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

Form 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2010
OR
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 001-33756

Vanguard Natural Resources, LLC

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (832) 327-2255

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

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

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

Large accelerated filer ☐ Accelerated filer ☒
Non-accelerated filer ☐ Smaller reporting company ☐
(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). Yes ☐ No ☒
Common units outstanding on August 2, 2010: 21,666,173.

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
Bcfe	= billion cubic feet of natural gas equivalents	MMBtu	= million British thermal units
Gal	= gallons	MMcf	= million cubic feet

When we refer to natural gas, natural gas liquids and oil in “equivalents,” we are doing so to compare quantities of natural gas liquids and oil with quantities of natural gas 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 natural gas liquids and one Bbl of oil or one Bbl of natural gas liquids 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 (1) “us,” “we,” “our,” “the Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC (“TEC”), VNR Holdings, Inc. (“VNRH”), Ariana Energy, LLC (“Ariana Energy”), Vanguard Permian, LLC (“Vanguard Permian”) and VNR Finance Corp. (“VNRF”) and (2) “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Revenues:				
Natural gas, natural gas liquids and oil sales	$ 19,446	$ 9,404	$ 39,516	$ 18,606
Loss on commodity cash flow hedges	(517)	(378)	(1,559)	(1,274)
Realized gain on other commodity derivative contracts	6,547	7,964	11,761	15,784
Unrealized gain (loss) on other commodity derivative contracts	(90)	(14,101)	10,720	(4,272)
Total revenues	25,386	2,889	60,438	28,844
Costs and expenses:				
Lease operating expenses	4,634	2,778	8,707	5,911
Depreciation, depletion, amortization, and accretion	5,713	2,645	9,951	6,428
Impairment of natural gas and oil properties	—	—	—	63,818
Selling, general and administrative expenses	1,134	2,941	2,534	6,093
Production and other taxes	1,880	921	3,462	1,563
Total costs and expenses	13,361	9,285	24,654	83,813
Income (loss) from operations	12,025	(6,396)	35,784	(54,969)
Other income and (expense):				
Interest expense	(1,523)	(979)	(2,814)	(1,992)
Realized loss on interest rate derivative contracts	(483)	(398)	(998)	(734)
Unrealized gain (loss) on interest rate derivative contracts	(434)	1,005	(684)	962
Loss on acquisition of natural gas and oil properties	(5,680)	—	(5,680)	—
Total other expense	(8,120)	(372)	(10,176)	(1,764)
Net income (loss)	$ 3,905	$ (6,768)	$ 25,608	$ (56,733)
Net income (loss) per Common and Class B units – basic and diluted	$ 0.19	$ (0.54)	$ 1.30	$ (4.51)
Weighted average units outstanding:				
Common units – basic	19,988	12,146	19,206	12,146
Common units – diluted	20,004	12,146	19,222	12,146
Class B units – basic & diluted	420	420	420	420

See accompanying notes to consolidated financial statements

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

	June 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 2,256	$ 487
Trade accounts receivable, net	8,586	8,025
Derivative assets	21,254	16,190
Other receivables	2,134	2,224
Other current assets	727	1,317
Total current assets	34,957	28,243
Natural gas and oil properties, at cost	514,354	399,212
Accumulated depletion	(236,477)	(226,687)
Natural gas and oil properties evaluated, net – full cost method	277,877	172,525
Other assets		
Derivative assets	9,546	5,225
Deferred financing costs	3,392	3,298
Other assets	2,172	1,409
Total assets	$ 327,944	$ 210,700
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 2,338	$ 766
Accounts payable – natural gas and oil	2,230	2,299
Payables to affiliates	935	1,387
Deferred swap premium liability	1,557	1,334
Derivative liabilities	353	253
Phantom unit compensation accrual	48	4,299
Accrued ad valorem taxes	1,162	903
Accrued expenses	835	1,178
Total current liabilities	9,458	12,419
Long-term debt	171,700	129,800
Derivative liabilities	2,553	2,036
Deferred swap premium liability	854	1,739
Asset retirement obligations	5,011	4,420
Total liabilities	189,576	150,414
Commitments and contingencies		
Members' equity		
Members' capital, 21,666,173 common units issued and outstanding at June 30, 2010 and 18,416,173 at December 31, 2009	136,813	59,873
Class B units, 420,000 issued and outstanding at June 30, 2010 and December 31, 2009	5,628	5,930
Accumulated other comprehensive loss	(4,073)	(5,517)
Total members' equity	138,368	60,286
Total liabilities and members' equity	$ 327,944	$ 210,700

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE SIX MONTHS ENDED JUNE 30, 2010 AND THE YEAR ENDED DECEMBER 31, 2009
(in thousands, except unit data)
(Unaudited)

	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Accumulated Other Comprehensive Loss	Total Members' Equity
Balance at January 1, 2009	12,146	$ 88,550	420	$ 4,606	$ (7,805)	$ 85,351
Distributions to members ($0.50 per unit to unitholders of record January 30, 2009, April 30, 2009, July 31, 2009 and November 6, 2009, respectively)	—	(26,258)	—	(840)	—	(27,098)
Issuance of common units, net of offering costs of $613	6,520	97,627	—	—	—	97,627
Redemption of common units	(250)	(4,305)	—	—	—	(4,305)
Unit-based compensation	—	(6)	—	2,164	—	2,158
Net loss	—	(95,735)	—	—	—	(95,735)
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	2,288	2,288
Balance at December 31, 2009	18,416	$ 59,873	420	$ 5,930	$ (5,517)	$ 60,286
Distributions to members ($0.525 per unit to unitholders of record February 5, 2010 and May 7, 2010)	—	(19,337)	—	(441)	—	(19,778)
Issuance of common units, net of offering costs of $191	3,250	71,374	—	—	—	71,374
Unit-based compensation	—	(705)	—	139	—	(566)
Net income	—	25,608	—	—	—	25,608
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	1,444	1,444
Balance at June 30, 2010	21,666	$ 136,813	420	$ 5,628	$ (4,073)	$ 138,368

