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 September 30, 2012
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 November 1, 2012: 58,663,188.

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
BOE	= barrel of oil equivalent	MMBOE	= million barrels of oil equivalent
Btu	= British thermal unit	MMBtu	= million British thermal units
MBbls	= thousand barrels	MMcf	= million cubic feet
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”), VNR Holdings, LLC (“VNRH”), Vanguard Permian, LLC (“Vanguard Permian”), VNR Finance Corp. (“VNRF”), Encore Energy Partners Operating LLC 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, 2011 (the “2011 Annual Report”), our Quarterly Reports on Form 10-Q for the periods ended March 31, 2012 and June 30, 2012 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 September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Revenues:				
Oil, natural gas and NGLs sales	$ 78,871	$ 74,429	$ 228,029	$ 226,838
Loss on commodity cash flow hedges	—	(635)	—	(2,307)
Realized gain (loss) on commodity derivative contracts	318	1,902	(756)	4,474
Unrealized gain (loss) on commodity derivative contracts	(51,332)	109,639	9,243	68,625
Total revenues	27,857	185,335	236,516	297,630
Costs and expenses:				
Production:				
Lease operating expenses	19,514	14,230	54,754	41,683
Production and other taxes	7,053	7,693	21,164	21,319
Depreciation, depletion, amortization, and accretion	31,245	21,419	73,897	62,797
Impairment of oil and natural gas properties	18,029	—	18,029	—
Selling, general and administrative expenses	5,499	6,493	15,298	18,713
Total costs and expenses	81,340	49,835	183,142	144,512
Income (loss) from operations	(53,483)	135,500	53,374	153,118
Other income (expense):				
Interest expense	(12,389)	(7,509)	(27,548)	(21,137)
Realized loss on interest rate derivative contracts	(468)	(664)	(1,610)	(2,169)
Unrealized loss on interest rate derivative contracts	(2,463)	(1,939)	(5,507)	(1,641)
Net gain (loss) on acquisition of oil and natural gas properties	—	487	13,796	(383)
Other	76	70	191	76
Total other expense	(15,244)	(9,555)	(20,678)	(25,254)
Net income (loss)	(68,727)	125,945	32,696	127,864
Less:				
Net income attributable to non-controlling interest	—	50,061	—	50,593
Net income (loss) attributable to Vanguard unitholders	$ (68,727)	$ 75,884	$ 32,696	$ 77,271
Net income (loss) per Common and Class B units – basic	$ (1.29)	$ 2.51	$ 0.62	$ 2.56
Net income (loss) per Common and Class B units – diluted	$ (1.29)	$ 2.50	$ 0.62	$ 2.55
Weighted average units outstanding:				
Common units – basic	52,719	29,839	52,135	29,792
Common units – diluted	52,719	29,981	52,188	29,855
Class B units – basic & diluted	420	420	420	420

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income (loss)	$ (68,727)	$ 125,945	$ 32,696	$ 127,864
Net gains from derivative contracts:				
Reclassification adjustments for settlements	—	635	—	2,268
Other comprehensive income	—	635	—	2,268
Comprehensive income (loss)	$ (68,727)	$ 126,580	$ 32,696	$ 130,132

See accompanying notes to consolidated financial statements

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

	September 30, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 24,420	$ 2,851
Trade accounts receivable, net	54,131	48,046
Derivative assets	37,635	2,333
Other current assets	2,497	3,462
Total current assets	118,683	56,692
Oil and natural gas properties, at cost	1,767,497	1,549,821
Accumulated depletion	(290,466)	(331,836)
Oil and natural gas properties evaluated, net – full cost method	1,477,031	1,217,985
Other assets		
Goodwill	420,955	420,955
Derivative assets	46,077	1,105
Other assets	29,181	19,626
Total assets	$ 2,091,927	$ 1,716,363
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 6,861	$ 7,867
Affiliate	317	718
Accrued liabilities:		
Lease operating	6,042	5,828
Developmental capital	7,463	563
Interest	13,906	103
Production and other taxes	15,147	12,768
Derivative liabilities	4,279	12,774
Deferred swap premium liability	274	275
Oil and natural gas revenue payable	9,919	505
Distribution payable	11,761	—
Other	7,115	4,437
Total current liabilities	83,084	45,838
Long-term debt	570,000	771,000
Senior notes, net of discount	347,572	—
Derivative liabilities	11,230	20,553
Asset retirement obligations, net of current portion	43,363	34,776
Other long-term liabilities	3,443	275
Total liabilities	1,058,692	872,442
Commitments and contingencies (Note 8)		
Members' equity		
Members' capital, 58,661,188 common units issued and outstanding at September 30, 2012 and 48,320,104 at December 31, 2011	1,029,943	839,714
Class B units, 420,000 issued and outstanding at September 30, 2012 and December 31, 2011	3,292	4,207
Total members' equity	1,033,235	843,921
Total liabilities and members' equity	$ 2,091,927	$ 1,716,363

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2012 AND THE YEAR ENDED DECEMBER 31, 2011
(in thousands)
(Unaudited)

	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total Members' Equity
Balance at December 31, 2010	29,666	$ 318,597	420	$ 5,166	$ (3,032)	$ 548,662	$ 869,393
Distributions to members (Note 9)	—	(68,068)	—	(959)	—	—	(69,027)
Issuance of common units in connection with the ENP Merger and equity offering, net of merger costs of $2,503 and offering costs of $126	18,439	524,697	—	—	—	(527,326)	(2,629)
Unit-based compensation	215	2,425	—	—	—	—	2,425
Net income	—	62,063	—	—	—	26,067	88,130
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	3,032	—	3,032
ENP cash distribution to non-controlling interest	—	—	—	—	—	(47,403)	(47,403
Balance at December 31, 2011	48,320	$ 839,714	420	$ 4,207	$ —	$ —	$ 843,921
Distributions to members (Note 9)	—	(115,354)	—	(915)	—	—	(116,269)
Issuance of common units, net of offering costs of $989	12,149	322,021	—	—	—	—	322,021
Common units received in exchange for Appalachian Basin properties	(1,900)	(52,478)	—	—	—	—	(52,478)
Unit-based compensation	42	2,394	—	—	—	—	2,394
Options exercised	50	950	—	—	—	—	950
Net income	—	32,696	—	—	—	—	32,696
Balance at September 30, 2012	58,661	$ 1,029,943	420	$ 3,292	$ —	$ —	$ 1,033,235

See accompanying notes to consolidated financial statements

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

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating activities		
Net income	$ 32,696	$ 127,864
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	73,897	62,797
Impairment of oil and natural gas properties	18,029	—
Amortization of deferred financing costs	2,086	3,161
Amortization of debt discount	113	—
Deferred taxes	(139)	96
Unit-based compensation	2,394	1,821
Non-cash compensation associated with phantom units granted to officers	864	310
Amortization of premiums paid on derivative contracts	10,516	9,501
Amortization of value on derivative contracts acquired	14,096	154
Unrealized gains on commodity and interest rate derivative contracts	(3,736)	(66,984)
Net (gain) loss on acquisition of oil and natural gas properties	(13,796)	383
Changes in operating assets and liabilities:		
Trade accounts receivable	(985)	(12,350)
Payables to affiliates	(1,362)	793
Other current assets	388	(2,116)
Price risk management activities, net	(8,176)	(1,368)
Accounts payable and oil and natural gas revenue payable	8,741	1,244
Accrued expenses and other current liabilities	23,113	3,801
Other assets	422	4
Net cash provided by operating activities	159,161	129,111
Investing activities		
Additions to property and equipment	(392)	(650)
Additions to oil and natural gas properties	(40,285)	(23,729)
Acquisitions of oil and natural gas properties and derivative contracts	(452,114)	(183,659)
Deposits and prepayments of oil and natural gas properties	(4,761)	(666)
Proceeds from the sale of oil and natural gas properties	5,522	4,975
Net cash used in investing activities	(492,030)	(203,729)
Financing activities		
Proceeds from borrowings	549,000	393,000
Repayment of debt	(750,000)	(229,000)
Proceeds from Senior Notes, net of discount	347,459	—
Proceeds from equity offering, net	322,021	—
Distributions to members	(104,508)	(51,537)
Financing fees	(10,484)	(380)
Exercised options granted to officers	950	—
Prepaid offering costs	—	(88)
ENP distributions to non-controlling interest	—	(35,859)
Net cash provided by financing activities	354,438	76,136
Net increase in cash and cash equivalents	21,569	1,518
Cash and cash equivalents, beginning of period	2,851	1,828
Cash and cash equivalents, end of period	$ 24,420	$ 3,346
Supplemental cash flow information:		
Cash paid for interest	$ 11,480	$ 17,713
Non-cash investing and financing activities:		
Asset retirement obligations	$ 8,797	$ 4,661
Deferred swap premium	$ —	$ 9
Derivatives assumed in acquisition of oil and natural gas properties	$ —	$ 130
Common units received in exchange for Appalachian Basin properties	$ 52,478	$ —

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 six operating areas:

- the Permian Basin in West Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- Mississippi; and
- South Texas.

We previously owned properties and oil and natural gas reserves in the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee (the "Appalachian Basin"). On February 21, 2012, we and our 100% owned subsidiary, VNG, entered into a Unit Exchange Agreement with Majeed S. Nami Personal Endowment Trust and Majeed S. Nami Irrevocable Trust (collectively, the "Nami Parties") to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC, which entities controlled all of our ownership interests in oil and natural gas properties in the Appalachian Basin, in exchange for 1.9 million of our common units valued at the closing price of our common units of $27.62 per unit at March 30, 2012, or $52.5 million, with an effective date of January 1, 2012 (the "Unit Exchange"). The Nami Parties are controlled by or affiliated with Majeed S. Nami who was a founding unitholder when the Company went public in October of 2007. We completed this transaction on March 30, 2012 for non-cash consideration of $52.5 million, which was offset by post-closing adjustments of $1.4 million. This transaction was accounted for as a reduction to the full cost pool and no gain or loss was recognized because the assets transferred were not a significant portion of the full cost pool.

1. Summary of Significant Accounting Policies

The accompanying financial statements are unaudited and were prepared from our records. We derived the Consolidated Balance Sheet as of December 31, 2011, from the audited financial statements filed in our 2011 Annual Report. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles ("GAAP"). You should read this Quarterly Report on Form 10-Q along with our 2011 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. 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, members' equity or net cash flows.

As of September 30, 2012, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2011 Annual Report.

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of September 30, 2012 and December 31, 2011 and for the three and nine months ended September 30, 2012 and 2011 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.

(b) Oil and Natural Gas Properties:

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

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

Capitalized costs are limited to a ceiling based on the present value of future net revenues, computed using the 12-month unweighted average of first-day-of-the-month historical price (the "12-month average price"), discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is less than the total capitalized costs, we are required to write-down capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write downs are included in the Consolidated Statements of Operations as an impairment charge. Ceiling test calculations include the effects of the portion of oil and natural gas derivative contracts that have been recorded in other comprehensive income. We recorded a non-cash ceiling test impairment of oil and natural gas properties for the quarter ended September 30, 2012 of $18.0 million. The impairment was a result of a decline in natural gas prices at the measurement date, September 30, 2012. This impairment was calculated using the 12-month average price of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil.

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

(c) 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.

(d) Non-controlling Interest:

On December 31, 2010, we acquired (the "ENP Purchase") all of the member interests in Encore Energy Partners GP, LLC ("ENP GP"), the general partner of Encore Energy Partners LP ("ENP"), and 20,924,055 common units representing limited partnership interests in ENP (the "ENP Units"), together representing a 46.7% aggregate equity interest in ENP at the date of the ENP Purchase, from Denbury Resources Inc. Since the ENP Purchase, and prior to an internal reorganization whereby ENP GP and ENP were merged into VNG, we consolidated ENP as we had the ability to control the operating and financial decisions and policies of ENP through our ownership of ENP GP. As presented in the accompanying unaudited Consolidated Statements of Operations for the three and nine months ended September 30, 2011, "net income attributable to non-controlling interest" of $50.1 million and $50.6 million, respectively, represents ENP's results of operations attributable to third-party owners other than Vanguard.

On December 1, 2011, we acquired the remaining 53.4% of the ENP Units not held by us through a merger (the "ENP Merger") with one of our 100% owned subsidiaries. We refer to the ENP Purchase and ENP Merger collectively as the "ENP Acquisition."

2. Acquisitions

On March 9, 2012, we entered into a definitive agreement with a private seller for the acquisition of certain oil and natural gas properties located in Wyoming. We refer to this acquisition as the "Wyoming II Acquisition." We completed this acquisition on March 30, 2012 with an effective date of March 1, 2012 for an adjusted purchase price of $13.5 million. The purchase price was funded with borrowings under our Reserve-Based Credit Facility (defined in Note 3. *Debt*). In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at the acquisition date of the assets acquired in the Wyoming II Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in goodwill of $0.3 million, which was immediately impaired and recorded as a loss in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations.

