ASC Topic 718, "*Compensation-Stock Compensation*." The fair value of restricted units issued is determined based on the fair market value of common units on the date of the grant. This value is amortized over the vesting period as referenced above. A summary of the status of the non-vested units as of June 30, 2014 is presented below:

	Number of Non-vested Restricted Units	Weighted Average Grant Date Fair Value
Non-vested restricted units at December 31, 2013	248,611	$ 28.57
Granted	261,664	$ 29.65
Forfeited	(1,000)	$ 29.19
Vested	(69,369)	$ 28.88
Non-vested restricted units at June 30, 2014	439,906	$ 29.17

At June 30, 2014, there was approximately $10.4 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.7 years.

Our Consolidated Statements of Operations reflect non-cash compensation of $2.1 million and $1.8 million in the selling, general and administrative expenses line item for the three months ended June 30, 2014 and 2013, respectively, and $5.0 million and $3.5 million for the six months ended June 30, 2014 and 2013, respectively.

10. Shelf Registration Statement

We have registered an indeterminate amount of Series A Preferred Units, Series B 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 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 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 $500.0 million, and (ii) our Series A Preferred Units having an aggregate offering price of up to $250.0 million. The common units and Series A Preferred Units to be sold under the equity distribution agreement are registered under our existing Shelf Registration Statement. During the six months ended 2014, total net proceeds received under the equity distribution agreement were approximately $100.4 million, after commissions and fees, from the sales of 3,323,411 common units and $0.7 million, after commissions and fees, from the sales of 25,734 Series A Preferred Units.

Preferred Unit Equity Offering

On March 11, 2014, we completed a public offering of 7,000,000 7.625% Series B Preferred Units at a price of $25.00 per unit. Offers were made pursuant to a prospectus supplement to the Shelf Registration Statement. We received proceeds of approximately $169.3 million from this offering, after deducting discounts of $5.5 million and offering costs of $0.2 million. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

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

Distributions

On July 16, 2014, our board of directors declared a cash distribution for our common and Class B unitholders attributable to the month of June 2014 of $0.21 per common and Class B unit ($2.52 on an annualized basis) expected to be paid on August 14, 2014 to Vanguard unitholders of record on August 1, 2014.

Also on July 16, 2014, our board of directors declared a cash distribution for our preferred unitholders of $0.1641 per Series A Preferred Unit and $0.15885 per Series B Preferred Unit to be paid on August 15, 2014 to Vanguard preferred unitholders of record on August 1, 2014.

Acquisition

On July 30 2014, we entered into a purchase and sale agreement to acquire natural gas and oil properties in North Louisiana and East Texas for a purchase price of $278.0 million. The effective date of the acquisition is June 1, 2014 and we anticipate closing on or before October 1, 2014. We intend to fund this acquisition with borrowings under our existing reserve-based credit facility.

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 six months ended June 30, 2014 and 2013. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Vanguard in conjunction with our 2013 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, increasing our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, we own properties and oil and natural gas reserves primarily located in nine operating areas:

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

As of June 30, 2014, based on internal reserve estimates, our total estimated proved reserves were 1,817 Bcfe, of which approximately 16% were oil reserves, 65% were natural gas reserves and 19% were NGLs reserves. Of these total estimated proved reserves, approximately 66%, or 1,193 Bcfe, were classified as proved developed. Also, at June 30, 2014, we owned working interests in 9,695 gross (2,807 net) productive wells. Our operated wells accounted for approximately 32% of our total estimated proved reserves at June 30, 2014. Our average net daily production for the six months ended June 30, 2014 and the year ended December 31, 2013 was 292 MMcfe/day and 213 MMcfe/day, respectively. We have interests in approximately 862,808 gross undeveloped acres surrounding our existing wells. As of June 30, 2014, based on internal reserve estimates, approximately 34%, or 624 Bcfe, of our estimated proved reserves were attributable to our interests in undeveloped acreage.

Recent Developments

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 a net cash consideration of $9.6 million paid to Marathon Oil Company. The cash consideration was funded with borrowings under our existing Reserve-Based Credit Facility and is subject to customary final post-closing adjustments to be determined based on an effective date of January 1, 2014.

On July 30, 2014, we entered into a purchase and sale agreement to acquire natural gas and oil properties in North Louisiana and East Texas for a purchase price of $278.0 million. The effective date of the acquisition is June 1, 2014 and we anticipate closing on or before October 1, 2014. We intend to fund this acquisition with borrowings under our existing reserve-based credit facility.