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30,	
	2010	**2009**
Operating activities		
Net income (loss)	$ 25,608	$ (56,733)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	9,951	6,428
Impairment of natural gas and oil properties	—	63,818
Amortization of deferred financing costs	604	202
Unit-based compensation	466	1,763
Non-cash compensation associated with phantom units granted to officers	48	2,252
Amortization of premiums paid on derivative contracts	998	1,818
Amortization of value on derivative contracts acquired	1,168	754
Unrealized (gains) losses on other commodity and interest rate derivative contracts	(10,036)	3,310
Loss on acquisition of natural gas and oil properties	5,680	—
Changes in operating assets and liabilities:		
Trade accounts receivable	(561)	1,521
Other receivables	90	(398)
Payables to affiliates	(452)	(1,726)
Other current assets	77	267
Price risk management activities, net	(115)	(30)
Accounts payable	1,503	(1,934)
Accrued expenses	(3,525)	173
Other assets	(47)	(25)
Net cash provided by operating activities	31,457	21,460
Investing activities		
Additions to property and equipment	(121)	(9)
Additions to natural gas and oil properties	(7,647)	(1,912)
Acquisitions of natural gas and oil properties	(112,349)	(218)
Deposits and prepayments of natural gas and oil properties	(948)	(42)
Net cash used in investing activities	(121,065)	(2,181)
Financing activities		
Proceeds from borrowings	121,900	10,500
Repayment of debt	(80,000)	(13,000)
Proceeds from equity offering, net	71,374	—
Distributions to members	(19,778)	(12,566)
Financing costs	(698)	(177)
Purchase of units for issuance as unit-based compensation	(1,421)	(324)
Net cash provided by (used in) financing activities	91,377	(15,567)
Net increase in cash and cash equivalents	1,769	3,712
Cash and cash equivalents, beginning of period	487	3
Cash and cash equivalents, end of period	$ 2,256	$ 3,715
Supplemental cash flow information:		
Cash paid for interest	$ 2,148	$ 1,892
Non-cash financing and investing activities:		
Asset retirement obligations	$ 514	$ —
Non-monetary exchange of natural gas and oil properties	$ —	$ 2,660

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 June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 3,905	$ (6,768)	$ 25,608	$ (56,733)
Net gains (losses) from derivative contracts:				
Reclassification adjustments for settlements	448	357	1,444	1,244
Other comprehensive income	448	357	1,444	1,244
Comprehensive income (loss)	$ 4,353	$ (6,411)	$ 27,052	$ (55,489)

See accompanying notes to consolidated financial statements

Description of the Business:

We are a publicly-traded limited liability company focused on the acquisition and development of mature, long-lived natural gas and oil properties in the United States. Through our operating subsidiaries, we own properties in the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee, in the Permian Basin, primarily in west Texas and southeastern New Mexico, in south Texas and in Mississippi.

References in this report to (1) "us," "we," "our," "the Company," "Vanguard" or "VNR" are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC ("TEC"), VNR Holdings, Inc. ("VNRH"), Ariana Energy, LLC ("Ariana Energy"), Vanguard Permian, LLC ("Vanguard Permian") and VNR Finance Corp. ("VNRF") and (2) "Predecessor," "our operating subsidiary" or "VNG" are to Vanguard Natural Gas, LLC.

We were formed in October 2006 but effective January 5, 2007, Vanguard Natural Gas, LLC (formerly Nami Holding Company, LLC) was separated into our operating subsidiary and Vinland Energy Eastern, LLC ("Vinland"). As part of the separation, we retained all of our Predecessor's proved producing wells and associated reserves. We also retained 40% of our Predecessor's working interest in the known producing horizons in approximately 95,000 gross undeveloped acres and a contract right to receive approximately 99% of the net proceeds from the sale of production from certain producing gas and oil wells. In the separation, Vinland was conveyed the remaining 60% of our Predecessor's working interest in the known producing horizons in this acreage, 100% of our Predecessor's working interest in depths above and 100 feet below our known producing horizons. Vinland operates all of our existing wells in Appalachia and all of the wells that we drill in Appalachia.

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, 2009, from the audited financial statements filed in our 2009 Annual Report on Form 10-K. 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 2009 Annual Report on Form 10-K, 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 June 30, 2010, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2009 Annual Report on Form 10-K, except for those under *Recently Adopted Accounting Pronouncements*.

(a) ***Basis of Presentation and Principles of Consolidation:***

The consolidated financial statements as of June 30, 2010 and December 31, 2009 and for the three and six months ended June 30, 2010 and 2009 include our accounts and those of our wholly owned subsidiaries. We present our financial statements in accordance with GAAP. All intercompany transactions and balances have been eliminated upon consolidation.

(b) Recently Adopted Accounting Pronouncements:

In June 2009, the FASB issued guidance to change financial reporting by enterprises involved with variable interest entities ("VIEs"). The standard replaces the quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a VIE with an approach focused on identifying which enterprise has the power to direct the activities of a VIE and the obligation to absorb losses of the entity or the right to receive the entity's residual returns. This standard was effective for us on January 1, 2010. We do not have any interests in variable interest entities; therefore, this standard did not have any impact on our consolidated financial statements.

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance was effective for us on January 1, 2010 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard did not impact our results of operations, cash flows or financial position.

(c) New Pronouncements Issued But Not Yet Adopted:

In March 2010, the FASB issued authoritative guidance intended to clarify the scope exception related to embedded credit derivative features related to the transfer of credit risk in the form of subordination of one financial instrument to another. The guidance addresses how to determine which embedded credit derivative features, including those in collateralized debt obligations and synthetic collateralized debt obligations, are considered to be embedded derivatives that should not be analyzed under Accounting Standards Codification Topic 815, "Derivatives and Hedging" Subtopic 15-25 for potential bifurcation and separate accounting. This guidance is effective for each reporting entity at the beginning of its fiscal quarter beginning after June 15, 2010. We do not have any embedded credit derivative features with respect to our financial instruments; therefore, this standard is not expected to have any impact on our consolidated financial statements.

(d) *Use of Estimates:*

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

2. Acquisitions

On July 17, 2009, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd., a wholly-owned subsidiary of Lewis Energy Group, for the acquisition of certain natural gas and oil properties located in the Sun TSH Field in La Salle County, Texas. We refer to this acquisition as the "Sun TSH acquisition." The purchase price for said assets was $52.3 million with an effective date of July 1, 2009. We completed this acquisition on August 17, 2009 for an adjusted purchase price of $50.5 million. The adjusted purchase price was $50.5 million after consideration of preliminary purchase price adjustments of approximately $1.8 million, which included the settlement of a derivative contract for the latter part of August 2009 in the amount of $0.3 million. This acquisition was funded with borrowings under our reserve-based credit facility and proceeds from our public equity offering of 3.9 million common units completed on August 17, 2009. Upon closing this transaction, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August 2009 through December 2010, which had a fair value of $4.1 million on the closing date.

On November 27, 2009, we entered into a Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and a Conveyance Agreement to acquire certain producing natural gas and oil properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million, subject to customary post-closing adjustments. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.6 million common unit offering. In an effort to support stable cash flows from this transaction, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013.

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain natural gas and oil properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the "Parker Creek acquisition." The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010 for an adjusted purchase price of $114.6 million, after consideration of preliminary purchase price adjustments of approximately $1.5 million. The $114.6 million purchase price was funded from the approximate $71.5 million in net proceeds from our recent equity offering and with borrowings under the Company's existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel.