On June 1, 2012, we entered into a purchase and sale agreement with Antero Resources LLC for the acquisition of natural gas and liquids properties in the Woodford Shale and Fayetteville Shale of the Arkoma Basin. We refer to this acquisition as the "Arkoma Basin Acquisition." This acquisition had an effective date of April 1, 2012 and the properties were purchased for an adjusted purchase price of $428.7 million, subject to customary post-closing adjustments to be determined. The purchase price was funded with borrowings under our Reserve-Based Credit Facility. Upon closing of this acquisition, we assumed natural gas swaps valued at $109.5 million on the closing date, which were restructured in July 2012 to cover 100% of the estimated natural gas production from existing producing wells in the acquired properties over the next five years.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at the acquisition date of the assets acquired in the Arkoma Basin Acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $14.1 million, as noted in the table below. The gain resulted primarily from changes in the value of derivative assets which were driven by corresponding natural gas prices and has been recognized in current period earnings and classified in other income and expense in the accompanying Consolidated Statements of Operations.

Fair value of assets and liabilities acquired:		(in thousands)
Oil and natural gas properties	$	345,668
Derivative assets		109,495
Asset retirement obligations		(8,920)
Oil and natural gas revenue payable and imbalance liabilities		(3,463)
Total fair value of assets and liabilities acquired		442,780
Fair value of consideration transferred		428,654
Gain on acquisition	$	14,126

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the three months ended September 30, 2011 and the nine months ended September 30, 2012 and 2011 to show the effect on our consolidated results of operations as if the Wyoming II and Arkoma Basin Acquisitions had occurred on January 1, 2011 and all of our acquisitions during 2011 as listed below had occurred on January 1, 2010. Pro forma results are not presented for the three months ended September 30, 2012 because all of the acquisitions occurred prior to the beginning of that period. For a complete description of these acquisitions please refer to footnote 2 of our consolidated financial statements contained in our 2011 Annual Report.

Acquisition	Closing Date
Newfield Acquisition	May 12, 2011
Permian Basin Acquisition I	July 29, 2011
Permian Basin Acquisition II	August 8, 2011
Wyoming I Acquisition	September 1, 2011
Gulf Coast Acquisition	August 31, 2011
North Dakota Acquisition	December 1, 2011
Parker Creek II Acquisition	December 22, 2011

The pro forma results reflect the results of combining our statement of operations with the results of operations from the oil and gas properties acquired, adjusted for (1) the assumption of asset retirement obligations and accretion expense for the properties acquired, (2) depletion expense applied to the adjusted basis of the properties acquired, (3) interest expense on additional borrowings necessary to finance the acquisitions and (4) interest expense on the Senior Notes (defined in Note 3. *Debt*), including the amortization of discount on bonds payable. As discussed in Note 3 of our consolidated financial statements, we used a portion of the net proceeds from the Senior Notes offering to repay all indebtedness outstanding under our Second Lien Term Loan (defined in Note 3. *Debt*) and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility. The repayment therefore resulted in an increase in the amount available for borrowing under our Reserve-Based Credit Facility. The pro forma results assume that the increase in borrowing capacity provides us available funding for the Arkoma Basin Acquisition. The unaudited pro forma results also reflect the impact of the Unit Exchange, including the elimination of the results of operations from the properties we previously owned in the Appalachian Basin and the receipt of the 1.9 million common units received as consideration for the exchange, as if it had occurred on January 1, 2011. The net gain (loss) on acquisition of oil and natural gas properties and material transaction costs related to the ENP Merger were excluded from the pro forma results for the three and nine months ended September 30, 2012 and 2011. Additionally, the pro forma results are adjusted for the elimination of our non-controlling interest in ENP for the three and nine months ended September 30, 2011 and the impact of additional common units issued in connection with the ENP Merger . 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 September 30,	Nine Months Ended September 30,	
	2011	2012	2011
Total revenues	$ 236,536	$ 312,408	$ 462,443
Net income (loss)	$ 147,186	$ 57,851	$ 196,923
Net income (loss) per unit:			
Common & Class B units – basic	$ 3.15	$ 1.10	$ 4.21
Common & Class B units – diluted	$ 3.14	$ 1.10	$ 4.21

The amount of revenues and excess of revenues over direct operating expenses that were eliminated to reflect the impact of the Unit Exchange in the pro forma results presented above are as follows:

	(in thousands)		
	Three Months Ended September 30,	Nine Months Ended September 30,	
	2011	2012	2011
Revenues	$ 4,886	$ 3,267	$ 15,357
Excess of revenues over direct operating expenses	$ 1,448	$ (400)	$ 4,783

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 (in thousands). Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Newfield Acquisition				
Revenues	$ 459	$ 424	$ 1,369	$ 733
Excess of revenues over direct operating expenses	$ (48)	$ 90	$ 279	$ 351
Permian Basin Acquisition I				
Revenues	$ 2,594	$ 2,554	$ 9,620	$ 2,554
Excess of revenues over direct operating expenses	$ 1,474	$ 1,189	$ 6,196	$ 1,189
Permian Basin Acquisition II				
Revenues	$ 489	$ 370	$ 1,353	$ 370
Excess of revenues over direct operating expenses	$ 246	$ 213	$ 728	$ 213
Wyoming I Acquisition				
Revenues	$ 660	$ 405	$ 3,260	$ 405
Excess of revenues over direct operating expenses	$ 467	$ 381	$ 1,992	$ 381
Gulf Coast Acquisition				
Revenues	$ 3,620	$ 841	$ 9,304	$ 841
Excess of revenues over direct operating expenses	$ 2,777	$ 770	$ 6,058	$ 770
North Dakota Acquisition				
Revenues	$ 676	$ —	$ 2,095	$ —
Excess of revenues over direct operating expenses	$ (80)	$ —	$ (75)	$ —
Parker Creek II Acquisition				
Revenues	$ 560	$ —	$ 1,644	$ —
Excess of revenues over direct operating expenses	$ 492	$ —	$ 1,443	$ —
Wyoming II Acquisition				
Revenues	$ 551	$ —	$ 1,047	$ —
Excess of revenues over direct operating expenses	$ 400	$ —	$ 782	$ —
Arkoma Basin Acquisition				
Revenues	$ 12,048	$ —	$ 12,048	$ —
Excess of revenues over direct operating expenses	$ 9,953	$ —	$ 9,953	$ —

3. Debt

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

Description	Interest Rate	Maturity Date	Amount Outstanding September 30, 2012	Amount Outstanding December 31, 2011
			(in thousands)	
Senior Secured Reserve-Based Credit Facility	Variable (1)	October 31, 2016	$ 570,000	$ 671,000
Second Lien Term Loan	Variable (2)	May 30, 2017	—	100,000
Senior Notes	7.875% (3)	April 1, 2020	350,000	—
			920,000	771,000
Unamortized discount on Senior Notes			(2,428)	—
Total debt			$ 917,572	$ 771,000

(1) Variable interest rate was 2.22% and 2.55% at September 30, 2012 and December 31, 2011, respectively.
(2) Variable interest rate was 5.8% at December 31, 2011.
(3) Effective interest rate is 8.0%.

Senior Secured Reserve-Based Credit Facility

On September 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the "Credit Agreement") with a maximum facility size of $1.5 billion (the "Reserve-Based Credit Facility") and an initial borrowing base of $765.0 million. The Credit Agreement provides for the (1) extension of the maturity date by five years to October 31, 2016, (2) increase in the number of lenders from eight to twenty, (3) increase in the percentage of future production that can be hedged, (4) increase in the permitted debt to EBITDA coverage ratio from 3.5x to 4.0x, (5) elimination of the required interest coverage ratio, (6) elimination of the ten percent liquidity requirement to pay distributions to unitholders, and (7) ability to incur unsecured debt. Borrowings from this Reserve-Based Credit Facility and the Second Lien Term Loan facility (as discussed below) were used to fully repay outstanding borrowings from ENP's senior secured revolving credit facility and Vanguard's $175.0 million term loan. In November 2011, we entered into the First Amendment to the Third Amended and Restated Credit Agreement, which included amendments to (a) specify the effective date of November 30, 2011, (b) allow us to use the proceeds from our Reserve-Based Credit Facility to refinance our debt under the Second Lien Term Loan facility, (c) include the current maturities under the Second Lien Term Loan in determining the consolidated current ratio, and (d) provide a cap on the amount of outstanding debt under the Second Lien Term Loan. Our obligations under the Reserve-Based Credit Facility are secured by mortgages on our oil and natural gas properties and other assets and are guaranteed by all of our operating subsidiaries. On March 30, 2012, the closing date of the Unit Exchange, our borrowing base was reduced to $740.0 million and was further reduced to $670.0 million in April 2012 as a result of the completion of our Senior Notes offering. On June 29, 2012, in connection with the closing of the Arkoma Basin Acquisition, we entered into the Second Amendment to the Third Amended and Restated Credit Agreement (the "Second Amendment"). The Second Amendment increased the borrowing base to $975.0 million from $670.0 million and added two new lenders to the Reserve-Based Credit Facility.

On September 30, 2012 there were $570.0 million of outstanding borrowings and $405.0 million of borrowing capacity under the Reserve-Based Credit Facility.

On October 5, 2012, our borrowing base under the Reserve-Based Credit Facility was increased to $1.0 billion from $975.0 million pursuant to our semi-annual redetermination. On October 9, 2012, we completed a public offering of an additional $200.0 million aggregate principal amount of our senior unsecured notes. Our borrowing base was subsequently reduced to $960.0 million as a result of this offering. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility. Please see Note 12. *Subsequent Events* for further discussion.

Interest rates under the Reserve-Based Credit Facility are based on Euro-Dollars (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 September 30, 2012, 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 September 30, 2012, 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.

Second Lien Term Loan

On November 30, 2011, we entered into a $100.0 million senior secured second lien term loan facility (the "Second Lien Term Loan") with a maturity date of May 30, 2017. Borrowings under the Second Lien Term Loan were comprised entirely of Eurodollar Loans. Interest on borrowings under the Second Lien Term Loan accrued at a rate per annum equal to the sum of the applicable margin plus the Adjusted LIBOR Rate in effect on such day. In January 2012, we used a portion of the proceeds from our equity offering to repay $43.0 million of our outstanding debt under the Second Lien Term Loan. We paid the remaining outstanding debt of $57.0 million in April 2012 using the proceeds from our senior unsecured notes offering.

Senior Notes

On April 4, 2012, we and our 100% owned finance subsidiary, VNRF, completed a public offering of $350.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the "Senior Notes"), at a public offering price of 99.274%, resulting in aggregate net proceeds of $338.7 million, after deducting underwriting discounts and financing fees. The discount and financing fees will be amortized over the life of the Senior Notes. Such amortization is recorded in interest expense on the Consolidated Statements of Operations. We have 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 release under certain of the following circumstances: (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 September 30, 2012, based on the most restrictive covenants of the Indenture, the Company's cash balance and the borrowings available under the Reserve-Based Credit Facility, $280.0 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 103.93750% 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.

We used a portion of the net proceeds from this offering to repay all remaining indebtedness outstanding under our Second Lien Term Loan and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility.

As discussed above, in October 2012, we completed a public offering of an additional $200.0 million aggregate principal amount of our senior unsecured notes. Please see Note 12. *Subsequent Events* for further discussion.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our financing arrangements to hedge price risk associated with a portion of our oil and natural gas 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 over hedged volumes. Under fixed-priced commodity swap agreements, we receive a fixed price on a notional quantity in exchange for paying a variable price based on a market index. In addition, we sell calls, purchase puts or provide options to counterparties under swaption agreements to extend the swaps into subsequent years. Under put option agreements, we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. At settlement date, we receive the excess, if any, of the fixed floor over floating rate. We also enter into 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. Under collar contracts, we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor price on a notional quantity. Put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub, and collars are settled based on a market index selected by us at inception of the contract. We also may enter into 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 or a higher floor 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 of NYMEX West Texas Intermediate ("WTI") crude oil drops below the price of the short put. This allows us to settle for WTI market price 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. We also enter into fixed LIBOR interest rate swap agreements with certain counterparties that are lenders under our financing arrangements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Under ASC Topic 815, *"Derivatives and Hedging"* ("ASC Topic 815"), all derivative instruments are recorded on the accompanying Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) in the equity section of the Consolidated Balance Sheets to the extent the hedge is effective. Gains and losses on cash flow hedges included in accumulated other comprehensive income (loss) are reclassified to gains (losses) on commodity cash flow hedges or gains (losses) on interest rate derivative contracts in the period that the related production is delivered or the contract settles. The realized and unrealized gains (losses) on derivative contracts that do not qualify for hedge accounting treatment are recorded as gains (losses) on commodity derivative contracts or gains (losses) on interest rate derivative contracts in the accompanying Consolidated Statements of Operations.

We have elected not to designate our current portfolio of derivative contracts as hedges. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included as unrealized gains (losses) on commodity derivative contracts or gains (losses) on interest rate derivative contracts in the accompanying Consolidated Statements of Operations.