Business Environment

Price Volatility

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as commodity prices, access to capital, economic, political and regulatory developments, and competition from other sources of energy. Oil, natural gas and NGLs prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, natural gas or NGLs could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, our access to capital and our ability to pay cash distributions to our unitholders. We have mitigated the volatility on our cash flows by entering into oil and natural gas price derivative contracts through 2017 and NGLs price derivative contracts through 2015. These hedges are placed on a portion of our proved producing and a portion of our total anticipated production during this time frame. As oil, natural gas and NGLs prices fluctuate, we will recognize the change in fair value of our commodity derivative contracts as a non-cash item in our Consolidated Statements of Operations.

Production Decline

We also face the challenge of oil, natural gas and NGLs production declines. As a given well's initial reservoir pressures are depleted, oil, natural gas and NGLs production decreases, thus reducing our total reserves. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will maintain our focus on controlling costs to add reserves through drilling and acquisitions, as well as controlling the corresponding costs necessary to produce such reserves. During the six months ended June 30, 2014, we drilled 4 gross (1.5 net) operated wells and completed 5 gross (2.0 net) operated wells. We also participated in the drilling of 74 gross (9.8 net) non-operated wells and 99 gross (12.4 net) non-operated wells were completed during the first six months of 2014. Our ability to add production through drilling is dependent on our capital resources and can be limited by many factors, including the ability to timely obtain drilling permits and regulatory approvals as well as voluntary reductions in capital spending in a low commodity price environment. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of our production, which may have an adverse effect on our revenues, and as a result, cash available for distribution. In accordance with our business plan, we intend to invest the capital necessary to maintain our cash flow at existing levels over the long-term provided that it is economical to do so based on the commodity price environment. However, we cannot be certain that we will be able to issue our debt or equity securities on favorable terms, or at all, and we may be unable to refinance our borrowings when our credit facilities expire. Additionally, in the event of significant declines in commodity prices, the borrowing base under our Reserve-Based Credit Facility may be redetermined such that it could affect our ability to make distributions.

Impairment of Oil and Natural Gas Properties

We have elected to use the full cost method of accounting to report our oil and natural gas properties. Under this method, we capitalize the cost to acquire, explore for, and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of proved oil and natural gas properties may not exceed a “ceiling limit,” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling test write down.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write down would not impact cash flow from operating activities, but it could have a material adverse effect on our GAAP results of operations in the period incurred and would reduce our members’ equity.

In the current natural gas price environment, where the historical 12-month unweighted average of first-day-of-the-month historical price (the “12-month average price”) is less than the expected natural gas prices in future years, it is highly likely that an impairment would be recorded in the quarter in which we complete a natural gas asset acquisition. In accordance with the guidance contained within ASC Topic 805, “*Business Combinations,*” upon the acquisition of oil and natural gas properties, the company records an asset based on the measurement of the fair value of the properties acquired determined using forward oil and natural gas price curves at the acquisitions dates, which can have several price increases over the entire reserve life. As discussed above, capitalized oil and natural gas property costs are limited to a ceiling based on the present value of future net revenues, computed using a flat price for the entire reserve life equal to the historical 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. Furthermore, there is a risk that we will be required to record an impairment of our oil and natural gas properties if certain conditions, such as declining oil and natural gas prices, arise.

Results of Operations

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

	Three Months Ended June 30, (a)		Six Months Ended June 30, (a)	
	2014	**2013**	**2014**	**2013**
Revenues:				
Oil sales	$ 73,963	$ 69,701	$ 142,163	$ 128,217
Natural gas sales	69,806	36,010	133,348	63,534
NGLs sales	17,750	11,026	38,748	21,668
Oil, natural gas and NGLs sales	**161,519**	**116,737**	**314,259**	**213,419**
Net gains (losses) on commodity derivative contracts	(38,398)	58,595	(94,436)	29,320
Total revenues	**$ 123,121**	**$ 175,332**	**$ 219,823**	**$ 242,739**
Costs and expenses:				
Production:				
Lease operating expenses	$ 34,293	$ 26,509	$ 64,715	$ 50,682
Production and other taxes	16,529	9,964	31,563	19,307
Depreciation, depletion, amortization, and accretion	51,508	42,911	95,118	81,604
Selling, general and administrative expenses	5,733	5,125	10,899	9,946
Non-cash compensation	2,131	1,775	5,003	3,503
Total costs and expenses	**$ 110,194**	**$ 86,284**	**$ 207,298**	**$ 165,042**
Other income (expense):				
Interest expense	$ (16,549)	$ (15,963)	$ (32,808)	$ (31,401)
Net gains (losses) on interest rate derivative contracts	$ (1,121)	$ 2,412	$ (1,579)	$ 2,127
Gain on acquisition of oil and natural gas properties	$ —	$ 5,827	$ 32,114	$ 5,827
Other	$ 6	$ (23)	$ 131	$ 28