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Parker Creek acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a loss of $5.7 million, calculated in the following table. The loss resulted from a decrease in oil prices used to value the reserves and has been recognized in current period earnings and classified in other income and expense in the consolidated statement of operations.

	(in thousands)
Fair value of assets and liabilities acquired:	
Natural gas and oil properties	$ 107,920
Other assets	1,505
Asset retirement obligations	(500)
Total fair value of assets and liabilities acquired	108,925
Fair value of consideration transferred	114,605
Loss on acquisition of natural gas and oil properties	$ (5,680)

The following unaudited pro forma results for the three and six months ended June 30, 2010 and 2009 show the effect on our consolidated results of operations as if the Parker Creek acquisition had occurred on January 1, 2010 and January 1, 2009 and the Sun TSH and Ward County acquisitions had occurred on January 1, 2009. The pro forma results reflect the results of combining our statement of operations with the revenues and direct operating expenses of the oil and gas properties acquired adjusted for (1) assumption of asset retirement obligations and accretion expense for the properties acquired, (2) depletion expense applied to the adjusted basis of the properties acquired using the acquisition method of accounting, (3) interest expense on additional borrowings necessary to finance the acquisitions, (4) non-cash impairment charge, and (5) the impact of additional common units issued in connection with our 2010 equity offering completed at the time of the Parker Creek acquisition and our 2009 equity offerings completed at the time of the Sun TSH and Ward County acquisitions. The pro forma information is based upon these assumptions, and is not necessarily indicative of future results of operations (in thousands):

	Proforma (in thousands, except per unit data) (unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Total revenues	$ 27,639	$ 11,014	$ 66,916	$ 45,095
Net income (loss)	$ 5,454	$ (2,860)	$ 30,061	$ (48,917)
Net income (loss) per unit:				
Common & Class B units – basic	$ 0.25	$ (0.13)	$ 1.36	$ (2.21)
Common & Class B units – diluted	$ 0.25	$ (0.13)	$ 1.36	$ (2.21)

The amount of revenues and excess of revenues over direct operating expenses included in our 2010 consolidated statements of operations for each of our acquisitions mentioned above are shown in the table that follows. Direct operating expenses include lease operating expenses, selling general and administrative expenses and production and other taxes.

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
	(in thousands)	
Sun TSH		
Revenues	$ 2,772	$ 6,360
Excess of revenues over direct operating expenses	$ 1,324	$ 3,632
Ward County		
Revenues	$ 3,313	$ 7,236
Excess of revenues over direct operating expenses	$ 1,721	$ 4,707
Parker Creek		
Revenues	$ 2,038	$ 2,038
Excess of revenues over direct operating expenses	$ 1,709	$ 1,709

3. Credit Facility and Long-Term Debt

Our credit facility and long-term debt consisted of the following (in thousands):

Description	Interest Rate	Maturity Date	Amount Outstanding June 30, 2010	Amount Outstanding December 31, 2009
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 171,700	$ 129,800
			$ 171,700	$ 129,800

(1) Variable interest rate was 2.8% and 2.7% at June 30, 2010 and December 31, 2009, respectively.

Senior Secured Reserve-Based Credit Facility

In January 2007, we entered into a four-year revolving reserve-based credit facility ("reserve-based credit facility") with Citibank, N.A. and BNP Paribas. All of our Predecessor's outstanding debt was repaid with borrowings under this reserve-based credit facility, including an early prepayment penalty of $2.5 million. The available credit line ("borrowing base") is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value (as determined by the bank's petroleum engineers) of estimated future net cash flows from certain of our proved natural gas, natural gas liquids and oil reserves. The reserve-based credit facility is secured by a first lien security interest in all of our natural gas and oil properties. Additional borrowings were made in January 2008 pursuant to the acquisition of natural gas and oil properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. In July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the Dos Hermanos acquisition and in October 2008, we amended our reserve-based credit facility, which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, our reserve-based credit facility was amended to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. The other terms and conditions of the reserve-based credit facility remained substantially the same. Indebtedness under the reserve-based credit facility totaled $171.7 million at June 30, 2010.

Interest rates under the reserve-based credit facility are based on Eurodollar (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. At June 30, 2010 the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	***≤50%***	***>50% <75%***	***≥75% <90%***	***>90%***
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%
Commitment Fee Rate	0.50%	0.50%	0.50%	0.50%
Letter of Credit Fee	2.25%	2.50%	2.75%	3.00%

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, engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets, or make distributions to our unitholders when our outstanding borrowings exceed 90% of our borrowing base. At June 30, 2010, we were in compliance with our debt covenants.

4. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our reserve-based credit facility, Citibank N.A., BNP Paribas, The Bank of Nova Scotia, BBVA Compass Bank and Wells Fargo Bank, N.A. (also under the name Wachovia Bank, N.A.), to hedge price risk associated with a portion of our natural gas and oil production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. 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, such as the Columbia Gas Appalachian Index ("TECO Index"), Henry Hub or Houston Ship Channel for natural gas production and the West Texas Intermediate Light Sweet for oil production. In addition to these fixed price swap derivatives, we sell calls and give counterparties the option to extend certain swaps into subsequent years at specified pricing. Proceeds from the sale of the calls or extendable options may be used to improve the fixed price on the fixed price swaps. 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. 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 enter into fixed LIBOR interest rate swap agreements, 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," all derivative instruments are recorded on the 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. Gains and losses on derivative contracts that do not qualify for hedge accounting treatment are recorded as realized and unrealized gains (losses) on other commodity derivative contracts or realized and unrealized gains (losses) on interest rate derivative contracts in the consolidated statements of operations.

As of June 30, 2010, we have open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		**Oil**	
Contract Period	**MMBtu**	**Weighted Average Fixed Price**	**Bbls**	**WTI Price**
July 1, 2010 - December 31, 2010	2,241,930	$ 8.63	181,200	$ 87.16
January 1, 2011 - December 31, 2011	3,328,312	$ 7.83	443,250	$ 87.94
January 1, 2012 - December 31, 2012	—	$ —	347,700	$ 90.03
January 1, 2013 - December 31, 2013	—	$ —	296,400	$ 89.84
January 1, 2014 - December 31, 2014	—	$ —	209,875	$ 94.37

Swaptions

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

	Oil	
Contract Period	Bbls	Weighted Average Fixed Price
January 1, 2012 - December 31, 2012	45,750	$ 90.40
January 1, 2013 - December 31, 2013	32,100	$ 95.00
January 1, 2014 - December 31, 2014	127,750	$ 95.00
January 1, 2015 - December 31, 2015	292,000	$ 95.63

Collars

	Gas			Oil		
Production Period:	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
July 1, 2010 - December 31, 2010	901,600	$ 7.70	$ 8.93	—	$ —	$ —
January 1, 2011 - December 31, 2011	1,933,500	$ 7.34	$ 8.44	—	$ —	$ —
January 1, 2012 - December 31, 2012	—	$ —	$ —	45,750	$ 80.00	$ 100.25
January 1, 2013 - December 31, 2013	—	$ —	$ —	45,625	$ 80.00	$ 100.25

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 June 30, 2010, we have open interest rate derivative contracts as follows (in thousands):

Period:	Notional Amount	Fixed Libor Rates
July 1, 2010 to December 18, 2010	$ 10,000	1.50%
July 1, 2010 to December 20, 2010	$ 10,000	1.85%
July 1, 2010 to March 31, 2011	$ 20,000	2.08%
July 1, 2010 to December 10, 2012	$ 20,000	3.35%
July 1, 2010 to January 31, 2013	$ 20,000	2.38%
July 1, 2010 to January 31, 2013	$ 20,000	2.66%

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).