As of September 30, 2012, we had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas			Oil		
Contract Period	**MMBtu**		**Weighted Average Fixed Price**	**MBbls**		**Weighted Average WTI Price**
October 1, 2012 – December 31, 2012	7,240,584	$	5.15	369	$	91.35
January 1, 2013 – December 31, 2013	27,813,000	$	5.09	1,729	$	90.59
January 1, 2014 – December 31, 2014	20,587,725	$	5.07	1,414	$	89.91
January 1, 2015 – December 31, 2015	18,250,000	$	5.04	—	$	—
January 1, 2016 – December 31, 2016	16,470,000	$	5.04	—	$	—
January 1, 2017 – December 31, 2017	7,602,000	$	5.04	—	$	—

Swaptions

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

	Gas			Oil		
Contract Period	**MMBtu**		**Weighted Average Fixed Price**	**MBbls**		**Weighted Average Fixed Price**
October 1, 2012 - December 31, 2012	—		—	35	$	100.00
January 1, 2013 - December 31, 2013	—		—	196	$	100.73
January 1, 2014 - December 31, 2014	1,642,500	$	5.69	493	$	117.22
January 1, 2015 - December 31, 2015	—		—	508	$	105.98
January 1, 2016 - December 31, 2016	—		—	622	$	125.00

Basis Swaps

	Gas			Oil		
Contract Period	**MMBtu**		**Weighted Avg. Basis Differential (1)**	**MBbls**		**Weighted Avg. Basis Differential (2)**
October 1, 2012 – December 31, 2012	230,000	$	(0.32)	21	$	15.15
January 1, 2013 – December 31, 2013	912,500	$	(0.32)	84	$	9.60
January 1, 2014 – December 31, 2014	452,500	$	(0.32)	—	$	—

(1) Natural gas basis swap contracts represent a weighted average differential between prices against Rocky Mountains (CIGC) and NYMEX Henry Hub prices.
(2) Oil basis swap contracts represent a weighted average differential between prices against Light Louisiana Sweet Crude (LLS) and NYMEX WTI prices.

Collars

	Oil				
Contract Period	**MBbls**		**Floor**		**Ceiling**
October 1, 2012 - December 31, 2012	104	$	80.89	$	99.47
January 1, 2013 - December 31, 2013	82	$	88.89	$	107.34
January 1, 2014 - December 31, 2014	12	$	100.00	$	116.20

Three-Way Collars

Contract Period	Oil MBbls	Oil Floor	Oil Ceiling	Oil Put Sold
October 1, 2012 - December 31, 2012	216	$ 88.94	$ 104.02	$ 69.36
January 1, 2013 - December 31, 2013	876	$ 95.21	$ 107.94	$ 72.76
January 1, 2014 - December 31, 2014	566	$ 98.06	$ 108.86	$ 74.19
January 1, 2015 - December 31, 2015	194	$ 100.00	$ 124.53	$ 75.00

Puts

Contract Period	Gas MMBtu	Gas Weighted Average Fixed Price
October 1, 2012 – December 31, 2012	82,616	$ 6.76

We sold oil puts for 2013 on 378,400 barrels at a weighted average price of $60.47. Additionally, we sold oil puts on 114,250 barrels at a weighted average price of $65.00 for the balance of 2012 through 2013.

Put Spreads

Contract Period	Oil MBbls	Oil Floor	Oil Put Sold
January 1, 2015 – December 31, 2015	256	$ 100.00	$ 75.00

Interest Rate Swaps

We enter into interest rate swap agreements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate exposures to fixed interest rates.

As of September 30, 2012, we had open interest rate derivative contracts as follows (in thousands):

Period	Notional Amount	Fixed Libor Rates
October 1, 2012 to December 10, 2016	$ 20,000	2.17%
October 1, 2012 to October 31, 2016	$ 40,000	1.65%
October 1, 2012 to October 31, 2016	$ 20,000	1.78%
October 1, 2012 to March 7, 2016	$ 75,000	1.08%
October 1, 2012 to September 23, 2016	$ 75,000	1.15%
October 1, 2012 to August 6, 2016	$ 25,000	1.80%
October 1, 2012 to August 5, 2015 (1)	$ 30,000	2.25%
October 1, 2012 to September 7, 2016 (2)	$ 25,000	1.25%
Total	$ 310,000	

(1) On August 15, 2015, the counterparty has the option to extend the termination date of this contract for a notional amount of $30.0 million at 2.25% to August 5, 2018.

(2) On September 5, 2012, a counterparty exercised its option to put us into a $25,000 LIBOR swap at 1.25% for the period from September 7, 2012 to September 7, 2016.

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 summarizes the fair value of derivatives outstanding on a gross basis (in thousands):

	September 30, 2012	December 31, 2011
Assets:		
Commodity derivatives	$ 124,563	$ 42,504
Interest rate swaps	200	504
	$ 124,763	$ 43,008
Liabilities:		
Commodity derivatives	$ (44,769)	$ (66,129)
Interest rate swaps	(11,791)	(6,768)
	$ (56,560)	$ (72,897)

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. *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 $124.8 million at September 30, 2012.

We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments only with counterparties that are also lenders in our Reserve-Based Credit Facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis. 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 partially mitigated as of September 30, 2012.

Gain (Loss) on Derivatives

Gains and losses on derivatives that are not accounted for as cash flow hedges are reported on the accompanying Consolidated Statements of Operations in “realized or unrealized gain (loss) on commodity derivative contracts” and “realized or unrealized gain (loss) on interest rate derivative contracts.” Realized gains (losses) represent amounts related to the settlement of derivative instruments. Unrealized gains (losses) represent the change in fair value of the derivative instruments to be settled in the future and are non-cash items which fluctuate in value as commodity prices and interest rates change.

The following presents our reported gains and losses on derivative instruments (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Realized gains (losses):				
Commodity derivatives	$ 318	$ 1,902	$ (756)	$ 4,474
Interest rate swaps	(468)	(664)	(1,610)	(2,169)
	$ (150)	$ 1,238	$ (2,366)	$ 2,305
Unrealized gains (losses):				
Commodity derivatives	$ (51,332)	$ 109,639	$ 9,243	$ 68,625
Interest rate swaps	(2,463)	(1,939)	(5,507)	(1,641)
	$ (53,795)	$ 107,700	$ 3,736	$ 66,984
Net gains (losses):				
Commodity derivatives	$ (51,014)	$ 111,541	$ 8,487	$ 73,099
Interest rate swaps	(2,931)	(2,603)	(7,117)	(3,810)
	$ (53,945)	$ 108,938	$ 1,370	$ 69,289

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, 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. The carrying amounts of our Senior Notes approximate fair value because they approximate the amounts for which the Senior Notes traded in the secondary market at September 30, 2012. We consider this fair value estimate as a Level 1 input.

Our commodity derivative instruments consist of fixed-price swaps, basis swaps, swaptions, put options, NYMEX collars and three-way collars. We estimate the fair values of the 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, collars 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. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties' and our credit standing are used to discount future cash flows. We have classified the fair values of all of our derivative contracts as Level 2.

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

	September 30, 2012			
	Fair Value Measurements Using			Assets/Liabilities at Fair value
	Level 1	Level 2	Level 3	
Assets:				
Commodity price derivative contracts	$ —	$ 83,512	$ —	$ 83,512
Interest rate derivative contracts	—	200	—	200
Total derivative instruments	$ —	$ 83,712	$ —	$ 83,712
Liabilities:				
Commodity price derivative contracts	$ —	$ (3,718)	$ —	$ (3,718)
Interest rate derivative contracts	—	(11,791)	—	(11,791)
Total derivative instruments	$ —	$ (15,509)	$ —	$ (15,509)

	December 31, 2011			
	Fair Value Measurements Using			Assets/Liabilities at Fair value
	Level 1	Level 2	Level 3	
Assets:				
Commodity price derivative contracts	$ —	$ 3,438	$ —	$ 3,438
Interest rate derivative contracts	—	—	—	—
Total derivative instruments	$ —	$ 3,438	$ —	$ 3,438
Liabilities:				
Commodity price derivative contracts	$ —	$ (27,063)	$ —	$ (27,063)
Interest rate derivative contracts	—	(6,264)	—	(6,264)
Total derivative instruments	$ —	$ (33,327)	$ —	$ (33,327)

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 decreases in the prices of oil and natural gas or any significant negative reserve adjustments from the December 31, 2011 assessment could change our estimates of the fair value of our reporting unit and could result in an impairment charge.

Intangible assets with definite useful lives are amortized over their estimated useful lives. We evaluate the recoverability of intangible assets with definite useful lives whenever events or changes in circumstances indicate that the carrying value of the asset may not be fully recoverable. An impairment loss exists when the estimated undiscounted cash flows expected to result from the use of the asset and its eventual disposition are less than its carrying amount.

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

	September 30, 2012		
	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Assets:			
Goodwill	$ —	$ —	$ 420,955
Acquisitions of oil and natural gas properties	$ —	$ —	$ 360,306
Other intangible assets, net	$ —	$ 8,701	$ —

	December 31, 2011		
	Fair Value Measurements Using		
	Level 1	Level 2	Level 3
Assets:			
Goodwill	$ —	$ —	$ 420,955
Other intangible assets, net	$ —	$ 8,837	$ —

Our nonfinancial assets and liabilities, which are initially measured at fair value, are comprised primarily of asset retirement obligations and oil and natural gas properties acquired in business combination transactions. These assets and liabilities are recorded at fair value when 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. We utilize ASC Topic 805-10 to identify and record the fair value of assets and liabilities acquired in a business combination. During the nine month period ended September 30, 2012, we acquired oil and natural gas properties with a fair value of $360.3 million. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 6. *Asset Retirement Obligations*, in accordance with ASC Topic 410-20. 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 costs 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 between 4.8% and 5.5%; and (4) the 10-year average inflation factor (2.4%).

6. Asset Retirement Obligations

The asset retirement obligations as of September 30 reported on our Consolidated Balance Sheets and the changes in the asset retirement obligations for the nine months ended September 30, were as follows (in thousands):

	2012	2011
Asset retirement obligations at January 1,	$ 35,921	$ 30,202
Liabilities added during the current period	9,248	4,661
Accretion expense	914	609
Retirements	(451)	(90)
Total asset retirement obligations at September 30,	45,632	35,382
Less: current obligations	(2,269)	(1,018)
Long-term asset retirement obligation at September 30,	$ 43,363	$ 34,364

7. Related Party Transactions

As previously discussed, we owned oil and natural gas properties in the Appalachian Basin. On February 21, 2012, we and our 100% owned subsidiary, VNG, entered into the Unit Exchange with the Nami Parties to transfer our partnership interest in Trust Energy Company, LLC and Ariana Energy, LLC, which entities controlled all of our ownership interests in oil and natural gas properties in the Appalachian Basin, in exchange for 1.9 million of our common units valued at the closing price of our common units of $27.62 per unit at March 30, 2012, or $52.5 million, with an effective date of January 1, 2012. The Nami Parties are controlled by or affiliated with Majeed S. Nami who was a founding unitholder when the Company went public in October of 2007. We completed this transaction on March 30, 2012 for non-cash consideration of $52.5 million, which was offset by post-closing adjustments of $1.4 million.

Prior to the completion of the Unit Exchange, we relied on Vinland Energy Eastern, LLC ("Vinland") to execute our drilling program, operate our wells and gather our natural gas in the Appalachian Basin. We reimbursed Vinland $60.00 per well per month (in addition to normal third party operating costs) for operating our current natural gas and oil properties in the Appalachian Basin under a Management Services Agreement ("MSA") which costs were reflected in our lease operating expenses. Under a Gathering and Compression Agreement ("GCA"), Vinland received a $0.25 per Mcf transportation fee on existing wells drilled prior to December 31, 2006 and $0.55 per Mcf transportation fee on any new wells drilled after December 31, 2006 within the area of mutual interest or "AMI." In June 2010, we began discussions with Vinland regarding an amendment to the GCA to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and jointly operated on this basis, however, no formal agreement between us and Vinland was signed. Under the GCA, the transportation fee that we paid to Vinland only encompassed transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets applied. These transportation fees were outlined in the GCA and are reflected in our lease operating expenses. Costs incurred under the MSA were $0.5 million for the three months ended September 30, 2011, and $0.6 million and $1.4 million for the nine months ended September 30, 2012 and 2011, respectively. Costs incurred under the GCA were $0.5 million for the three months ended September 30, 2011, and $0.4 million and $1.4 million for the nine months ended September 30, 2012 and 2011, respectively. As a result of the Unit Exchange, the MSA and GCA were terminated.

8. Commitments and Contingencies

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 also currently a party to pending litigation related to the ENP Merger ("ENP Litigation") discussed below. 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.