(a) During 2014 and 2013, 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 June 30, 2014 Compared to Three Months Ended June 30, 2013

Revenues

Oil, natural gas and NGLs sales increased $44.8 million to $161.5 million during the three months ended June 30, 2014 as compared to the same period in 2013. The key oil, natural gas and NGLs revenue measurements were as follows:

	Three Months Ended June 30, [a] 2014		2013		Percentage Increase / (Decrease)
Average realized prices, excluding hedges:					
Oil (Price/Bbl)	$	91.74	$	87.38	5 %
Natural Gas (Price/Mcf)	$	3.55	$	2.73	30 %
NGLs (Price/Bbl)	$	25.49	$	33.85	(25)%
Average realized prices, including hedges[b]:					
Oil (Price/Bbl)	$	84.40	$	86.31	(2)%
Natural Gas (Price/Mcf)	$	3.48	$	3.17	10 %
NGLs (Price/Bbl)	$	25.37	$	34.23	(26)%
Average NYMEX prices:					
Oil Price (Price/Bbl)	$	103.01	$	94.20	9 %
Natural Gas Price (Price/Mcf)	$	4.67	$	4.09	14 %
Total production volumes:					
Oil (MBbls)		806		798	1 %
Natural Gas (MMcf)		19,649		13,176	49 %
NGLs (MBbls)		696		326	114 %
Combined (MMcfe)		28,664		19,916	44 %
Average daily production volumes:					
Oil (Bbls/day)		8,860		8,765	1 %
Natural Gas (MMcf/day)		216		145	49 %
NGLs (Bbls/day)		7,652		3,579	114 %
Combined (MMcfe/day)		315		219	44 %

(a) During 2014 and 2013, 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 increase in oil, natural gas and NGLs sales during the three months ended June 30, 2014 compared to the same period in 2013 was due primarily to the increase in production from our acquisitions that were completed during 2014 and 2013. Natural gas revenues increased by 94% from $36.0 million in the second quarter of 2013 to $69.8 million in the second quarter of 2014 as a result of a 6,473 MMcf increase in our natural gas production volumes. In addition, we had a 30% increase in our average realized natural gas price, excluding hedges, from $2.73 per Mcf during the three months ended June 30, 2013 to $3.55 per Mcf in the same period of 2014. NGLs revenues also increased 61% during the second quarter of 2014 compared to the same period in 2013 primarily due to a 370 MBbls increase in NGLs production volumes, offset by a $8.36 per Bbl decrease in our average realized NGLs price, excluding hedges. Oil revenues increased slightly by 6%, from $69.7 million in the second quarter of 2013 to $74.0 million in the second quarter of 2014, as a result of higher oil production volumes and average realized oil price, excluding hedges. The increase in average realized oil price is primarily due to a higher average NYMEX price, which increased from $94.20 per Bbl in the second quarter of 2013 to $103.01 per Bbl in the second quarter of 2014. Overall, our total production for the three months ended June 30, 2014 increased by 44% on an Mcfe basis compared to the same period in 2013. On an Mcfe basis, crude oil, natural gas and NGLs accounted for 17%, 68% and 15%, respectively, of our production during the three months ended June 30, 2014 compared to crude oil, natural gas and NGLs of 24%, 66% and 10%, respectively, of our production during the same period in 2013.

Hedging and Price Risk Management Activities

During the three months ended June 30, 2014, we recognized a $38.4 million net loss on commodity derivative contracts. Cash settlements on matured commodity derivative contracts of $7.4 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 the counterparty paying us when commodity prices are below the hedged price and we 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 third-party transportation costs, gathering and compression fees, field personnel and other customary charges. Lease operating expenses increased by $7.8 million to $34.3 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013, of which $5.8 million related to increased lease operating expenses for oil and natural gas properties acquired during 2013 and 2014 and $2.0 million related to increased maintenance and repair expenses on existing and newly drilled 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/county and are based on the value of our reserves. Production and other taxes increased by $6.6 million for the three months ended June 30, 2014 as compared to the same period in 2013 primarily due to higher wellhead revenues as a result of the acquisitions completed during 2013 and 2014. As a percentage of wellhead revenues, production, severance and ad valorem taxes increased from 8.5% for the three months ended June 30, 2013 to 10.2% for the three months ended June 30, 2014. The percentage was lower during the three months ended June 30, 2013 primarily due to an accrued refund from the state of Texas for overpaid severance taxes on oil and natural gas properties in Texas pertaining to marketing cost reductions and tax reimbursements.