	June 30, 2010	December 31, 2009
Assets:		
Commodity derivatives	$ 39,950	$ 34,753
	$ 39,950	$ 34,753
Liabilities:		
Commodity derivatives	$ (9,150)	$ (13,405)
Interest rate swaps	(2,906)	(2,222)
	$ (12,056)	$ (15,627)

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. *Credit Facilities and Long-Term Debt* for further discussion) which is secured by our natural gas and oil 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 $40.0 million at June 30, 2010.

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 somewhat mitigated as of June 30, 2010.

Gain (Loss) on Derivatives

Gains and losses on derivatives are reported on the consolidated statement of operations in "gain (loss) on other commodity derivative contracts" and "loss on interest rate derivative contracts" and include realized and unrealized gains (losses). 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Realized gains (losses):				
Other commodity derivatives	$ 6,547	$ 7,964	$ 11,761	$ 15,784
Interest rate swaps	(483)	(398)	(998)	(734)
	$ 6,064	$ 7,566	$ 10,763	$ 15,050
Unrealized gains (losses):				
Other commodity derivatives	$ (90)	$ (14,101)	$ 10,720	$ (4,272)
Interest rate swaps	(434)	1,005	(684)	962
	$ (524)	$ (13,096)	$ 10,036	$ (3,310)
Total gains (losses):				
Other commodity derivatives	$ 6,457	$ (6,137)	$ 22,481	$ 11,512
Interest rate swaps	(917)	607	(1,682)	228
	$ 5,540	$ (5,530)	$ 20,799	$ 11,740

5. Fair Value Measurements

We adopted ASC Topic 820 for financial assets and financial liabilities as of January 1, 2008 and for non-financial assets and liabilities as of January 1, 2009. ASC Topic 820 does not expand the use of fair value measurements, but rather, 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 carried at fair value subsequent to an impairment write-down. It does not apply to oil and natural gas properties accounted for under the full cost method, which are subject to impairment based on Securities and Exchange Commission ("SEC") rules. ASC Topic 820 applies to assets and liabilities carried at fair value on the consolidated balance sheet, as well as to supplemental fair value information about financial instruments not carried at fair value.

The estimated fair values of our financial instruments closely approximate the carrying amounts as discussed below:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, payables to affiliates, phantom unit compensation accrual, accrued ad valorem taxes and accrued expenses. The carrying amounts approximate fair value due to the short maturity of these instruments.

Long-term debt. The carrying amount of our reserve-based credit facility approximates fair value because our current borrowing rate does not materially differ from market rates for similar bank borrowings.

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis. This includes natural gas, oil and interest rate derivatives contracts. 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. These assumptions include certain factors not consistently provided for previously by those companies utilizing fair value measurement; examples of such factors would include our own credit standing (when valuing liabilities) and the buyer's risk premium. In adopting ASC Topic 820, we determined that the impact of these additional assumptions on fair value measurements did not have a material effect on our financial position or results of operations.

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. Our commodity derivative instruments consist of swaps and options. 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 and ceilings 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 its derivative contracts as Level 2.

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

	June 30, 2010			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 30,800	$ —	$ 30,800
Total derivative instruments	$ —	$ 30,800	$ —	$ 30,800
Liabilities:				
Interest rate derivative contracts	—	(2,906)	—	(2,906)
Total derivative instruments	$ —	$ (2,906)	$ —	$ (2,906)

	December 31, 2009			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 21,415	$ —	$ 21,415
Total derivative instruments	$ —	$ 21,415	$ —	$ 21,415
Liabilities:				
Commodity price derivative contracts	$ —	$ (67)	$ —	$ (67)
Interest rate derivative contracts	—	(2,222)	—	(2,222)
Total derivative instruments	$ —	$ (2,289)	$ —	$ (2,289)

On January 1, 2009, we adopted the previously-deferred provisions of ASC Topic 820 for nonfinancial assets and liabilities, which are comprised primarily of asset retirement costs and obligations initially measured at fair value in accordance with ASC Topic 410 Subtopic 20 "Asset Retirement Obligations" ("ASC Topic 410-20"). 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. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 6, in accordance with ASC Topic 410-20. During the six months ended June 30, 2010, in connection with natural gas and oil properties acquired in the Parker Creek acquisition, we incurred and recorded asset retirement obligations totaling $0.5 million at fair value. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate (4.8%); and (4) the ten year average inflation factor (2.5%). The adoption of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, did not have a material impact on our financial position or results of operations.

6. Asset Retirement Obligations

The asset retirement obligations as of June 30 reported on our consolidated balance sheets and the changes in the asset retirement obligations for the six months ended June 30, were as follows (in thousands):

	2010	2009
Asset retirement obligations at January 1,	$ 4,420	$ 2,134
Liabilities added during the current period	514	—
Accretion expense	77	51
Asset retirement obligation at June 30,	$ 5,011	$ 2,185

7. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. We reimburse Vinland $60 per well per month (in addition to normal third party operating costs) for operating our current natural gas and oil properties in Appalachia under a Management Services Agreement (“MSA”) which costs are reflected in our lease operating expenses. Pursuant to an amendment to the MSA, we reimbursed Vinland $95 per well per month for the period from March 1, 2009 through December 31, 2009. Under a Gathering and Compression Agreement (“GCA”), Vinland receives a $0.25 per Mcf transportation fee on existing wells drilled at 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.” The GCA was amended for the period beginning March 1, 2009 through December 31, 2009, to provide for a temporary fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. The amendments to the MSA and the GCA expired on December 31, 2009 and all the terms of the agreements reverted back to the original agreements. Under the GCA, the transportation fee that we pay to Vinland only encompasses transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets would apply. These transportation fees are outlined in the GCA and are reflected in our lease operating expenses. Costs incurred under the MSA were $0.5 million for each of the three months ended June 30, 2010 and 2009 and $1.0 million and $0.7 million for the six months ended June 30, 2010 and 2009, respectively. Costs incurred under the GCA were $0.5 million and $0.3 million for the three months June 30, 2010 and 2009 and $0.8 million and $0.5 million for the six months ended June 30, 2010 and 2009, respectively. A payable of $0.9 million and $1.4 million, respectively, is reflected on our June 30, 2010 and December 31, 2009 consolidated balance sheets in connection with these agreements and direct expenses incurred by Vinland related to the drilling of new wells and operations of all of our existing wells in Appalachia.