On March 29, 2011, John O'Neal, a purported unitholder of ENP, filed a putative class action petition in the 125th Judicial District of Harris County, Texas on behalf of unitholders of ENP. Similar petitions were filed on April 4, 2011 by Jerry P. Morgan and on April 5, 2011 by Herbert F. Rower in other Harris County district courts. The *O'Neal*, *Morgan*, and *Rower* lawsuits were consolidated on June 5, 2011 as *John O'Neal v. Encore Energy Partners, L.P., et al*., Case Number 2011-19340, which is pending in the 125th Judicial District Court of Harris County. On July 28, 2011, Michael Gilas filed a class action petition in intervention. On July 26, 2011, the current plaintiffs in the consolidated *O'Neal* action filed an amended putative class action petition against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action petition and Gilas' petition in intervention both allege that the named defendants are (i) violating duties owed to ENP's public unitholders by, among other things, failing to properly value ENP and failing to protect against conflicts of interest or (ii) are aiding and abetting such breaches. Plaintiffs sought an injunction prohibiting the merger from going forward and compensatory damages if the merger was consummated. On October 3, 2011, the Court appointed Bull & Lifshitz, counsel for plaintiff-intervenor Gilas, as interim lead counsel on behalf of the putative class. On October 21, 2011, the court signed an order staying this lawsuit pending resolution of the Delaware State Court Action (defined below), subject to plaintiffs' right to seek to lift the stay for good cause. The defendants named in the Texas lawsuits intend to defend vigorously against them.

On April 5, 2011, Stephen Bushansky, a purported unitholder of ENP, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption *In re: Encore Energy Partners LP Unitholder Litigation*, C.A. No. 6347-VCP (the "Delaware State Court Action"). On December 28, 2011, those plaintiffs jointly filed their second amended consolidated class action complaint naming as defendants ENP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action complaint alleges, among other things, that defendants breached the partnership agreement by recommending a transaction that is not fair and reasonable. Plaintiffs seek compensatory damages. Vanguard has filed a motion to dismiss this lawsuit. On August 31, 2012, the Chancery Court entered an order granting Vanguard's motion to dismiss the complaint for failure to state a claim and dismissing the Delaware State Court Action with prejudice. On September 27, 2012, Plaintiffs in that matter filed a notice of their appeal of the dismissal.

On August 28, 2011, Herman Goldstein, a purported unitholder of ENP, filed a putative class action complaint against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard in the United States District Court for the Southern District of Texas on behalf of the unitholders of ENP. That lawsuit is captioned *Goldstein v. Encore Energy Partners LP. et al.*, United States District Court for the Southern District of Texas, 4:11-cv-03198. Plaintiff alleged that the named defendants violated Sections 14(a) and 20(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and Rule 14a-9 promulgated thereunder by disseminating a false and materially misleading proxy statement in connection with the merger. Plaintiff sought an injunction prohibiting the proposed merger from going forward. The case was voluntarily dismissed on June 11, 2012.

On September 6, 2011, Donald A. Hysong, a purported unitholder of ENP, filed a putative class action complaint against ENP, ENP GP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard on behalf of the unitholders of ENP in the United States District Court for the District of Delaware that is captioned *Hysong v. Encore Energy Partners LP. et al*., 1:11-cv-00781-SD. Hysong alleged that the named defendants violated either Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder or Section 20(a) of the Exchange Act by disseminating a false and materially misleading proxy statement in connection with the merger. On September 14, 2011, in accordance with recent practice in Delaware, that case was assigned to Judge Stewart Dalzell of the Eastern District of Pennsylvania. On November 10, 2011, Judge Dalzell entered an order dismissing the lawsuit and entering judgment in the defendants' favor.

We cannot predict the outcome of the ENP Litigation or any other lawsuits, related to the ENP Litigation or other unrelated suits, that might be filed subsequent to the date of this filing, nor can we predict the amount of time and expense that will be required to resolve these lawsuits; therefore, we have not accrued a liability related to these lawsuits. We, ENP and the other defendants named in these lawsuits intend to defend vigorously against these and any other actions. While we cannot predict future outcomes of pending litigation, we do not believe that the ENP Litigation will result in a material adverse effect on our financial position, results of operations or cash flows. We also believe that our risk of material loss related to the ENP Litigation is remote.

9. Common Units and Net Income per Unit

Basic earnings per unit are computed in accordance with ASC Topic 260 "*Earnings Per Share*" ("ASC Topic 260") by dividing net income attributable to Vanguard unitholders by the weighted average number of units outstanding during the period. Diluted earnings per unit are 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. As of September 30, 2012, we had two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on the NYSE under the symbol VNR and (ii) Class B units, issued to management and an employee as discussed in Note 10. *Unit-Based Compensation*. The Class B units participate in distributions; therefore, all Class B units were considered in the computation of basic earnings per unit.

For the three months ended September 30, 2012, the 125,000 options previously granted to officers under the Vanguard Natural Resources, LLC Long-Term Incentive Plan ("VNR LTIP") have been excluded in the computation of earnings per unit as they had no dilutive effect. These options are included for the nine months ended September 30, 2012 as 53,189 additional common units would have been issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period. For the three and nine months ended September 30, 2011, these options were included in the computation of diluted earnings per unit as 57,269 and 62,894 additional common units, respectively, would have been issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period. The 522,500 phantom units granted to officers from 2010 to date under the VNR LTIP have been excluded in the computation of earnings per unit for the three and nine months ended September 30, 2012 as they had no dilutive effect. Of the 522,500 phantom units granted to date, 85,000 of them were granted to officers during 2010 and 2011 and have been included in the computation of earnings per unit for the three months ended September 30, 2011 as they had a dilutive effect and have been excluded for the nine months ended September 30, 2011 as they had no dilutive effect.

In accordance with ASC Topic 260, dual presentation of basic and diluted earnings per unit has been presented in the Consolidated Statements of Operations for the three and nine months ended September 30, 2012 and 2011 including each class of units issued and outstanding during the respective periods: common units and Class B units. Net income per unit is allocated to the common units and the Class B units on an equal basis.

Distributions Declared. The following table shows the amount per unit, record date and payment date of the cash distributions we paid on each of our common 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 August 2, 2012, our board of directors announced the change of our quarterly distribution policy to a monthly distribution policy. The monthly distribution policy commenced with the July 2012 distribution. On September 17, 2012, our board of directors declared a cash distribution attributable to the month of August 2012 of $0.20 per common unit.

	Cash Distributions		
Distribution	**Per Unit**	**Record Date**	**Payment Date**
2012			
August	$ 0.20	October 1, 2012	October 15, 2012
July	$ 0.20	September 4, 2012	September 14, 2012
Second Quarter	$ 0.60	August 7, 2012	August 14, 2012
First Quarter	$ 0.5925	May 8, 2012	May 15, 2012
2011			
Fourth Quarter	$ 0.5875	February 7, 2012	February 14, 2012
Third Quarter	$ 0.5775	November 7, 2011	November 14, 2011
Second Quarter	$ 0.575	August 5, 2011	August 12, 2011
First Quarter	$ 0.570	May 6, 2011	May 13, 2011
2010			
Fourth Quarter	$ 0.560	February 7, 2011	February 14, 2011

10. Unit-Based Compensation

In October 2007, two officers were granted options to purchase an aggregate of 175,000 units under the VNR LTIP with an exercise price equal to the initial public offering price of $19.00, which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant. These options were to expire on October 29, 2012. In September 2012, one of the officers exercised the option to purchase 50,000 of our common units at $19.00. The remaining options were exercised by both officers in October 2012. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718, "*Compensation-Stock Compensation,*" by calculating the Black-Scholes value of each option, using a volatility rate of 12.18%, an expected dividend yield of 8.95% and a discount rate of 5.12%, and multiplying the Black-Scholes value by the number of options awarded. In determining a volatility rate of 12.18%, we, due to a lack of historical data regarding our common units, used the historical volatility of the Citigroup MLP Index over the 365-day period prior to the date of grant.

In February 2010, we and VNRH entered into second amended and restated executive employment agreements (the "February Amended Agreements") with two executives. The February Amended Agreements were effective January 1, 2010 and will continue until January 1, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executives have given notice to the other parties that the February Amended Agreements should not be extended. Also, in June 2010, we and VNRH entered into a second amended and restated executive employment agreement (the "June Amended Agreement" and together with the February Amended Agreements, the "Amended Agreements") with one executive. The June Amended Agreement was effective May 15, 2010 and will continue until May 15, 2013, with subsequent one year renewals in the event that neither we, VNRH nor the executive have given notice to the other parties that the June Amended Agreement should not be extended. The Amended Agreements provide for an annual base salary and include an annual bonus structure for the executives. The annual bonus will be calculated based upon two company performance elements, absolute target distribution growth and relative unit performance to peer group, as well as a third discretionary element to be determined by our board of directors for the February Amended Agreements and by our Chief Executive Officer for the June Amended Agreement. Each of the three 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 times the respective executive's annual base salary. In addition, the Amended Agreements also provide for the executives to receive annual grants of restricted units and phantom units pursuant to the VNR LTIP.

During the nine months ended September 30, 2012, two of our executives were granted 15,000 phantom units each under the February Amended Agreements, and one executive was granted 12,500 phantom units under the June Amended Agreement. The phantom units are subject to a three-year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three-year anniversary of the date of grant so long as the executive remains continuously employed with us during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any distributions made by us on our units generally with respect to the number of phantom shares that the executive received pursuant to this grant. In the event the executive is terminated for "Cause" (as such term is defined in the Amended Agreements), all phantom units, whether vested or unvested, will be forfeited. The phantom units, once vested, shall be settled upon the earlier to occur of (a) the occurrence of a "Change of Control" (as defined in the VNR LTIP), or (b) the executive's separation from service. The amount to be paid in connection with these phantom units can be paid in cash or in units at the election of the officers and will be equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2013). Additionally, on August 1, 2012, three of our executives were granted a total of 390,000 phantom units. These phantom unit grants were made under the VNR LTIP and are subject to vesting in five equal annual installments, with the first vesting date being May 18, 2013, and each subsequent vesting date occurring on each annual anniversary of the first vesting date. As of September 30, 2012, an accrued liability of $1.5 million has been recorded and non-cash unit-based compensation expense of $0.6 million and $0.01 million for the three months ended September 30, 2012 and 2011, respectively, and $0.9 million and $0.3 million for the nine months ended September 30, 2012 and 2011, respectively, has been recognized in the selling, general and administrative expense line item in the Consolidated Statement of Operations.

During the first nine months of 2012, VNR employees were granted a total of 47,941 common units which will vest equally over a four year period. During the same period, the board members were granted a total of 14,112 common units which will vest one year from the date of grant. All of these grants have distribution equivalent rights that provide the grantee with a payment equal to the distribution on unvested units.

These common units, options and phantom units were granted as partial consideration for services to be performed and thus will be subject to accounting for these grants under ASC Topic 718. 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 September 30, 2012 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2011	366,670	$ 27.92
Granted	62,053	$ 27.89
Forfeited	(20,395)	$ 28.24
Vested	(109,465)	$ 27.94
Non-vested units at September 30, 2012	298,863	$ 27.89

At September 30, 2012, there was approximately $6.5 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 2.2 years. Our Consolidated Statements of Operations reflect non-cash compensation of $1.4 million and $0.8 million for the three months ended September 30, 2012 and 2011, respectively, and $3.3 million and $2.1 million for the nine months ended September 30, 2012 and 2011, respectively, in the selling, general and administrative expenses line item.

11. Shelf Registration Statements

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million (the “2009 Shelf Registration Statement”) of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. The 2009 Shelf Registration Statement expired in August 2012. Also, in July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million (the “2010 Shelf Registration Statement” and together with the 2009 Shelf Registration Statement, the “Shelf Registration Statements”) of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of each offering of securities issued under the Shelf Registration Statements are determined at the time of such offerings. The Shelf Registration Statements does not provide assurance that we will or could sell any such securities. Our ability to utilize the Shelf Registration Statements for the purpose of offering, from time to time, any combination of debt securities or common 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.

In August 2010, we entered into an Equity Distribution Program Distribution Agreement (the “2010 Distribution Agreement”) relating to our common units having an aggregate offering price of up to $60.0 million. Sales made pursuant to the 2010 Distribution Agreement were made through a prospectus supplement to our 2009 Shelf Registration Statement. Total net proceeds received under the 2010 Distribution Agreement through the expiration of the 2009 Shelf Registration Statement on August 2012 were approximately $6.3 million, after commissions, from the sales of 240,111 common units.

On September 9, 2011, we entered into an amended and restated Equity Distribution Program Distribution Agreement (the “2011 Distribution Agreement”) which extended, for an additional three years, the existing agreement with our sales agent to act as our exclusive distribution agent with respect to the issuance and sale of our common units up to an aggregate gross sales price of $200.0 million. Of the $200.0 million common units under the 2011 Distribution Agreement, $115.0 million of the common units were authorized to be offered through a prospectus supplement to our 2009 Shelf Registration Statement, which expired in August 2012. The additional $85.0 million of the common units may be offered pursuant to a new prospectus supplement to one of our existing effective shelf registration statements or a new shelf registration statement. Total net proceeds received under the 2011 Distribution Agreement through September 30, 2012, were approximately $5.5 million, after commissions, from the sales of 197,538 common units.

As a result of all our previous offerings, we have approximately $678.8 million remaining available as of September 30, 2012 under our 2010 Shelf Registration Statement.