Depreciation, depletion, amortization, and accretion increased by approximately $8.6 million to $51.5 million for the three months ended June 30, 2014 from approximately $42.9 million for the three months ended June 30, 2013, primarily due to a higher depletion base associated with properties acquired during 2013 and 2014.

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 increased $0.6 million to $5.7 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013 primarily due to an increase in compensation related expenses for additional personnel attributable to our acquisitions. Non-cash compensation expense for the three months ended June 30, 2014 increased $0.4 million to $2.1 million as compared to the three months ended June 30, 2013, primarily as a result of the vesting of prior period units granted as well as additional restricted units granted to officers in 2014.

Other Income and Expense

Interest expense increased to $16.5 million for the three months ended June 30, 2014 from $16.0 million for the three months ended June 30, 2013 primarily due to a higher average outstanding debt under our Reserve-Based Credit Facility during the three months ended June 30, 2014 compared to the same period in 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Revenues

Oil, natural gas and NGLs sales increased $100.8 million to $314.3 million during the six months ended June 30, 2014 as compared to the same period in 2013. The key oil, natural gas and NGLs revenue measurements were as follows:

	Six Months Ended June 30,		Percentage Increase / (Decrease)
	2014[(a)]	2013[(a)]	
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$ 89.90	$ 84.19	7 %
Natural Gas (Price/Mcf)	$ 3.74	$ 2.52	48 %
NGLs (Price/Bbl)	$ 30.55	$ 37.17	(18)%
Average realized prices, including hedges [(b)]:			
Oil (Price/Bbl)	$ 84.36	$ 82.96	2 %
Natural Gas (Price/Mcf)	$ 3.45	$ 3.34	3 %
NGLs (Price/Bbl)	$ 30.10	$ 37.41	(20)%
Average NYMEX prices:			
Oil Price (Price/Bbl)	$ 100.89	$ 94.26	7 %
Natural Gas Price (Price/Mcf)	$ 4.86	$ 3.73	30 %
Total production volumes:			
Oil (MBbls)	1,581	1,523	4 %
Natural Gas (MMcf)	35,689	25,167	42 %
NGLs (MBbls)	1,268	583	118 %
Combined (MMcfe)	52,786	37,802	40 %
Average daily production volumes:			
Oil (Bbls/day)	8,737	8,414	4 %
Natural Gas (MMcf/day)	197	139	42 %
NGLs (Bbls/day)	7,007	3,220	118 %
Combined (MMcfe/day)	292	209	40 %

(a) During 2014 and 2013, 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 increase in oil, natural gas and NGLs sales during the six months ended June 30, 2014 compared to the same period in 2013 was due primarily to the increase in production from our acquisitions that were completed during 2013 and 2014. Natural gas revenues increased 110% from $63.5 million in the first six months of 2013 to $133.3 million in the first six months of 2014 as a result of a 10,522 MMcf increase in our natural gas production volumes and a $1.22 per Mcf, or 48%, increase in our average realized natural gas price, excluding hedges. NGLs revenues also increased 79% during the first six months of 2014 compared to the same period in 2013 primarily due to a 685 MBbls increase in NGLs production volumes, offset by a $6.62 per Bbl, or 18%, decrease in our average realized NGLs price, excluding hedges. Oil revenues increased 11%, from $128.2 million in the first six months of 2013 to $142.2 million in the first six months of 2014, as a result of a 58 MBbls increase in our oil production volumes and a $5.71 per Bbl, or 7%, increase in our average realized oil price, excluding hedges. This increase in average realized oil price was primarily due to a higher average NYMEX price, which increased from $94.26 per Bbl in the first six months of 2013 to $100.89 per Bbl in the first six months of 2014. Overall, our total production for the six months ended June 30, 2014 increased by 40% on an Mcfe basis compared to the same period in 2013. On an Mcfe basis, crude oil, natural gas, and NGLs accounted for 18%, 68% and 14%, respectively, of our production during the six months ended June 30, 2014 compared to crude oil, natural gas and NGLs of 24%, 67% and 9%, respectively, of our production during the same period in 2013.

Hedging and Price Risk Management Activities

During the six months ended June 30, 2014, we recognized $94.4 million in net losses on commodity derivative contracts. Cash payments on matured commodity derivative contracts of $19.4 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 third-party transportation costs, gathering and compression fees, field personnel and other customary charges. Lease operating expenses increased by $14.0 million to $64.7 million for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013, of which $12.4 million related to increased lease operating expenses for oil and natural gas properties acquired during 2013 and 2014 and $1.6 million related to increased maintenance and repair expenses on existing and newly drilled wells in the Arkoma Basin.