On April 1, 2009, we and our wholly-owned subsidiary, TEC, exchanged several wells and lease interests (the “Asset Exchange”) with Vinland, Appalachian Royalty Trust, LLC, and Nami Resources Company, L.L.C. (collectively, the “Nami Companies”). Each of the Nami Companies is beneficially owned by Majeed S. Nami, who, as of June 30, 2010, beneficially owned 12.3% of our common units representing limited liability company interests. In the Asset Exchange, we assigned well, strata and leasehold interests with internal estimated future cash flows of approximately $2.7 million discounted at ten percent, and received well, strata, and leasehold interests with an approximately equal value; therefore no gain or loss was recognized.

8. Common Units and Net Income (Loss) per Unit

Basic earnings per unit is computed in accordance with ASC Topic 260 “Earnings Per Share” (“ASC Topic 260”), by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during the period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. As of June 30, 2010, we have 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 9. 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 and six months ended June 30, 2010, the 175,000 options granted to officers under the long-term incentive plan have been included in the computation of diluted earnings per unit as 15,909 additional common units would be issued and outstanding under the treasury stock method assuming the options had been exercised at the beginning of the period. For the three and six months ended June 30, 2009, these 175,000 options had no dilutive effect as the exercise price was higher than the market price at June 30, 2009; therefore, they have been excluded in the computation of diluted earnings per unit. In addition, the 42,500 phantom units granted to officers during 2010 under our long-term incentive plan had no dilutive effect on earnings per unit for the three and six months ended June 30, 2010; therefore, they have been excluded in the computation of diluted earnings per unit. The phantom units granted to officers in 2009 did not have a dilutive effect for the three and six months ended June 30, 2009; therefore, they have been excluded in the computation of earnings per unit.

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 six months ended June 30, 2010 and 2009 including each class of units issued and outstanding at that date: common units and Class B units. Net income (loss) per unit is allocated to the common units and the Class B units on an equal basis.

9. Unit-Based Compensation

In April 2007, the sole member at that time reserved 460,000 restricted Class B units in VNR for issuance to employees. Certain members of management were granted 365,000 restricted Class B units in VNR in April 2007, which vested two years from the date of grant. In addition, another 55,000 restricted VNR Class B units were issued in August 2007 to two other employees that were hired in April and May of 2007, which vested after three years. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future.

In October 2007 and February 2008, four board members were each granted 5,000 common units which vested after one year. Additionally, in October 2007, two officers were granted options to purchase an aggregate of 175,000 units under our long-term incentive plan 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. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718 “Compensation-Stock Compensation” (“ASC Topic 718”), 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%, the Company, due to a lack of historical data regarding the Company’s common units, used the historical volatility of the Citigroup MLP Index over the 365 day period prior to the date of grant.

On January 1, 2009, in accordance with their previously negotiated employment agreement, phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2009. The amount paid in connection with the 2009 phantom units, was paid in cash and in units at the election of the officers and was equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. As of June 30, 2009, an accrued liability and non-cash unit-based compensation expense of $2.3 million was recognized in the selling, general and administrative expense line item in the consolidated statement of operations.

Furthermore, on January 7, 2009, four board members were each granted 5,000 common units which vested in January 2010 and on February 27, 2009, employees were granted 17,950 units which vested in February 2010.

In January and March 2010, four board members were each granted 3,764 common units, one officer was granted 6,500 units and one board member was granted 2,663 common units each of which will vest after one year. In February 2010, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the “Amended Agreements”) with two executives. The 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 agreements should not be extended. Also in June 2010, the Company and VNRH entered into a second amended and restated Executive Employment Agreement (the “Amended Agreement”) with one executive. The 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 agreements should not be extended. All three 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 Amended Agreements entered into in February 2010 and by the Chief Executive officer for the Amended Agreement entered into in June 2010. 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.

The Amended Agreements entered into in February 2010 also provide for each executive to receive 15,000 restricted units granted pursuant to the Vanguard Natural Resources, LLC Long-Term Incentive Plan (the “LTIP”) and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 restricted units granted pursuant to the LTIP. The restricted units are subject to a vesting period of three years. One-third of the aggregate number of the restricted units will vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. In the event the executives are terminated without “Cause,” or the executive resigns for “Good Reason” (each term of which is defined in the executive’s respective Amended Agreement), or the executive is terminated due to his death or “Disability” (as such term is defined in the Amended Agreement), all unvested outstanding restricted units shall receive accelerated vesting. Where the executive is terminated for “Cause,” all restricted units, whether vested or unvested, will be forfeited. Upon the occurrence of a “Change of Control,” (as defined in the LTIP), all unvested outstanding restricted units shall vest.

In addition, the Amended Agreements entered into in February 2010 provide for each executive to receive an annual grant of 15,000 phantom units granted pursuant to the LTIP and the Amended Agreement entered into in June 2010 provides for the executive to receive an annual grant of 12,500 phantom units granted pursuant to the LTIP. The phantom units are also 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 the Company 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 the Company on its units generally with respect to the number of phantom shares that executive received pursuant to this grant. In the event the executive is terminated for “Cause” (as such term is defined in the Amended Agreement), 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 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). As of June 30, 2010, an accrued liability and non-cash unit-based compensation expense of $0.05 million has been recognized in the selling, general and administrative expense line item in the consolidated statement of operations.

These common units, Class B units, options and phantom units were granted as partial consideration for services to be performed under employment contracts 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 June 30, 2010 is presented below:

	Number of Non-vested Units	**Weighted Average Grant Date Fair Value**
Non-vested units at December 31, 2009	92,950	$ 14.54
Granted	66,719	$ 22.18
Vested	(92,950)	$ (14.54)
Non-vested units at June 30, 2010	66,719	$ 22.18

At June 30, 2010, there was approximately $1.2 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.9 years. Our consolidated statements of operations reflects non-cash compensation of $0.2 million and $1.8 million in the selling, general and administrative line item for the three months ended June 30, 2010 and 2009 and $0.5 million and $4.0 million for the six months ended June 30, 2010 and 2009, respectively.

10. Shelf Registration Statement

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities 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 July 2010, a new shelf registration statement was filed with the SEC. See Note 11. *Subsequent Event* for additional information.

