Vanguard Natural Resources, LLC
Form 10-Q
November 02, 2012

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2012

OR

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

For the transition period from to

Commission File Number: 001-33756

Vanguard Natural Resources, LLC
(Exact Name of Registrant as Specified in Its Charter)

Delaware	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. x Yes o No

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

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

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting
company)

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

Common units outstanding on 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, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 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:				
	—	50,061	—	50,593

Net income attributable to non-controlling interest								
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, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 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

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

	Nine Months Ended September 30, 2012	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

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

Description of the Business:

We are a publicly traded limited liability company focused on the acquisition and development of mature, long-lived oil and natural gas properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make monthly cash distributions to our unitholders and, over time, increase our monthly cash distributions through the acquisition of additional mature, long-lived oil and natural gas properties. Through our operating subsidiaries, 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
	$ 467	$ 381	$ 1,992	$ 381

Excess of revenues over direct operating expenses												
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	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

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Three-Way Collars

		Oil		
Contract Period	MBbls	Floor	Ceiling	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

	Gas	
Contract Period	MMBtu	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

		Oil	
Contract Period	MBbls	Floor	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
(2) notional amount of $30.0 million at 2.25% to August 5, 2018.
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
	Level 1	Level 2	Level 3	at Fair value
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
	Level 1	Level 2	Level 3	at Fair value
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.

Distribution	Per Unit	Cash Distributions 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. The 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		