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/county and are based on the value of our reserves. Production and other taxes increased by $12.3 million for the six months ended June 30, 2014 as compared to the same period in 2013 primarily due to higher wellhead revenues as a result of the acquisitions completed in 2013 and 2014. As a percentage of wellhead revenues, production, severance and ad valorem taxes were 10.0% and 9.0% for the six months ended June 30, 2014 and 2013, respectively. The percentage was lower during the six months ended June 30, 2013 primarily due to lower tax rates in New Mexico and Texas on the oil and natural gas properties acquired during 2013 and an accrued refund from the state of Texas for overpaid severance taxes on oil and natural gas properties in Texas pertaining to marketing cost reductions and tax reimbursements.

Depreciation, depletion, amortization, and accretion increased by approximately $13.5 million to $95.1 million for the six months ended June 30, 2014 from approximately $81.6 million for the six months ended June 30, 2013 primarily due to a higher depletion base associated with properties acquired during 2013 and 2014.

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 increased $1.0 million to $10.9 million for the six months ended June 30, 2014 as compared to the same period in 2013 primarily due to an increase in compensation related expenses resulting from additional employees hired during 2013 and 2014. Non-cash compensation expense for the six months ended June 30, 2014 increased $1.5 million to $5.0 million as compared to the to the same period in 2013, primarily related to additional restricted and phantom unit grants in 2013 and 2014.

Other Income and Expense

Interest expense increased to $32.8 million for the six months ended June 30, 2014 from $31.4 million for the six months ended June 30, 2013 primarily due to a higher average outstanding debt under our Reserve-Based Credit Facility during the six months ended June 30, 2014 compared to the same period in 2013.

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 six months ended June 30, 2014. The comparable measurement for the acquisitions completed during 2013 resulted in goodwill of $1.5 million, which was immediately impaired and recorded as a loss, and a gain of $7.3 million, resulting in a net gain of $5.8 million for the six months ended June 30, 2013. The net gains and losses resulted from the increases and decreases 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 June 30, 2014, our critical accounting policies were consistent with those discussed in our 2013 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

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and the public debt and equity markets for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of oil and natural gas properties. We have in the past and expect in the future to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we 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 or debt, depending on market conditions. As of July 31, 2014, we had $807.2 million available to be borrowed under our Reserve-Based Credit Facility.

Our 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 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. Our current borrowing base is $1.525 billion and the next scheduled redetermination is in October 2014. Absent new acquisitions of oil and natural gas properties, if commodity prices decline in the future and banks lower their internal projections of oil, natural gas and NGLs prices, we will be subject to decreases in our borrowing base availability in the future.

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

Cash Flow from Operations

Net cash provided by operating activities was $154.9 million during the six months ended June 30, 2014, compared to $119.0 million during the six months ended June 30, 2013. Changes in working capital increased total cash flows by $1.0 million for the six months ended June 30, 2014 while it decreased total cash flows by $2.0 million in the same period in 2013. Contributing to the increase in working capital during 2014 was a $23.5 million increase 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 increase in working capital was offset by a $21.2 million increase in accounts receivable related to the timing of receipts from production from the acquisitions. 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 six months ended June 30, 2014 or 2013.

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, swaptions, 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 $573.2 million for the six months ended June 30, 2014, compared to $302.5 million during the same period in 2013. Cash used in investing activities during the first six months of 2014 primarily included $509.4 million for the acquisition of oil and natural gas properties, $61.5 million for the drilling and development of oil and natural gas properties and $3.7 million for deposits and prepayments related to the drilling and development of oil and natural gas properties, offset by $2.0 million in proceeds from the sale of certain leasehold interests in the Williston Basin. Net cash used in investing activities during the first six months of 2013 was primarily attributable to $270.5 million for the acquisition of oil and natural gas properties, $29.4 million for the drilling and development of oil and natural gas properties, $1.5 million for additions to property and equipment and $1.0 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 provided by financing activities was approximately $428.5 million for the six months ended June 30, 2014, compared to $196.6 million during the same period in 2013. Cash provided by financing activities included net proceeds from our public common unit and preferred unit offerings of $270.3 million and proceeds from borrowings under our long-term debt of $595.0 million. Additionally, cash used in financing activities during the six months ended June 30, 2014 included $330.0 million for the repayments of our long-term debt and $106.7 million cash paid to preferred, common and Class B unitholders in the form of distributions. Net cash provided by financing activities during the six months ended June 30, 2013 included net proceeds from our public common unit and preferred unit offerings of $529.0 million and proceeds from borrowings under our long-term debt of $388.5 million, offset by $638.5 million cash used in the repayments of our long-term debt, $80.3 million cash used in distributions to common and Class B unitholders and $2.1 million paid for financing costs.