In August 2009, we completed an offering of 3.9 million of our common units. The units were offered to the public at a price of $14.25 per unit. We received net proceeds of approximately $53.2 million from the offering, after deducting underwriting discounts of $2.4 million and offering costs of $0.5 million. In December 2009, we completed an offering of 2.6 million of our common units. The units were offered to the public at a price of $18.00 per unit. We received net proceeds of approximately $44.4 million from the offering, after deducting underwriting discounts of $2.0 million and offering costs of $0.1 million. We paid $4.3 million of the proceeds from this offering to redeem 250,000 common units from our largest unitholder. In May 2010, we completed an offering of 3.3 million of our common units. The units were offered to the public at a price of $23.00 per unit. We received proceeds of approximately $71.5 million from the offering, after deducting underwriting discounts of $3.2 million and offering costs of $0.06 million.

As a result of these offerings, we have approximately $122.6 million remaining available under our 2009 shelf registration statement as of June 30, 2010.

11. Subsequent Event

In July 2010, we filed a registration statement with the SEC which registered offerings of up to $800.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries, and which, as of the date of the issuance of these financial statements, has yet to be declared effective. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities 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.

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

The following discussion and analysis should be read in conjunction with the financial statements and related notes presented in Item 1 of this Quarterly Report on Form 10-Q and information disclosed in our 2009 Annual Report on Form 10-K.

Forward-Looking Statements

This report contains "forward-looking statements" intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995. Statements included in this quarterly report 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.

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 Factor section of the 2009 Annual Report on Form 10-K and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the SEC, which are available on our website at www.vnrllc.com and through the SEC's Electronic Data Gathering and Retrieval System ("EDGAR") at http://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.

Overview

We are a publicly-traded limited liability company focused on the acquisition and development of mature, long-lived natural gas and oil properties in the United States. Our primary business objective is to generate stable cash flows allowing us to make quarterly cash distributions to our unitholders and over time to increase our quarterly cash distributions through the acquisition of new natural gas and oil properties. Our properties are located in the southern portion of the Appalachian Basin, primarily in southeast Kentucky and northeast Tennessee, the Permian Basin, primarily in west Texas and southeastern New Mexico, in south Texas and in Mississippi.

We owned working interests in 2,109 gross (1,210 net) productive wells at June 30, 2010, and our average net production for the year ended December 31, 2009 and for the six months ended June 30, 2010 was 20,010 Mcfe per day and 26,774 Mcfe per day, respectively. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. We have an approximate 40% working interest in the known producing horizons in approximately 109,500 gross undeveloped acres surrounding or adjacent to our existing wells located in southeast Kentucky and northeast Tennessee. Furthermore, in South Texas, the Permian Basin and Mississippi, we own working interest ranging from 30-100% in approximately 16,930 undeveloped acres surrounding our existing wells. Based on internal reserve estimates at June 30, 2010, approximately 32% or 56.2 Bcfe of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Disruption to Functioning of Capital Markets

Multiple events during 2009 involving numerous financial institutions have effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

During the first half of 2010, our unit price closed at a high of $25.19 on March 2, 2010 and our unit price declined to a closing low of $18.93 on May 20, 2010. Also, during the six months ended June 30, 2010, we completed one well on an operated property, drilled one operated well to be completed in the third quarter and drilled and completed four non-operated wells. We intend to move forward with our development drilling program in the second half of 2010 on selected wells that we expect will allow for an adequate return on the drilling investment. Future drilling will be done only when adequate returns and liquidity will allow. Maintaining adequate liquidity may involve the issuance of debt or equity at less attractive terms, could involve the sale of non-core assets, and could require reductions in our capital spending. In the near-term, we will focus on maximizing returns on existing assets by managing our costs, selectively deploying capital to improve existing production and drilling a limited number of wells which we believe will provide an adequate return on the investment.

Sun TSH Acquisition

On July 17, 2009, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling Ltd. ("Segundo"), a wholly-owned subsidiary of Lewis Energy Group ("Lewis"), to acquire certain natural gas and oil properties located in the Sun TSH Field in La Salle County, Texas for $52.3 million, referred to as the "Sun TSH acquisition." The acquisition had a July 1, 2009 effective date and was completed on August 17, 2009 for an adjusted purchase price of $50.5 million. An affiliate of Lewis operates all of the wells acquired in this transaction. This acquisition was funded with borrowings under our reserve-based credit facility and proceeds from our public equity offering of 3.9 million common units completed on August 17, 2009. At closing, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010, which had a fair value of $4.1 million on the closing date. In addition, concurrent with the execution of the Purchase and Sale Agreement, we entered into a collar for certain volumes in 2010 and a series of collars for a substantial portion of the expected gas production for 2011 at prices above the then current market with a total cost to us of $3.1 million which was financed through deferred premiums. Inclusive of the hedges added, approximately 90% of the estimated gas production from existing producing wells in the acquired properties is hedged through 2011. As of June 30, 2010, based on internal reserve estimates, these acquired properties have estimated proved reserves of 35.0 Bcfe, 98% of which is natural gas and natural gas liquids and 61% is proved developed producing.

Ward County Acquisition

On November 27, 2009, we entered into a Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and a Conveyance Agreement to acquire certain producing natural gas and oil properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million, subject to customary post-closing adjustments. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.3 million common unit offering. We operate all but one of the ten wells acquired in this transaction. As of June 30, 2010, based on internal reserve estimates, these acquired properties have estimated proved reserves of 3.6 million barrels of oil equivalent, 81% of which is oil and 61% is proved developed. In an effort to support stable cash flows from this transaction, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013.

Parker Creek Acquisition

On April 30, 2010, we entered into a definitive agreement with a private seller for the acquisition of certain natural gas and oil properties located in Mississippi, Texas and New Mexico. We refer to this acquisition as the "Parker Creek acquisition." The purchase price for said assets was $113.1 million with an effective date of May 1, 2010. We completed this acquisition on May 20, 2010 for an adjusted purchase price of $114.6 million, after consideration of preliminary purchase price adjustments of approximately $1.5 million. The $114.6 million purchase price was funded from the approximate $71.5 million in net proceeds from our recent equity offering and with borrowings under the Company's existing reserve-based credit facility. In conjunction with the acquisition, we entered into crude oil hedges covering approximately 56% of the estimated production from proved producing reserves through 2013 at a weighted average price of $91.70 per barrel. As of June 30, 2010, based on internal reserve estimates, these acquired properties have estimated proved reserves of 4.7 million barrels of oil equivalent, 96% of which is oil and 61% is proved developed.