In January 2012, we filed a registration statement (the “2012 Shelf Registration Statement”) with the SEC, which registered offerings of approximately 3.1 million common units held by certain selling unitholders. By means of the same registration statement, we also registered an indeterminate amount of common units, debt securities and guarantees of debt securities. Net proceeds, terms and pricing of each offering of securities issued under the 2012 Shelf Registration Statement are determined at the time of such offerings. The 2012 Shelf Registration Statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the 2012 Shelf Registration Statement for the purpose of offering, from time to time, any combination of debt securities or common 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 and the selling unitholder named therein.

In January 2012, we completed a public offering of 7,137,255 of our common units at a price of $27.71 per unit. The 7,137,255 common units offering included 4.0 million of our common units (“primary units”) and 3,137,255 common units (“secondary units”) offered by Denbury Onshore, LLC (“selling unitholder”). Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. T he secondary units were obtained by the selling unitholder as partial consideration for the ENP Purchase. We received proceeds of approximately $106.1 million from the offering of primary units, after deducting underwriting discounts of $4.3 million and offering costs of $0.4 million. We did not receive any proceeds from the sale of the secondary units. In addition, we received proceeds of approximately $28.5 million, after deducting underwriting discounts of $1.2 million, from the sale of an additional 1,070,588 of our common units that were offered to the underwriters to cover over-allotments pursuant to this offering. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility and our Second Lien Term Loan.

In September 2012, we completed a public offering of 6,000,000 of our common units at a price of $27.51 per unit. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $158.5 million from this offering, after deducting underwriting discounts of $6.4 million and offering costs of $0.1 million. In addition, we received proceeds of approximately $23.8 million, after deducting underwriting discounts of $1.0 million, from the sale of an additional 900,000 of our common units that were offered to the underwriters to cover over-allotments pursuant to this offering. We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Subsidiary Guarantors

We and VNRF, our 100% owned finance subsidiary, may co-issue securities pursuant to the registration statements 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, and any subsidiaries of Vanguard that do not guarantee the securities will be minor. There are no restrictions on our ability to obtain funds from our subsidiaries by dividend or loan.

12. Subsequent Events

Borrowing Base Redetermination

On October 5, 2012, our borrowing base under the Reserve-Based Credit Facility was increased to $1.0 billion from $975.0 million pursuant to our semi-annual redetermination but then reduced to $960.0 million as required for the additional senior notes offering discussed below.

Additional Senior Notes Offering

On October 9, 2012, we and our 100% owned finance subsidiary, VNRF, completed a public offering of an additional $200.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the “Additional Senior Notes”), pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received net proceeds of approximately $196.4 million from this offering, after deducting underwriting discounts of $3.5 million and offering costs of $0.1 million. As discussed in Note 3. *Debt*, we originally offered and sold $350.0 million aggregate principal amount of Senior Notes on April 4, 2012. The Additional Senior Notes have identical terms, other than the issue date, and constitute part of the same series as and are fungible with the Senior Notes. Further, like the Senior Notes, the Additional Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured basis, by our Subsidiary Guarantors, subject to the same guaranty release conditions.

We used the net proceeds from this offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

Distributions

On October 18, 2012, our board of directors declared a cash distribution attributable to the month of September 2012 of $0.20 per common unit ($2.40 on an annual basis) expected to be paid on November 14, 2012 to Vanguard unitholders of record as of the close of business on November 1, 2012.

Acquisitions

On November 1, 2012, we entered into a definitive agreement to acquire natural gas and NGL properties in the Piceance Basin in Colorado and the Powder River and Wind River Basins in Wyoming for a purchase price of $335.0 million from Bill Barrett Corporation. The effective date of the acquisition is October 1, 2012 and we anticipate closing this acquisition on or before December 31, 2012. 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 ("us," "we," "our," the "Company," "Vanguard" or "VNR"). The following discussion analyzes the financial condition and results of operations of Vanguard for the three and nine months ended September 30, 2012 and 2011. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Vanguard in conjunction with our Annual Report on Form 10-K for the fiscal year ended December 31, 2011 (the "2011 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 six operating areas:

- the Permian Basin in West Texas and New Mexico;
- the Big Horn Basin in Wyoming and Montana;
- the Arkoma Basin in Arkansas and Oklahoma;
- the Williston Basin in North Dakota and Montana;
- Mississippi; and
- South Texas.

As of September 30, 2012, based on internal reserve estimates, our total estimated proved reserves were 138.6 MMBOE, of which approximately 31% were oil reserves, 55% were natural gas reserves and 14% were NGLs reserves. Of these total estimated proved reserves, approximately 69%, or 95.5 MMBOE, were classified as proved developed. Also, at September 30, 2012, we owned working interests in 5,188 gross (1,780 net) productive wells. Our operated wells accounted for approximately 57% of our total estimated proved reserves at September 30, 2012. Our average net daily production for the year ended December 31, 2011 and for the nine months ended September 30, 2012 was 13,405 BOE/day and 16,786 BOE/day, respectively. Our average net production for the year ended December 31, 2011 includes production from the properties acquired in connection with the ENP Acquisition. Production from these properties during 2011 through the date of the completion of the ENP Merger on December 1, 2011 was subject to a 53.4% non-controlling interest in ENP. We own working interests ranging from 30% to 100% in approximately 57,378 gross undeveloped acres surrounding our existing wells. As of September 30, 2012, based on internal reserve estimates, approximately 31%, or 43.1 MMBOE, of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Recent Developments

Equity and Senior Notes Offering

On September 17, 2012, we completed a public offering of 6,000,000 of our common units at a price of $27.51 per unit. Offers were made pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received proceeds of approximately $158.5 million from this offering, after deducting underwriting discounts of $6.4 million and offering costs of $0.1 million. In addition, we received proceeds of approximately $23.8 million, after deducting underwriting discounts of $1.0 million, from the sale of an additional 900,000 of our common units that were offered to the underwriters to cover over-allotments pursuant to this offering.

As discussed in Note 12. *Subsequent Events*, we and our 100% owned finance subsidiary, VNRF, completed a public offering of an additional $200.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the "Additional Senior Notes") on October 9, 2012, pursuant to a prospectus supplement to the 2012 Shelf Registration Statement. We received net proceeds of approximately $196.4 million from this offering, after deducting underwriting discounts of $3.5 million and offering costs of $0.1 million. As discussed in Note 3. *Debt*, we originally offered and sold $350.0 million aggregate principal amount of initial notes on April 4, 2012 herein referred to as the "Senior Notes." The Additional Senior Notes have identical terms, other than the issue date, and constitute part of the same series as and are fungible with the Senior Notes. Further, like the Senior Notes, the Additional Senior Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured basis, by our Subsidiary Guarantors, subject to the same guaranty release conditions.

We used the net proceeds from both the equity and Additional Senior Notes offering to repay indebtedness outstanding under our Reserve-Based Credit Facility.

As discussed in Note 12. *Subsequent Events*, on November 1, 2012, we entered into a definitive agreement to acquire natural gas and NGL properties in the Piceance Basin in Colorado and the Powder River and Wind River Basins in Wyoming for a purchase price of $335.0 million from Bill Barrett Corporation. The effective date of the acquisition is October 1, 2012 and we anticipate closing this acquisition on or before December 31, 2012. 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 with oil price derivative contracts through 2015 and natural gas price derivative contracts through 2017. 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 and natural gas prices fluctuate, we will recognize non-cash, unrealized gains and losses in our Consolidated Statements of Operations related to the change in fair value of our commodity derivative contracts.

Production Decline

We also face the challenge of oil and natural gas 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 nine months ended September 30, 2012, we drilled eight gross (6.6 net) and completed five gross (4.1 net) operated wells. On our non-operated wells, we drilled five gross (0.9 net) and completed seven gross (0.9 net) wells. In addition, beginning in the third quarter of 2012, following the close date of the Arkoma Basin Acquisition, we have participated in drilling 31 gross (1.4 net) non-operated wells that were acquired in this acquisition. 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 and 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 accounting method and as such, each quarter we must perform a "ceiling test" that is impacted by declining prices. Additionally, we have recorded goodwill which represents the excess of the purchase price over the estimated fair value of the net assets acquired in the ENP Acquisition. Significant price declines could cause us to take one or more ceiling test write downs or cause us to record an impairment of goodwill, which would be reflected as non-cash charges against current earnings. An impairment of oil and natural gas properties in the amount of $18.0 million was recognized during the three months ended September 30, 2012 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, discounted at 10% and the lower of cost or fair value of unproved properties, excluding the value of our hedging contracts. At September 30, 2012, the 12-month average price was $2.77 per MMBtu for natural gas and $ 95.26 per barrel of crude oil.

Based on the 11-month average oil, natural gas and NGLs prices through November 1, 2012 and if such prices do not change for the remainder of 2012, we estimate that, on a pro forma basis, we will record an additional ceiling test write down on our existing assets of approximately $26.0 million at December 31, 2012. However, whether we will actually record an impairment during the quarter ended December 31, 2012 and whether the amount of any such impairment will be similar in amount to such estimate, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2012, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such an impairment. In the current natural gas price environment, where the historical 12-month average price is significantly 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, upon the acquisition of an oil and natural gas properties, the company records an asset based on the measurement of the fair value at the acquisition date of assets acquired. The fair value of assets acquired in an acquisition is determined using forward strip prices for oil and natural gas, 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. As a result, there is a risk that we will be required to record additional impairment of our oil and natural gas properties if certain attributes, such as declining oil and natural gas prices, continue. A significant impairment is anticipated in the quarter in which we close the recently announced acquisition of natural gas and NGL properties in the Piceance, Powder River and Wind River Basins, which is scheduled to close on or before December 31, 2012.

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012 (a)(b)	2011(a)(c)	2012 (a)(b)	2011(a)(c)
Revenues:				
Oil sales	$ 56,606	$ 54,493	$ 177,126	$ 172,815
Natural gas sales	15,193	13,805	29,931	37,020
NGLs sales	7,072	6,131	20,972	17,003
Oil, natural gas and NGLs sales	**78,871**	**74,429**	**228,029**	**226,838**
Loss on commodity cash flow hedges	—	(635)	—	(2,307)
Realized gain (loss) on commodity derivative contracts	318	1,902	(756)	4,474
Unrealized gain (loss) on commodity derivative contracts	(51,332)	109,639	9,243	68,625
Total revenues	**$ 27,857**	**$ 185,335**	**$ 236,516**	**$ 297,630**
Costs and expenses:				
Production:				
Lease operating expenses	$ 19,514	$ 14,230	$ 54,754	$ 41,683
Production taxes and marketing	7,053	7,693	21,164	21,319
Depreciation, depletion, amortization and accretion	31,245	21,419	73,897	62,797
Impairment of oil and natural gas properties	18,029	—	18,029	—
Selling, general and administrative expenses	5,499	6,493	15,298	18,713
Total costs and expenses	**$ 81,340**	**$ 49,835**	**$ 183,142**	**$ 144,512**
Other income (expense):				
Interest expense	$ (12,389)	$ (7,509)	$ (27,548)	$ (21,137)
Realized loss on interest rate derivative contracts	$ (468)	$ (664)	$ (1,610)	$ (2,169)
Unrealized loss on interest rate derivative contracts	$ (2,463)	$ (1,939)	$ (5,507)	$ (1,641)
Net gain (loss) on acquisition of oil and natural gas properties	$ —	$ 487	$ 13,796	$ (383)
Other	$ 76	$ 70	$ 191	$ 76

(a) During 2011 and 2012, we and ENP acquired certain oil and natural gas properties and related assets in the Permian Basin, Arkoma Basin, and the Wyoming, South Texas and Louisiana Gulf Coast areas. The operating results of these properties are included with ours from the closing date of the acquisition forward.

(b) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin in connection with the Unit Exchange. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(c) The operating results of the subsidiaries we acquired in the ENP Purchase through the date of the completion of the ENP Merger on December 1, 2011 were subject to a 53.4% non-controlling interest.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Revenues

Oil, natural gas and NGLs sales increased $4.4 million to $78.9 million during the three months ended September 30, 2012 as compared to the same period in 2011. The key oil, natural gas and NGLs revenue measurements were as follows:

	Three Months Ended September 30, 2012 (a)(b)	Three Months Ended September 30, 2011 (a)(c)	Percentage Increase / (Decrease)
Average realized prices, excluding hedges:			
Oil (Price/Bbl)	$ 82.98	$ 78.19	6%
Natural Gas (Price/Mcf)	$ 1.84	$ 5.34	(66)%
NGLs (Price/Bbl)	$ 37.91	$ 58.96	(36)%
Average realized prices, including hedges (d):			
Oil (Price/Bbl)	$ 83.14	$ 76.89	8%
Natural Gas (Price/Mcf)	$ 4.01	$ 8.00	(50)%
NGLs (Price/Bbl)	$ 37.91	$ 58.96	(36)%
Total production volumes:			
Oil (MBbls)	682	695	(2)%
Natural Gas (MMcf)	8,238	2,585	219%
NGLs (MBbls)	187	104	80%
Combined (MBOE)	2,242	1,230	82%
Average daily production volumes:			
Oil (Bbls/day)	7,415	7,556	(2)%
Natural Gas (Mcf/day)	89,547	28,099	219%
NGLs (Bbls/day)	2,028	1,131	79%
Combined (BOE/day)	24,367	13,371	82%

(a) During 2011 and 2012, we and ENP acquired certain oil and natural gas properties and related assets in the Permian Basin, Arkoma Basin, and the Wyoming, South Texas and Louisiana Gulf Coast areas. The operating results of these properties are included with ours from the closing date of the acquisition forward.