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 $1.525 billion (the “Reserve-Based Credit Facility”). As of June 30, 2014, there were $725.0 million of outstanding borrowings and $797.2 million of borrowing capacity under the Reserve-Based Credit Facility, after consideration of a $2.8 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. Absent new acquisitions of oil and natural gas properties, if commodity prices decline and banks lower their internal projections of oil, natural gas and NGLs prices, we will be subject to decreases in our borrowing base availability in the future.

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 June 30, 2014, 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 June 30, 2014. 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 June 30, 2014, we have unused irrevocable standby letters of credit of approximately $2.8 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 June 30, 2014, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $355.1 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.

Off-Balance Sheet Arrangements

At June 30, 2014, 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 June 30, 2014 is provided in the following table (in thousands):

	Payments Due by Year						
	July 1, 2014 - December 31, 2014	2015	2016	2017	2018	After 2018	Total
Management base salaries	$ 693	$ 1,385	$ —	$ —	$ —	$ —	$ 2,078
Asset retirement obligations (1)	5,917	6,335	10,332	4,130	5,480	82,228	114,422
Derivative liabilities (2)	28,522	27,245	10,622	5,370	—	—	71,759
Reserve-Based Credit Facility (3)	—	—	—	—	725,000	—	725,000
Senior Notes and related interest	32,484	43,313	43,313	43,313	43,312	607,750	813,485
Operating leases	550	1,186	1,071	1,089	1,337	1,558	6,791
Development commitments (4)	50,599	9,387	—	—	—	—	59,986
Firm transportation agreements (5)	5,300	7,912	5,530	3,978	3,398	3,404	29,522
Total	$ 124,065	$ 96,763	$ 70,868	$ 57,880	$ 778,527	$ 694,940	$ 1,823,043

(1) Represents the discounted future plugging and abandonment costs of oil and natural gas wells and the decommissioning of ENP's Elk Basin gas plant. Please read Note 6. *Asset Retirement Obligations* of the Notes to the Consolidated Financial Statements for additional information regarding our asset retirement obligations.
(2) 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.
(3) 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.
(4) Represents authorized purchases for work in process.
(5) Represents 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.

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;
- 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 gains and losses on acquisitions of oil and natural gas properties;
- Texas margin taxes;
- 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; and
- Material transaction costs incurred on acquisitions and mergers.

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, 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.

However, 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 June 30, 2014, as compared to the three months ended June 30, 2013, Adjusted EBITDA increased 22%, from $80.3 million to $97.7 million. For the six months ended June 30, 2014, as compared to the six months ended June 30, 2013, Adjusted EBITDA increased 23%, from $152.7 million to $187.6 million. The following table presents a reconciliation of consolidated net income to Adjusted EBITDA (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$ (4,737)	$ 81,301	$ 10,383	$ 54,278
Plus:				
Interest expense	16,549	15,963	32,808	31,401
Depreciation, depletion, amortization, and accretion	51,508	42,911	95,118	81,604
Net (gains) losses on commodity derivative contracts	38,398	(58,595)	94,436	(29,320)
Cash settlements on matured commodity derivative contracts (a)(b)	(7,410)	4,971	(19,380)	18,721
Net (gains) losses on interest rate derivative contracts (c)	1,121	(2,412)	1,579	(2,127)
Gain on acquisition of oil and natural gas properties	—	(5,827)	(32,114)	(5,827)
Texas margin taxes	130	76	(281)	(241)
Compensation related items	2,131	1,775	5,003	3,503
Material transaction costs incurred on acquisitions	—	119	—	722
Adjusted EBITDA	$ 97,690	$ 80,282	$ 187,552	$ 152,714

(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.	$ —	$ 55	$ —	$ 109
(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.	$ 5,983	$ 7,504	$ 10,864	$ 15,428
(c) Includes settlements paid on interest rate derivatives	$ 1,015	$ 962	$ 2,005	$ 1,909

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.
- *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.
- *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. Currently, we are unable to hedge oil differentials in certain operating areas which exposes our cash flow to increased volatility in these areas. 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 June 30, 2014, the fair value of commodity derivative contracts was a liability of approximately $2.9 million, of which a net current liability of $22.8 million settles during the next twelve months.