Our Relationship with Vinland

On April 18, 2007 but effective as of January 5, 2007, we entered into various agreements with Vinland, under which we rely on Vinland to operate our existing producing wells in Appalachia and coordinate our development drilling program in Appalachia. We expect to benefit from the substantial development and operational expertise of Vinland management in the Appalachian Basin. Under a management services agreement, Vinland advises and consults with us regarding all aspects of our production and development operations in Appalachia and provides us with administrative support services as necessary for the operation of our business. In addition, Vinland may, but does not have any obligation to, provide us with acquisition services under the management services agreement. Under a gathering and compression agreement that we entered into with Vinland Energy Gathering, LLC ("VEG"), VEG gathers, compresses, delivers, and provides the services necessary for us to market our natural gas production in the area of mutual interest, or "AMI." VEG delivers our natural gas production to certain designated interconnects with third-party transporters.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility which is available for our general limited liability company purposes, including, without limitation, capital expenditures and acquisitions. Our obligations under the reserve-based credit facility are secured by substantially all of our assets. Our initial borrowing base under the reserve-based credit facility was set at $115.5 million. However, the borrowing base was subject to $1.0 million reductions per month starting on July 1, 2007 through November 1, 2007, which resulted in a borrowing base of $110.5 million as reaffirmed in November 2007 pursuant to a semi-annual borrowing base redetermination. We applied $80.0 million of our net proceeds from our IPO in October 2007 to reduce our indebtedness under our reserve-based credit facility. Additional borrowings under our reserve-based credit facility were made in January 2008 in connection with the acquisition of natural gas and oil properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserve-based credit facility was amended in anticipation of a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. In July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the Dos Hermanos acquisition. In October 2008, we amended our reserve-based credit facility which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, a third amendment was entered into which amended covenants to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by us due the Ward County acquisition. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. The other terms and conditions of the reserve-based credit facility remained substantially the same. Indebtedness under the reserve-based credit facility totaled $171.7 million at June 30, 2010, and the applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	***≤50%***	***>50% <75%***	***≥75% <90%***	***>90%***
Eurodollar Loans Margin	2.25%	2.50%	2.75%	3.00%
ABR Loans Margin	1.25%	1.50%	1.75%	2.00%
Commitment Fee Rate	0.50%	0.50%	0.50%	0.50%
Letter of Credit Fee	2.25%	2.50%	2.75%	3.00%

Outlook

Our revenue, cash flow from operations, and future growth depend substantially on factors beyond our control, such as access to capital, economic, political and regulatory developments, and competition from other sources of energy. Multiple events during 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe, and other nations around the world to provide liquidity to the financial sector appears to have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

Natural gas, natural gas liquids and oil prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for natural gas or oil could materially and adversely affect our financial position, our results of operations, the quantities of natural gas and oil reserves that we can economically produce, our access to capital and our ability to pay a distribution. We have mitigated the volatility on our cash flows with natural gas price derivative contracts through 2011 and oil price derivative contracts through 2014. These hedges are placed on a portion of our proved producing and a portion of our total anticipated production during this time frame. As natural gas, natural gas liquids and oil prices fluctuate, we will recognize non-cash, unrealized gains and losses in our consolidated statement of operations related to the change in fair value of our commodity derivative contracts.

We face the challenge of natural gas and oil production declines. As a given well's initial reservoir pressures are depleted, natural gas, natural gas liquids and oil production decreases, thus reducing our total reserves. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will maintain our focus on controlling costs to add reserves through drilling and acquisitions, as well as controlling the corresponding costs necessary to produce such reserves. During the six months ended June 30, 2010, we completed one well on an operated property, drilled one operated well to be completed in the third quarter and drilled and completed four non-operated wells. In addition, we anticipate that during the second half of 2010 we will start one horizontal oil well in the Permian operating area, complete six vertical oil wells in Appalachia, three vertical gas wells in South Texas and one vertical oil well in Mississippi at a total cost of approximately $6.9 million. Our ability to add reserves 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 production 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 reserve-based credit facility when it expires. Additionally, due to the significant decline in commodity prices, our borrowing base under our reserve-based credit facility may be redetermined such that it will not provide for the working capital necessary to fund our capital spending program and could affect our ability to make distributions.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010(c)	**2009(a)(b)**	**2010(c)**	**2009(a)(b)**
Revenues:				
Natural gas sales	$ 6,386	$ 4,760	$ 13,904	$ 10,758
Natural gas liquids sales	2,038	351	4,924	675
Oil sales	11,022	4,293	20,688	7,173
Natural gas, natural gas liquids and oil sales	**19,446**	**9,404**	**39,516**	**18,606**
Loss on commodity cash flow hedges	(517)	(378)	(1,559)	(1,274)
Realized gain on other commodity derivative contracts	6,547	7,964	11,761	15,784
Unrealized gain (loss) on other commodity derivative contracts	(90)	(14,101)	10,720	(4,272)
Total revenues	**$ 25,386**	**$ 2,889**	**$ 60,438**	**$ 28,844**
Costs and expenses:				
Lease operating expenses	$ 4,634	$ 2,778	$ 8,707	$ 5,911
Depreciation, depletion, amortization, and accretion	5,713	2,645	9,951	6,428
Impairment of natural gas and oil properties	—	—	—	63,818
Selling, general and administrative expenses	1,134	2,941	2,534	6,093
Production and other taxes	1,880	921	3,462	1,563
Total costs and expenses	**$ 13,361**	**$ 9,285**	**$ 24,654**	**$ 83,813**
Other income and (expense):				
Interest expense, net	$ (1,523)	$ (979)	$ (2,814)	$ (1,992)
Realized loss on interest rate derivative contracts	$ (483)	$ (398)	$ (998)	$ (734)
Unrealized gain (loss) on interest rate derivative contracts	$ (434)	$ 1,005	$ (684)	$ 962
Loss on acquisition of natural gas and oil properties	$ (5,680)	$ —	$ (5,680)	$ —

(a) The Sun TSH acquisition closed on August 17, 2009 and, as such, no operations are included in the three month or six month period ended June 30, 2009.

(b) The Ward County acquisition closed on December 2, 2009 and, as such, no operations are included in the three month or six month period ended June 30, 2009.

(c) The Parker Creek acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the three month and six month period ended June 30, 2010, and no operations are included in the three or six month period ended June 30, 2009.