(b) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin in connection with the Unit Exchange. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(c) Production from the properties acquired related to the ENP Purchase during 2011 through the date of the completion of the ENP Merger on December 1, 2011 was subject to a 53.4% non-controlling interest in ENP.

(d) Excludes amortization of premiums paid and amortization on derivative contracts acquired.

The increase in oil, natural gas and NGLs sales during the three months ended September 30, 2012 compared to the same period in 2011 was due primarily to a significant increase in natural gas and NGL production. We experienced a 6% increase in the average realized oil price, excluding hedges, a 66% decrease in the average realized natural gas sales price received, excluding hedges and a 36% decrease in the average realized NGL price, excluding hedges. Oil revenues increased 4% from $54.5 million during the three months ended September 30, 2011 to $56.6 million during the three months ended September 30, 2012 as a result of a $4.79 per Bbl increase in our average realized oil price, excluding hedges. Our higher average realized oil price was primarily due to a higher average NYMEX price, which increased from $89.59 per Bbl in the third quarter of 2011 to $92.15 per Bbl in the third quarter of 2012. Natural gas revenues increased 10% from $13.8 million during the three months ended September 30, 2011 to $15.2 million during the same period in 2012 as a result of a 219% increase in our natural gas production volumes, even with a 66% decline in our average realized natural gas price, excluding hedges. Overall, our total production for the three months ended September 30, 2012 increased as compared to the same period in 2011, primarily as a result of the natural gas production associated with the Arkoma Basin Acquisition. On a BOE basis, crude oil, natural gas, and NGLs accounted for 30%, 61% and 9%, respectively, of our production during the three months ended September 30, 2012 compared to crude oil, natural gas and NGLs of 57%, 35% and 8%, respectively, during the same period in 2011.

Hedging and Price Risk Management Activities

During the three months ended September 30, 2012, we recognized a $0.3 million realized gain on commodity derivative contracts, of which, $18.0 million related to cash received in settlements which was offset by $3.5 million in amortization of premiums paid during the period and $14.2 million in amortization of the value on derivative contracts acquired. We also recognized a $51.3 million unrealized loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. These realized and unrealized gains resulted from the changes in commodity prices and the effect of these price changes is discussed in the paragraph below. During the three months ended September 30, 2011, we recognized $0.6 million in losses on commodity cash flow hedges that previously met the criteria for cash flow hedge accounting. This amount relates to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. They were later de-designated as cash flow hedges and the loss for the three months ended September 30, 2011 relates to amounts that settled in the respective periods which have been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is to 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 by us paying 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 current hedges are 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 our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our Consolidated Statements of Operations. However, these fair value changes that are reflected in the Consolidated Statements of Operations only 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 $5.3 million to $19.5 million for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011, of which $3.4 million related to increased lease operating expenses for oil and natural gas properties acquired during the fourth quarter of 2011 and the first nine months of 2012 and $3.8 million related to increased expenses on existing wells. Additionally, this increase was offset by approximately $2.1 million of lease operating expenses incurred in the third quarter of 2011 associated with the Appalachian Basin properties divested in March 2012 in connection with the Unit Exchange.

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 decreased by $0.6 million for the three months ended September 30, 2012 as compared to the same period in 2011. As a percentage of wellhead revenues, production, severance and ad valorem taxes decreased from 10.3% for the three months ended September 30, 2011 to 8.9% for the three months ended September 30, 2012.

Depreciation, depletion, amortization and accretion increased by approximately $9.8 million to $31.2 million for the three months ended September 30, 2012 from approximately $21.4 million for the three months ended September 30, 2011, primarily due to a higher depletion base associated with properties acquired in the Arkoma Basin Acquisition, offset by a lower depletion base associated with the Appalachian properties divested in connection with the Unit Exchange.

An impairment of oil and natural gas properties in the amount of $18.0 million was recognized during the three months ended September 30, 2012 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, discounted at 10% and the lower of cost or fair value of unproved properties. The impairment recorded during the third quarter 2012 was a result of a decline in natural gas prices at the measurement date, September 30, 2012. This impairment was calculated using the 12-month average price of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil. The most significant factor affecting this quarter's impairment related to the properties that we acquired in the Arkoma Basin Acquisition, when the forward natural gas price curve was higher than the 12-month average price. We were able to lock in the higher prices at the time of the acquisition for 100% of the estimated natural gas proved production through 2017 by using commodity derivative contracts. However, the impairment calculation did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended September 30, 2012 decreased $1.0 million as compared to the three months ended September 30, 2011. The three months ended September 30, 2011 included approximately $0.7 million in legal and advisory costs related to the ENP Merger completed in December 2011 and $0.4 million of integration costs associated with the ENP Acquisition. Additionally, contributing to the decrease in selling, general and administrative expenses, the three months ended September 30, 2012 included approximately $1.5 million of additional administrative overhead charged to interest owners in connection with the operating of new wells acquired. Furthermore, the decrease was offset by a $0.7 million increase in non-cash compensation expense related to additional restricted and phantom unit grants in the third quarter of 2012 and a $0.8 million increase in compensation related expenses due to additional employees.

Other Income and Expense

Interest expense increased to $12.4 million for the three months ended September 30, 2012 from $7.5 million for the three months ended September 30, 2011 primarily due to higher average outstanding debt under the Reserve-Based Credit Facility and additional debt outstanding along with a higher interest rate as a result of the Senior Notes offering completed in April 2012.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Revenues

Oil, natural gas and NGLs sales increased $1.2 million to $228.0 million during the nine months ended September 30, 2012 as compared to the same period in 2011. The key oil, natural gas and NGLs revenue measurements were as follows:

	Nine Months Ended September 30,		
	2012 (a)(b)	**2011 (a)(c)**	**Percentage Increase / (Decrease)**
Average realized prices, excluding hedging:			
Oil (Price/Bbl)	$ $85.93	$ $84.16	2%
Natural Gas (Price/Mcf)	$ $2.39	$ $4.75	(50)%
NGLs (Price/Bbl)	$ $46.21	$ $59.94	(23)%
Average realized prices, including hedging (d):			
Oil (Price/Bbl)	$ $84.16	$ $79.75	6%
Natural Gas (Price/Mcf)	$ $4.59	$ $7.43	(38)%
NGLs (Price/Bbl)	$ $46.21	$ $59.94	(23)%
Total production volumes:			
Oil (MBbls)	2,061	2,051	1%
Natural Gas (MMcf)	12,505	7,795	60%
NGLs (MBbls)	454	284	60%
Combined (MBOE)	4,599	3,634	27%
Average daily production volumes:			
Oil (Bbls/day)	7,523	7,513	—%
Natural Gas (Mcf/day)	45,639	28,552	60%
NGLs (Bbls/day)	1,656	1,040	60%
Combined (BOE/day)	16,786	13,312	26%

(a) During 2011 and 2012, we and ENP acquired certain oil and natural gas properties and related assets in the Permian Basin, Arkoma Basin, and the Wyoming, South Texas and Louisiana Gulf Coast areas. The operating results of these properties are included with ours from the closing date of the acquisition forward.

(b) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin in connection with the Unit Exchange. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(c) Production from the properties acquired related to the ENP Purchase during 2011 through the date of the completion of the ENP Merger on December 1, 2011 was subject to a 53.4% non-controlling interest in ENP.

(d) Excludes amortization of premiums paid and amortization on derivative contracts acquired.

Oil, natural gas and NGLs sales during the nine months ended September 30, 2012 remained relatively flat compared to the same period in 2011, due primarily to the increases in natural gas and NGL production, offset by lower pricing for natural gas and NGLs. We experienced a 60% increase in both our natural gas and NGL production during the nine months ended September 30, 2012. This increase is primarily due to the additional production from the Arkoma Basin Acquisition completed during the second quarter of 2012. Despite the production increase, natural gas revenues decreased 19% from $37.0 million during the nine months ended September 30, 2011 to $29.9 million during the same period in 2012 as a result of a 50% decline in the average realized natural gas sales price received, excluding hedges. Our lower average realized gas price was primarily due to a lower average NYMEX price, which decreased from $4.19 per Mcf in the first nine months of 2011 to $2.70 per Mcf in the first nine months of 2012. On a BOE basis, crude oil, natural gas and NGLs accounted for 45%, 45% and 10%, respectively, of our production during the nine months ended September 30, 2012 compared to crude oil, natural gas and NGLs of 56%, 36% and 8%, respectively, during the same period in 2011.

Hedging and Price Risk Management Activities

During the nine months ended September 30, 2012, we recognized a $0.8 million realized loss on commodity derivative contracts, of which, $23.8 million related to cash received in settlements which was offset by $10.5 million in amortization of premiums paid during the period and $14.1 million in amortization of the value on derivative contracts acquired. We also recognized a $9.2 million unrealized gain related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. These realized and unrealized gains and losses resulted from the changes in commodity prices, and the effect of these price changes is discussed in the paragraph below. During the nine months ended September 30, 2011, we recognized a $2.3 million loss on commodity cash flow hedges that previously met the criteria for cash flow hedge accounting. This amount relates to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. They were later de-designated as cash flow hedges and the loss for the nine months ended September 30, 2011 relates to amounts that settled in the respective periods which have been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is 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 by us paying 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 current hedges are 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 our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our Consolidated Statements of Operations. However, these fair value changes that are reflected in the Consolidated Statements of Operations only 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 increased by $13.1 million to $54.8 million for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011, of which $11.1 million related to increased lease operating expenses for oil and natural gas properties acquired during the fourth quarter of 2011 and first nine months of 2012, $3.3 million related to increased expenses on existing wells and $2.8 million related to higher than anticipated costs for work in progress at year end 2011, resulting in an increase of costs in the current year activity. Additionally, this increase was offset by approximately $4.2 million lease operating expenses associated with the Appalachian Basin properties divested in connection with the Unit Exchange.

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 taxes decreased by $0.2 million for the nine months ended September 30, 2012 as compared to the same period in 2011. As a percentage of wellhead revenues, production, severance, and ad valorem taxes decreased slightly from 9.4% for the nine months ended September 30, 2011 to 9.3% for the nine months ended September 30, 2012.

Depreciation, depletion, amortization and accretion increased to approximately $73.9 million for the nine months ended September 30, 2012 from approximately $62.8 million for the nine months ended September 30, 2011, primarily due to the increase in oil and natural gas properties related to the Arkoma Basin Acquisition and acquisitions completed during the fourth quarter of 2011.

An impairment of oil and natural gas properties in the amount of $18.0 million was recognized during the nine months ended September 30, 2012 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, discounted at 10% and the lower of cost or fair value of unproved properties. The impairment recorded during the third quarter 2012 was a result of a decline in natural gas prices at the measurement date, September 30, 2012. This impairment was calculated using the 12-month average price of $2.77 per MMBtu for natural gas and $95.26 per barrel of crude oil. The most significant factor affecting this quarter's impairment related to the properties that we acquired in the Arkoma Basin Acquisition, when the forward natural gas price curve was higher than the 12-month average price. We were able to lock in the higher prices at the time of the acquisition for 100% of the estimated natural gas proved production through 2017 by using commodity derivative contracts. However, the impairment calculation did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the nine months ended September 30, 2012 decreased $3.4 million as compared to the nine months ended September 30, 2011. Higher non-cash compensation expense related to additional unit grants in 2012 of approximately $1.1 million and higher compensation related expenses of $1.4 million during the first nine months of 2012, were offset by lower legal, advisory and integration costs related to the ENP Merger completed in December 2011. During the nine months ended September 30, 2011, we had approximately $1.2 million in legal and advisory costs related to the ENP Merger and $0.5 million of integration costs associated with the ENP Acquisition. Furthermore, contributing to the decrease in selling, general and administrative expenses, the nine months ended September 30, 2012 included approximately $4.2 million of additional administrative overhead charged to interest owners in connection with the operating of new wells acquired.

Other Income and Expense

Interest expense increased to $27.5 million for the nine months ended September 30, 2012 as compared to $21.1 million for the nine months ended September 30, 2011, primarily due to higher average outstanding debt under the Reserve-Based Credit Facility and additional debt outstanding along with a higher interest rate as a result of the Senior Notes offering completed in April 2012.

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 September 30, 2012, our critical accounting policies were consistent with those discussed in our 2011 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; however, 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 November 1, 2012, we had $556.5 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 $960.0 million and the next scheduled redetermination is in April 2013. 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 $159.2 million during the nine months ended September 30, 2012, as compared to $129.1 million during the nine months ended September 30, 2011. Changes in working capital increased total cash flows by $22.1 million in 2012 as compared to decreasing total cash flows by $10.0 million in 2011. Contributing to the increase in working capital during 2012 was a $31.9 million increase in accounts payable and oil and natural gas revenue payable, accrued expenses and other current liabilities that resulted primarily from the timing effects of payments, offset by an $8.2 million payment for price risk management activities. Unrealized derivative gains and losses are non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the nine months ended September 30, 2012 or 2011.