The following table summarizes natural gas commodity derivative contracts in place at June 30, 2014:

	July 1, - December 31, 2014	Year 2015	Year 2016	Year 2017
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	35,450,360	69,532,500	53,253,000	25,852,000
Fixed Price ($/MMBtu)	$ 4.42	$ 4.39	$ 4.48	$ 4.32
Three-Way Collars:				
Notional Volume (MMBtu)	1,840,000	—	—	—
Floor Price ($/MMBtu)	$ 4.21	$ —	$ —	$ —
Ceiling Price ($/MMBtu)	$ 5.00	$ —	$ —	$ —
Put Sold ($/MMBtu)	$ 3.50	$ —	$ —	$ —
Total Gas Positions:				
Notional Volume (MMBtu)	37,290,360	69,532,500	53,253,000	25,852,000
Floor Price ($/MMBtu)	$ 4.41	$ 4.39	$ 4.48	$ 4.32

	July 1, - December 31, 2014	Year 2015	Year 2016	Year 2017
Oil Positions:				
Fixed-Price Swaps:				
Notional Volume (Bbls)	915,400	692,000	146,400	73,000
Fixed Price ($/Bbl)	$ 90.83	$ 91.18	$ 89.98	$ 86.60
Three-Way Collars:				
Notional Volume (Bbls)	653,200	1,838,055	915,000	—
Floor Price ($/Bbl)	$ 93.52	$ 91.99	$ 90.00	$ —
Ceiling Price ($/Bbl)	$ 101.29	$ 99.75	$ 96.25	$ —
Put Sold ($/Bbl)	$ 72.54	$ 74.16	$ 70.00	$ —
Total Oil Positions:				
Notional Volume (Bbls)	1,568,600	2,530,055	1,061,400	73,000
Floor Price ($/Bbl)	$ 91.95	$ 91.77	$ 90.00	$ 86.60

	July 1, - December 31, 2014	Year 2015
NGLs Positions:		
Fixed-Price Swaps:		
Mont Belvieu Ethane		
Notional Volume (Bbls)	35,678	—
Fixed Price ($/Bbl)	$ 11.03	$ —
Mont Belvieu Propane		
Notional Volume (Bbls)	72,671	91,250
Fixed Price ($/Bbl)	$ 40.50	$ 42.00
Mont Belvieu N. Butane		
Notional Volume (Bbls)	7,599	—
Fixed Price ($/Bbl)	$ 65.62	$ —
Mont Belvieu Isobutane		
Notional Volume (Bbls)	8,105	—
Fixed Price ($/Bbl)	$ 70.24	$ —
Mont Belvieu N. Gasoline		
Notional Volume (Bbls)	13,947	—
Fixed Price ($/Bbl)	$ 88.57	$ —
Total NGLs Positions:		
Notional Volume (Bbls)	138,000	91,250
Fixed Price ($/Bbl)	$ 40.87	$ 42.00

As of June 30, 2014, the Company sold the following put option contracts:

	July 1, - December 31, 2014	Year 2015	Year 2016	Year 2017
Gas Positions:				
Notional Volume (MMBtu)	1,840,000	7,300,000	—	—
Put Sold ($/MMBtu)	$ 3.50	$ 3.50	$ —	$ —
Oil Positions:				
Notional Volume (Bbls)	36,800	692,000	146,400	73,000
Put Sold ($/Bbl)	$ 75.00	$ 72.36	$ 75.00	$ 75.00

As of June 30, 2014, the Company had the following open range bonus accumulators contracts:

	July 1, - December 31, 2014	Year 2015
Gas Positions:		
Notional Volume (MMBtu)	736,000	1,460,000
Bonus ($/MMBtu)	$ 0.20	$ 0.20
Range Ceiling ($/MMBtu)	$ 4.75	$ 4.75
Range Floor ($/MMBtu)	$ 3.25	$ 3.25
Oil Positions:		
Notional Volume (Bbls)	460,000	—
Bonus ($/Bbl)	$ 4.94	$ —
Range Ceiling ($/Bbl)	$ 103.20	$ —
Range Floor ($/Bbl)	$ 70.50	$ —

As of June 30, 2014, the Company had the following open basis swap contracts:

	July 1, - December 31, 2014	Year 2015	Year 2016	Year 2017
Gas Positions:				
Northwest Rocky Mountain Pipeline and NYMEX Henry Hub Basis Differential				
Notional Volume (MMBtu)	14,720,000	29,200,000	18,300,000	10,950,000
Weighted-basis differential ($/MMBtu)	$ (0.20)	$ (0.28)	$ (0.24)	$ (0.22)

	July 1, - December 31, 2014	Year 2015
Oil Positions:		
WTI Midland and WTI Cushing Basis Differential		
Notional Volume (Bbls)	294,400	365,000
Weighted-basis differential ($/Bbl)	$ (0.84)	$ (0.90)
West Texas Sour and WTI Cushing Basis Differential		
Notional Volume (Bbls)	165,600	—
Weighted-basis differential ($/Bbl)	$ (1.05)	$ —
Light Louisiana Sweet Crude and Brent Basis Differential		
Notional Volume (Bbls)	92,000	—
Weighted-basis differential ($/Bbl)	$ (3.95)	$ —

Calls were sold or options provided to counterparties under swaption agreements to extend the swaps into subsequent years as follows:

	July 1, - December 31, 2014	Year 2015	Year 2016
Oil Positions:			
Notional Volume (Bbls)	248,400	598,945	622,200
Weighted Average Fixed Price ($/Bbl)	$ 102.41	$ 104.32	$ 125.00

Interest Rate Risks

At June 30, 2014, we had debt outstanding of $1.3 billion. The amount outstanding under our Reserve-Based Credit Facility at June 30, 2014 was $725.0 million 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 $0.06 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 June 30, 2014 (in thousands):

	July 1, - December 31, 2014	Year 2015(1)(2)	Year 2016
Weighted Average Notional Amount	$ 360,000	$ 344,959	$ 169,399
Weighted Average Fixed LIBOR Rate	1.30%	1.27%	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 June 30, 2014, 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):

	Current Assets	Long-Term Assets	Current Liabilities	Long-Term Liabilities	Total Amount Due From/(Owed To) Counterparty at June 30, 2014
Bank of America (A)	$ 398	$ 412	$ (730)	$ (592)	$ (512)
Barclays (A)	—	706	(3,872)	—	(3,166)
BBVA Compass (BBB)	—	—	(223)	—	(223)
BMO (A+)	—	—	(1,131)	(1,504)	(2,635)
CIBC (A+)	—	1,015	(1,622)	—	(607)
Citibank (A)	2,206	1,525	—	—	3,731
Comerica (A)	—	—	(496)	(455)	(951)
Credit Agricole (A)	—	—	(440)	(502)	(942)
Credit Suisse (A)	—	—	(811)	(341)	(1,152)
Fifth Third Bank (A-)	—	—	(1,628)	(629)	(2,257)
JP Morgan (A)	6,465	20,334	—	—	26,799
Morgan Stanley (A-)	—	—	(2,424)	(1,117)	(3,541)
Natixis (A)	363	—	(3,514)	(643)	(3,794)
RBC (AA-)	—	—	(2,513)	(231)	(2,744)
Shell (AA-)	—	—	(737)	(211)	(948)
Scotia Capital (A+)	—	701	(4,397)	(1,020)	(4,716)
Wells Fargo (AA-)	—	337	(11,256)	(686)	(11,605)
Total	$ 9,432	$ 25,030	$ (35,794)	$ (7,931)	$ (9,263)

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 $30.5 million at June 30, 2014.

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 June 30, 2014 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 second quarter of 2014 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 2013 Annual Report and to Part II-Item 1A-Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014. There have been no material changes to the risk factors set forth in our 2013 Annual Report and Part II-Item 1A-Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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

None.

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	Fourth Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC.	Form 8-K, filed March 11, 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 March 11, 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 March 11, 2014 (File No. 001-33756)
10.1	Sixth Amendment, dated April 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	Form 8-K, filed May 2, 2014 (File No. 001-33756)
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	Furnished herewith
101.SCH	XBRL Schema Document	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document	Furnished herewith
101.DEF	XBRL Definition Linkbase Document	Furnished herewith
101.LAB	XBRL Label Linkbase Document	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document	Furnished 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: August 5, 2014

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

EXHIBIT 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

I, Scott W. Smith, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2014

/s/ Scott W. Smith

Scott W. Smith

President and Chief Executive Officer
(Principal Executive Officer)
Vanguard Natural Resources, LLC

EXHIBIT 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

I, Richard A. Robert, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Vanguard Natural Resources, LLC (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2014

/s/ Richard A. Robert

Richard A. Robert

Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)
Vanguard Natural Resources, LLC

EXHIBIT 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**

In connection with the Quarterly Report of Vanguard Natural Resources, LLC (the “Company”) on Form 10-Q for the period ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Scott W. Smith, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Scott W. Smith
Scott W. Smith
President and Chief Executive Officer
(Principal Executive Officer)

August 5, 2014

EXHIBIT 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

In connection with the Quarterly Report of Vanguard Natural Resources, LLC (the “Company”) on Form 10-Q for the period ended June 30, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard A. Robert, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Richard A. Robert

Richard A. Robert

Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

August 5, 2014