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, puts, swaptions, NYMEX collars and three-way collars to reduce our exposure to the volatility in oil and natural gas prices. See Note 4. *Price and Interest Rate Risk Management Activities* in Notes to Consolidated Financial Statements and Part I—Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk, for details about derivatives in place through 2016 for oil and natural gas.

Cash Flow from Investing Activities

Cash used in investing activities was approximately $492.0 million for the nine months ended September 30, 2012, as compared to $203.7 million during the same period in 2011. Cash used in investing activities during the first nine months of 2012 was primarily attributable to $40.3 million for the drilling and development of oil and natural gas properties, $452.1 million for the Wyoming II and Arkoma Basin Acquisitions and $4.8 million for deposits and prepayments related to the drilling and development of oil and natural gas properties, offset by $5.5 million in proceeds from the partial sale of certain oil and natural gas leases in the Williston region. Cash used in investing activities during the first nine months of 2011 was primarily attributable to $23.7 million for the drilling and development of oil and natural gas properties, $183.7 million for the acquisition of oil and natural gas properties, and $0.7 million for deposits and prepayments related to the acquisition and drilling and development of oil and natural gas properties, offset by $5.0 million in proceeds from the divestiture of certain oil and natural gas properties in the Permian Basin.

Cash Flow from Financing Activities

Cash provided by financing activities was approximately $354.4 million for the nine months ended September 30, 2012, as compared to $76.1 million for the nine months ended September 30, 2011. Cash provided by financing activities during the nine months ended September 30, 2012 included net proceeds from our public debt and equity offerings of $669.5 million and $549.0 million in proceeds from borrowings under our financing arrangements. Additionally, cash of $750.0 million was used in the repayments of our financing arrangements, $10.5 million was paid for financing costs and $104.5 million was paid to unitholders in the form of distributions. Cash provided by financing activities during the nine months ended September 30, 2011 included $164.0 million in net proceeds from borrowings under our financing arrangements, offset by $51.5 million in distributions to unitholders and $35.9 million in ENP's distributions to non-controlling interest.

Debt and Credit Facilities

Reserve-Based Credit Facility

On September 30, 2011, we entered into the Third Amended and Restated Credit Agreement (the "Credit Agreement") with a maximum facility amount of $1.5 billion (the "Reserve-Based Credit Facility") and an initial borrowing base of $765.0 million. This Credit Agreement provided for the (1) extension of the maturity date by five years maturing on October 31, 2016, (2) increase in the number of lenders from eight to twenty, (3) increase in the percentage of production that can be hedged into the future, (4) increase in the permitted debt to EBITDA coverage ratio from 3.5x to 4.0x, (5) elimination of the required interest coverage ratio, (6) elimination of the ten percent liquidity requirement to pay distributions to unitholders, and (7) ability to incur unsecured debt. Borrowings from the Reserve-Based Credit Facility and the Second Lien Term Loan (as discussed below) were used to fully repay outstanding borrowings from ENP's senior secured revolving credit facility and Vanguard's $175.0 million term loan. In November 2011, we entered into the First Amendment to the Third Amended and Restated Credit Agreement, which included amendments to (a) specify the effective date of November 30, 2011, (b) allow us to use the proceeds from our facility to refinance our debt under the Second Lien Term Loan, (c) include the current maturities under the Second Lien Term Loan in determining the consolidated current ratio, and (d) provide a cap on the amount of outstanding debt under the Second Lien Term Loan. On March 30, 2012, the closing date of the Unit Exchange, our borrowing base was reduced to $740.0 million and in April 2012, our borrowing base was further reduced to $670.0 million as a result of the completion of our Senior Notes offering. On June 29, 2012, in connection with the closing of the Arkoma Basin Acquisition, we entered into the Second Amendment to the Third Amended and Restated Credit Agreement (the "Second Amendment"). The Second Amendment increased the borrowing base to $975.0 million from $670.0 million and added two new lenders to the Reserve-Based Credit Facility.

At September 30, 2012, we had $570.0 million outstanding under our Reserve-Based Credit Facility and $405.0 million of borrowing capacity. 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.

On October 5, 2012, our borrowing base under the Reserve-Based Credit Facility was increased to $1.0 billion from $975.0 million pursuant to our semi-annual redetermination and was subsequently reduced to $960.0 million as a result of the completion of the Additional Senior Notes offering. As of November 1, 2012, we have $556.5 million available to be borrowed under our Reserve-Based Credit Facility.

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 September 30, 2012, 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, 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 September 30, 2012. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the reserve-based credit agreement 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 reserve-based 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 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.

Senior Notes

On April 4, 2012, we and our 100% owned finance subsidiary, VNRF, completed a public offering of $350.0 million aggregate principal amount of 7.875% senior unsecured notes due 2020 (the “Senior Notes”), at a public offering price of 99.274%, resulting in aggregate net proceeds of $339.6 million, after underwriting discounts and before expenses. Under the indenture governing the Senior Notes (the “Indenture”), all of our existing subsidiaries (other than VNRF) and certain of our future subsidiaries (the “Subsidiary Guarantors”) have unconditionally guaranteed, jointly and severally, on an unsecured basis, the Senior Notes, subject to release under certain of the following circumstances: (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 September 30, 2012, based on the most restrictive covenants of the Indenture, the Company’s cash balance and the borrowings available under the Reserve-Based Credit Facility, $280.0 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 103.93750% 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. We used a portion of the net proceeds from this offering to repay all indebtedness outstanding under our Second Lien Term Loan, and applied the balance of the net proceeds to outstanding borrowings under our Reserve-Based Credit Facility.

As discussed above, in October 2012, we completed a public offering of Additional Senior Notes. Please see Note 12. *Subsequent Events* of the Notes to the Consolidated Financial Statements and Part I—Item 2—Management’s Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments for further discussion.

Off-Balance Sheet Arrangements

At September 30, 2012, 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. There have been no material developments regarding the ENP Litigation as discussed in Part I—Item 3—Legal Proceedings in our 2011 Annual Report, other than as set forth in Part II—Item 1—Legal Proceedings in this Quarterly Report.

Commitments and Contractual Obligations

A summary of our contractual obligations as of September 30, 2012 is provided in the following table (in thousands):

	Payments Due by Year (in thousands)						
	2012	2013	2014	2015	2016	After 2016	Total
Management base salaries	$ 315	$ 131	$ —	$ —	$ —	$ —	$ 446
Asset retirement obligations (1)	482	2,291	797	658	2,854	38,550	45,632
Derivative liabilities (2)	2,920	26,020	14,098	9,858	3,664	—	56,560
Reserve-Based Credit Facility (3)	—	—	—	—	570,000	—	570,000
Senior Notes and related interest	6,891	27,563	27,563	27,563	27,563	441,875	559,018
Operating leases	162	204	215	195	—	—	776
Development commitments (4)	8,082	4,838	—	—	—	—	12,920
Total	$ 18,852	$ 61,047	$ 42,673	$ 38,274	$ 604,081	$ 480,425	$ 1,245,352

(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. *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.

Non-GAAP Financial Measure

Adjusted EBITDA

We present Adjusted EBITDA in addition to our reported net income (loss) attributable to Vanguard unitholders in accordance with GAAP. Adjusted EBITDA is a non-GAAP financial measure that is defined as net income (loss) attributable to Vanguard unitholders plus, for 2011, net income attributable to the non-controlling interest. The result is net income (loss) which includes the non-controlling interest for 2011. From this we add or subtract the following:

- Net interest expense, including write-off of deferred financing fees and realized gains and losses on interest rate derivative contracts;
- Depreciation, depletion, amortization and accretion;
- Impairment of oil and natural gas properties;
- Amortization of premiums paid on derivative contracts;
- Amortization of value on derivative contracts acquired;
- Unrealized gains and losses on commodity and interest rate derivative contracts;
- Net gains and losses on acquisition of oil and natural gas properties;
- Deferred taxes;
- Unit-based compensation expense;
- Unrealized fair value of phantom units granted to officers;
- Material transaction costs incurred on acquisitions and mergers;
- For 2011, non-controlling interest amounts attributable to each of the items above which revert the calculation back to an amount attributable to the Vanguard unitholders; and
- For 2011, administrative services fees charged to ENP, excluding the non-controlling interest, which are eliminated in consolidation.

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 the three months ended September 30, 2012 as compared to the three months ended September 30, 2011, Adjusted EBITDA attributable to Vanguard unitholders increased 79%, from $37.0 million to $66.3 million. For the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011, Adjusted EBITDA attributable to Vanguard unitholders increased 48%, from $111.1 million to $164.0 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Net income (loss) attributable to Vanguard unitholders	$ (68,727)	$ 75,884	$ 32,696	$ 77,271
Net income attributable to non-controlling interest	—	50,061	—	50,593
Net income (loss)	(68,727)	125,945	32,696	127,864
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	12,857	8,173	29,158	23,306
Depreciation, depletion, amortization and accretion	31,245	21,419	73,897	62,797
Impairment of oil and natural gas properties	18,029	—	18,029	—
Amortization of premiums paid on derivative contracts	3,441	4,663	10,516	9,501
Amortization of value on derivative contracts acquired	14,213	36	14,096	154
Unrealized (gains) losses on commodity and interest rate derivative contracts	53,795	(107,700)	(3,736)	(66,984)
Net (gain) loss on acquisition of oil and natural gas properties	—	(487)	(13,796)	383
Deferred taxes	(16)	220	(153)	415
Unit-based compensation expense	818	675	2,394	1,821
Fair value of phantom units granted to officers	622	77	864	310
Material transaction costs incurred on acquisitions and mergers	—	1,182	—	1,745
Adjusted EBITDA before non-controlling interest	66,277	54,203	163,965	161,312
Non-controlling interest attributable to adjustments above	—	(17,957)	—	(52,457)
Administrative services fees eliminated in consolidation	—	782	—	2,250
Adjusted EBITDA attributable to Vanguard unitholders	$ 66,277	$ 37,028	$ 163,965	$ 111,105

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 the Henry Hub, Houston Ship Channel, West Texas (“Waha Index”), El Paso Natural Gas Company (Permian Basin), Transwestern (Permian), Colorado Interstate Gas Company (Rocky Mountains) and Transcontinental Gas Pipe Line Corp: Zone 4 CenterPoint East prices for natural gas production while our realized pricing for oil production is primarily driven by the West Texas Intermediate (“WTI”) Light Sweet price and the Wyoming Imperial and Flint Hills Bow River prices. The NGLs price exposure is centered around the Oil Price Information Service postings as well as the market-negotiated ethane spot 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 or record an impairment of goodwill increases when oil and 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 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. These transactions may include price swaps whereby we will receive a fixed-price for our production and pay a variable market price to the contract counterparty. Additionally, we may acquire put options for which we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. As each monthly contract settles, we receive the excess, if any, of the fixed floor over the floating rate. We also enter into 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. Furthermore, we may enter into collars where we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor on a notional quantity. We also may enter into 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 of NYMEX WTI crude oil drops below the price of the short put. This allows us to settle for WTI 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. We also enter into swaption agreements, under which we provide options to counterparties to extend swap contracts into subsequent years. 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. Typically, management intends to hedge 75% to 85% of projected production up to a four-year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. We currently do not hedge our NGL production given the illiquid nature of NGL forward markets. 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 September 30, 2012, the fair value of commodity derivative contracts was an asset of approximately $79.8 million, of which $36.6 million settles during the next twelve months.

The following table summarizes natural gas commodity derivative contracts in place at September 30, 2012:

	October 1, - December 31, 2012	Year 2013	Year 2014	Year 2015	Year 2016	Year 2017
Gas Positions:						
Fixed Price Swaps:						
Notional Volume (MMBtu)	7,240,584	27,813,000	20,587,725	18,250,000	16,470,000	7,602,000
Fixed Price ($/MMBtu)	$ 5.15	$ 5.09	$ 5.07	$ 5.04	$ 5.04	$ 5.04
Puts:						
Notional Volume (MMBtu)	82,616	—	—	—	—	—
Fixed Price ($/MMBtu)	$ 6.76	$ —	$ —	$ —	$ —	$ —
Total Gas Positions:						
Notional Volume (MMBtu)	7,323,200	27,813,000	20,587,725	18,250,000	16,470,000	7,602,000
Floor Price ($/MMBtu)	$ 5.17	$ 5.09	$ 5.07	$ 5.04	$ 5.04	$ 5.04

The following table summarizes oil commodity derivative contracts in place at September 30, 2012:

	October 1, - December 31, 2012	Year 2013	Year 2014	Year 2015
Oil Positions:				
Fixed Price Swaps:				
Notional Volume (MBbls)	369	1,729	1,414	—
Fixed Price ($/Bbl)	$ 91.35	$ 90.59	$ 89.91	$ —
Collars:				
Notional Volume (MBbls)	104	82	12	—
Floor Price ($/Bbl)	$ 80.89	$ 88.89	$ 100.00	$ —
Ceiling Price ($/Bbl)	$ 99.47	$ 107.34	$ 116.20	$ —
Three-Way Collars:				
Notional Volume (MBbls)	216	876	566	194
Floor Price ($/Bbl)	$ 88.94	$ 95.21	$ 98.06	$ 100.00
Ceiling Price ($/Bbl)	$ 104.02	$ 107.94	$ 108.86	$ 124.53
Put Sold ($/Bbl)	$ 69.36	$ 72.76	$ 74.19	75.00
Put Spreads:				
Notional Volume (MBbls)	—	—	—	256
Floor Price ($/Bbl)	$ —	$ —	$ —	$ 100.00
Put Sold ($/Bbl)	$ —	$ —	$ —	$ 75.00
Total Oil Positions:				
Notional Volume (MBbls)	689	2,687	1,992	450
Floor Price ($/Bbl)	$ 89.02	$ 92.04	$ 92.29	$ 100.00

We sold oil puts for 2013 on 378,400 barrels at a weighted average price of $60.47. Additionally, we sold oil puts on 114,250 barrels at a weighted average price of $65.00 for the balance of 2012 through 2013.

As of September 30, 2012, the Company had the following open basis swap contracts:

	October 1, - December 31, 2012	Year 2013	Year 2014
Gas Positions:			
Notional Volume (MMBtu)	230,000	912,500	452,500
Weighted Avg. Basis Differential ($/MMBtu)(1)	$ (0.32)	$ (0.32)	$ (0.32)
Oil Positions:			
Notional Volume (MBbls)	21	84	—
Weighted Avg. Basis Differential ($/Bbl) (2)	$ 15.15	$ 9.60	$ —

(1) Natural gas basis swap contracts represent a weighted average differential between prices against Rocky Mountains (CIGC) and NYMEX Henry Hub prices.

(2) Oil basis swap contracts represent a weighted average differential between prices against Light Louisiana Sweet Crude (LLS) and NYMEX WTI prices.

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

	October 1, - December 31, 2012	Year 2013	Year 2014	Year 2015	Year 2016
Gas Positions:					
Notional Volume (MMBtu)	—	—	1,642,500	—	—
Weighted Average Fixed Price ($/MMBtu)	$ —	$ —	$ 5.69	$ —	$ —
Oil Positions:					
Notional Volume (MBbls)	35	196	493	508	622
Weighted Average Fixed Price ($/Bbl)	$ 100.00	$ 100.73	$ 117.22	$ 105.98	$ 125.00

Interest Rate Risks

At September 30, 2012, we had debt outstanding of $920.0 million. The amount outstanding under our Reserve-Based Credit Facility at September 30, 2012 was $570.0 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 $58.0 thousand 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 unrealized gains (losses) on interest rate derivative contracts.

The following summarizes information concerning our positions in open interest rate derivative contracts at September 30, 2012 (in thousands):

	October 1 - December 31, 2012	2013	2014	2015 (1)	2016 (2)
Weighted Average Notional Amount	$ 310,000	$ 310,000	$ 310,000	$ 297,836	$ 169,399
Weighted Average Fixed LIBOR Rate	1.47%	1.47%	1.47%	1.44%	1.49%

(1) On August 15, 2015, the counterparty has the option to extend the termination date of this contract for a notional amount of $30.0 million at 2.25% to August 5, 2018.

(2) On September 5, 2012, a counterparty exercised its option to put us into a $25,000 LIBOR swap at 1.25% for the period from September 7, 2012 to September 7, 2016.

Counterparty Risk

At September 30, 2012, 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 S&P 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 September 30, 2012
Citibank, N.A. (A)	$ 2,797	$ 4,452	$ (101)	$ (19)	$ 7,129
Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA-)	21,732	8,542	(7,584)	(9,589)	13,101
JP Morgan (A)	8,240	27,841	(3,263)	(1,564)	31,254
The Bank of Nova Scotia (AA-)	3,694	9,333	(2,466)	(10,290)	271
BBVA Compass (BBB)	—	450	—	(329)	121
Credit Agricole (A)	3,436	5,184	(2,194)	(2,380)	4,046
Royal Bank of Canada (AA-)	1,360	135	(1,726)	(1,077)	(1,308)
Natixis (A)	1,214	1,239	(112)	(1,017)	1,324
Bank of America (A)	—	—	(706)	(1,813)	(2,519)
Bank of Montreal (A+)	9,522	7,016	(1,484)	(3,149)	11,905
Canadian Imperial Bank of Commerce (A+)	2,950	3,962	(1,952)	(2,795)	2,165
Barclays (A+)	—	1,664	—	(950)	714
Total	$ 54,945	$ 69,818	$ (21,588)	$ (34,972)	$ 68,203

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.

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 September 30, 2012 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 third fiscal quarter of 2012 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.

There have been no material developments regarding the ENP Litigation as discussed in Part I—Item 3—Legal Proceedings in our 2011 Annual Report and Part II—Item 1—Legal Proceedings in our Quarterly Report on Form 10-Q for the period ended June 30, 2012, other than as set forth below.

On April 5, 2011, Stephen Bushansky, a purported unitholder of ENP, filed a putative class action complaint in the Delaware Court of Chancery on behalf of the unitholders of ENP. Another purported unitholder of ENP, William Allen, filed a similar action in the same court on April 14, 2011. The Bushansky and Allen actions have been consolidated under the caption *In re: Encore Energy Partners LP Unitholder Litigation*, C.A. No. 6347-VCP (the "Delaware State Court Action"). On December 28, 2011, those plaintiffs jointly filed their second amended consolidated class action complaint naming as defendants ENP, Scott W. Smith, Richard A. Robert, Douglas Pence, W. Timothy Hauss, John E. Jackson, David C. Baggett, Martin G. White, and Vanguard. That putative class action complaint alleges, among other things, that defendants breached the partnership agreement by recommending a transaction that is not fair and reasonable. Plaintiffs seek compensatory damages. Vanguard filed a motion to dismiss this lawsuit. On August 31, 2012, the Chancery Court entered an order granting Vanguard's motion to dismiss the complaint for failure to state a claim and dismissing the Delaware State Court Action with prejudice. On September 27, 2012, Plaintiffs in that matter filed a notice of their appeal of the dismissal.

We cannot predict the outcome of the ENP Litigation or any other lawsuits, related to the ENP Litigation or other unrelated suits, that might be filed subsequent to the date of this filing, nor can we predict the amount of time and expense that will be required to resolve these lawsuits; therefore, we have not accrued a liability related to these lawsuits. We, ENP and the other defendants named in these lawsuits intend to defend vigorously against these and any other actions. While we cannot predict future outcomes of pending litigation, we do not believe that the ENP Litigation will result in a material adverse effect on our financial position, results of operations or cash flows. We also believe that our risk of material loss related to the ENP Litigation is remote. 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 below or elsewhere 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 common units, please refer to Part I—Item 1A—Risk Factors in our 2011 Annual Report and to Part II—Item 1A—Risk Factors in our Quarterly Reports on Form 10-Q for the periods ended March 31, 2012 and June 30, 2012, as supplemented by the risk factor set forth below. There have been no material changes to the risk factors set forth in our 2011 Annual Report and Part II—Item 1A—Risk Factors in our Quarterly Reports on Form 10-Q for the periods ended March 31, 2012 and June 30, 2012, other than as set forth below.

Lower oil, natural gas and NGLs prices and other factors have resulted, and in the future may result, in ceiling test or goodwill write downs and other impairments of our asset carrying values.

We 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 net income in the period incurred and would reduce our members' equity.

The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil, natural gas and NGLs prices are low or volatile. In addition, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties and goodwill if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future operating or development costs increase. An impairment of oil and natural gas properties in the amount of $18.0 million was recognized during the three months ended September 30, 2012 as the unamortized cost of oil and natural gas properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of oil and natural gas, discounted at 10%, and the lower of cost or fair value of unproved properties, excluding the value of our hedging contracts. At September 30, 2012, the 12-month average price was $2.77 per MMBtu for natural gas and $ 95.26 per barrel of crude oil.

Based on the 11-month average oil, natural gas and NGLs prices through November 1, 2012 and if such prices do not change for the remainder of 2012, we estimate that, on a pro forma basis, we will record an additional ceiling test write down on our existing assets of approximately $26.0 million at December 31, 2012. However, whether we will actually record an impairment during the quarter ended December 31, 2012 and whether the amount of any such impairment will be similar in amount to such estimate, is contingent upon many factors such as the price of oil, natural gas and NGLs for the remainder of 2012, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and natural gas property acquisitions, which could increase, decrease or eliminate the need for such an impairment. In the current natural gas price environment, where the historical 12-month average price is significantly 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, upon the acquisition of an oil and natural gas properties, the company records an asset based on the measurement of the fair value at the acquisition date of assets acquired. The fair value of assets acquired in an acquisition is determined using forward strip prices for oil and natural gas, 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. As a result, there is a risk that we will be required to record additional impairment of our oil and natural gas properties if certain attributes, such as declining oil and natural gas prices, continue. A significant impairment is anticipated in the quarter in which we close the recently announced acquisition of natural gas and NGL properties in the Piceance, Powder River and Wind River Basins, which is scheduled to close on or before December 31, 2012.

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	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.1	First Amendment to the Vanguard Natural Resources, LLC Long-Term Incentive Plan	Filed herewith
10.2	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources, LLC, and Scott W. Smith	Form 8-K, filed August 6, 2012 (File No. 001-33756)
10.3	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources, LLC, and Richard Robert	Form 8-K, filed August 6, 2012 (File No. 001-33756)
10.4	Phantom Unit Award Agreement, dated August 1, 2012, by and between Vanguard Natural Resources, LLC, and Britt Pence	Form 8-K, filed August 6, 2012 (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: November 2, 2012

/s/ Richard A. Robert

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

Exhibit 10.1

FIRST AMENDMENT TO THE
VANGUARD NATURAL RESOURCES, LLC
LONG-TERM INCENTIVE PLAN

This First Amendment (the "***First Amendment***") to the Vanguard Natural Resources, LLC Long-Term Incentive Plan, as amended from time to time (the "***Plan***"), is made effective as of the effective date of the Plan (the "***Amendment Effective Date***"), by Vanguard Natural Resources, LLC, a Delaware limited liability company (the "***Company***").

W I T N E S S E T H:

WHEREAS, the Company previously established the Plan, under which the Company is authorized to grant equity-based incentive awards to certain employees and service providers of the Company and its affiliates;

WHEREAS, Section 7(a) of the Plan provides the Company's board of directors (the "***Board***") with the authority to amend the Plan in any manner; and

WHEREAS, the Board now desires to amend the Plan regarding the manner in which distribution equivalent rights ("***DERs***") may be granted under the Plan.

NOW, THEREFORE, the Plan shall be amended as of the Amendment Effective Date:

1. The definition of "Award" in Section 2 of the Plan is hereby deleted and replaced in its entirety with the following:

   "Award" means an Option, Unit Appreciation Right, Restricted Unit, Phantom Unit, Unit Award, or stand-alone DER granted under the Plan, and includes, as appropriate, any tandem DERs granted with respect to an Award (other than a Restricted Unit or a Unit Award).

2. The definition of "DER" in Section 2 of the Plan is hereby deleted and replaced in its entirety with the following:

   "DER" means a contingent right, granted alone or in tandem with a specific Award (other than a Restricted Unit or a Unit Award), to receive with respect to each Unit subject to the Award an amount in cash (or with respect to a DER granted in tandem with a Phantom Unit, an amount in cash, Units, and/or Phantom Units, as determined by the Committee in its sole discretion), equal in value to the distributions made by the Company with respect to a Unit during the period such Award is outstanding.

3. Section 6(b)(i) of the Plan shall be deleted, and subsections (ii), (iii), and (iv) of Section 6(b) of the Plan shall be renumbered as subsections (i), (ii), and (iii), respectively.

4. Section 6(d) of the Plan shall be re-designated as Section 6(e) of the Plan.

5. The following shall be added as a new Section 6(d) of the Plan:

   DERs. To the extent provided by the Committee, in its discretion, an Award (other than a Restricted Unit or Unit Award) may include a tandem DER grant (or a DER may be issued as a stand-alone Award), which may provide that such DERs shall be paid directly to the Participant, be credited to a bookkeeping account (with or without interest in the discretion of the Committee), be "reinvested" into additional Awards and be subject to the same or different vesting restrictions as the tandem Award, or be subject to such other provisions or restrictions as determined by the Committee in its discretion. Absent a contrary provision in the Award Agreement, upon a distribution with respect to a Unit, cash equal in value to such distribution shall be paid promptly to the Participant without vesting restrictions. Notwithstanding the foregoing, DERs shall only be paid in a manner that is either exempt from or in compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

6. Except as set forth above, the Plan shall continue to read in its current state.

IN WITNESS WHEREOF, the Company has caused the execution of this First Amendment by its duly authorized officer, effective as of the Amendment Effective Date.

VANGUARD NATURAL RESOURCES, LLC

By: /s/ Scott W. Smith
Scott W. Smith
President and Chief Executive 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: November 2, 2012

/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: November 2, 2012

/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 September 30, 2012 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)

November 2, 2012

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 September 30, 2012 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)

November 2, 2012