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009

Revenues

Natural gas, natural gas liquids and oil sales increased $10.0 million to $19.4 million during the three months ended June 30, 2010 as compared to the same period in 2009. The key revenue measurements were as follows:

	Three Months Ended June 30,		Percentage Increase (Decrease)
	2010	2009	
Net Natural Gas Production:			
Appalachian gas (MMcf)	747	794	(6)%
Permian gas (MMcf)	82	53(b)	56%
South Texas gas (MMcf)	437(a)	200(a)(c)	118%
Total natural gas production (MMcf)	1,266	1,047	21%
Average Appalachian daily gas production (Mcf/day)	8,210	8,726	(6)%
Average Permian daily gas production (Mcf/day)	903	578(b)	56%
Average South Texas daily gas production (Mcf/day)	4,799(a)	2,199(a)(c)	118%
Average Vanguard daily gas production (Mcf/day)	13,912	11,503	21%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$ 10.09(d)	$ 11.28(d)	(11)%
Net realized gas price, excluding hedges	$ 5.04	$ 4.55	(11)%
Net Oil Production:			
Appalachian oil (Bbls)	28,974	21,186	37%
Permian oil (Bbls)	91,817	56,969(b)	61%
South Texas oil (Bbls)	6,818(a)	—(a)(c)	—
Mississippi oil (Bbls)	26,836(a)	—(a)	—
Total oil production (Bbls)	154,445	78,155	98%
Average Appalachian daily oil production (Bbls/day)	318	233	37%
Average Permian daily oil production (Bbls/day)	1,009	626(b)	61%
Average South Texas daily oil production (Bbls/day)	75(a)	—(a)(c)	—
Average Mississippi daily oil production (Bbls/day)	295(a)	—(a)	—
Average Vanguard daily oil production (Bbls/day)	1,697	859	98%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$ 75.87(d)	$ 75.95(d)	—%
Net realized oil price, excluding hedges	$ 71.37	$ 54.93	30%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	304,627	124,656(b)	144%
South Texas natural gas liquids (Gal)	1,808,944	495,607(a)(c)	265%
Total natural gas liquids production (Gal)	2,113,571	620,263	241%
Average Permian daily natural gas liquids production (Gal/day)	3,347	1,370(b)	144%
Average South Texas daily natural gas liquids production (Gal/day)	19,879	5,446(c)	265%
Average Vanguard daily natural gas liquids production (Gal/day)	23,226	6,816	241%
Average Net Realized Natural Gas Liquids Sales Price per Gal	$ 0.96	$ 0.56	71%

(a) South Texas area includes production from the Dos Hermanos, Sun TSH and Parker Creek acquisitions. The Parker Creek acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the three month period ended June 30, 2010, and no operations are included in the three month period ended June 30, 2009. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the South Texas area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 4,878 Mcf/day of natural gas and 84 Bbls/day of oil. The average daily production for the Mississippi area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 440 Bbls/day of oil.

(b) The Ward County acquisition closed on December 2, 2009 and, as such, no operations are included in the three month period ended June 30, 2009.

(c) The Sun TSH acquisition closed on August 17, 2009 and, as such, no operations are included in the three month period ended June 30, 2009.

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

The increase in natural gas, natural gas liquids and oil sales during the three months ended June 30, 2010 compared to the same period in 2009 was due primarily to the increases in production. Total production increased by 55% on a Mcfe basis. The increase in production for the three months ended June 30, 2010 over the comparable period in 2009 was primarily attributable to the impact from the Sun TSH, Ward County and Parker Creek acquisitions completed in August 2009, December 2009 and May 2010, respectively. In Appalachia, we experienced a 6% decrease in natural gas production which was largely offset by a 37% increase in oil production during the three months ended June 30, 2010 compared to the same period in 2009. The decrease in natural gas production is largely attributable to our decision to drill only one well in 2010 due to low natural gas prices. The 37% increase in Appalachian oil production was primarily due to our focus on recompleting to oil zones on existing natural gas wells in 2009, which negatively affected the amount of natural gas produced in 2010.

Hedging and Price Risk Management Activities

During the three months ended June 30, 2010, the Company recognized a $6.5 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $0.09 million loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. During the three months ended June 30, 2010, the Company recognized $0.5 million in losses on commodity cash flow hedges that meet the criteria for cash flow hedge accounting. These amounts relate to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. The loss on commodity cash flow hedges for the three months ended June 30, 2010 relates to the amount that settled in 2010 and has been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because the majority of our hedges are not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our consolidated statement of operations. However, these fair value changes that are reflected in the consolidated statement of operations only reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel and other customary charges. Lease operating expenses in Appalachia also include a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. This fee was temporarily increased to $95 per well per month for the period beginning March 1, 2009 through December 31, 2009 pursuant to an amendment to an agreement whereunder Vinland provided well-tending services on Vanguard owned wells under a turnkey pricing contract. In addition, we pay a $0.25 per Mcf and $0.55 per Mcf gathering and compression charge for production from wells drilled pre and post January 1, 2007, respectively, to Vinland pursuant to a gathering and compression agreement with Vinland. This gathering and compression agreement was amended for the period beginning March 1, 2009 through December 31, 2009 to provide for a temporary fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. Both temporary amendments expired on December 31, 2009 and all the terms of the agreements reverted back to the original agreements. Lease operating expenses increased by $1.9 million to $4.6 million for the three months ended June 30, 2010 as compared to the three months ended June 30, 2009, of which $1.1 million related primarily to the Sun TSH, Ward County and Parker Creek acquisitions and $0.8 million related to increased lease operating expenses for wells in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $5.7 million for the three months ended June 30, 2010 from approximately $2.6 million for the three months ended June 30, 2009 due primarily to additional depletion recorded on natural gas and oil properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended June 30, 2010 decreased $1.8 million as compared to the three months ended June 30, 2009 principally due to a decrease in non-cash compensation charges related to the grant of restricted Class B units to officers and an employee, the grant of phantom units to officers and the grant of common units to board members and employees. Non-cash compensation charges declined $1.6 million to $0.2 million for the three months ended June 30, 2010. All other cash selling, general and administrative expenses decreased $0.2 million during the three months ended June 30, 2010 as compared to the same period in 2009 principally due to a reduction in legal and professional fees.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $1.0 million for the three months ended June 30, 2010 as compared to the same period in 2009 as a result of increased natural gas, natural gas liquids and oil sales. Texas margin and other corporate taxes increased by $0.3 million and ad valorem taxes increased by $0.2 million primarily due to the taxes on natural gas and oil properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

Interest expense increased to $1.5 million for the three months ended June 30, 2010 compared to $1.0 million for the three months ended June 30, 2009 primarily due to higher average outstanding debt during the three months ended June 30, 2010.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Revenues

Natural gas, natural gas liquids and oil sales increased $20.9 million to $39.5 million during the six months ended June 30, 2010 as compared to the same period in 2009. The key revenue measurements were as follows:

	Six Months Ended June 30,		Percentage Increase (Decrease)
	2010	2009	
Net Natural Gas Production:			
Appalachian gas (MMcf)	1,436	1,599	(10)%
Permian gas (MMcf)	179	96(b)	87%
South Texas gas (MMcf)	860(a)	428(a)(c)	101%
Total natural gas production (MMcf)	2,475	2,123	17%
Average Appalachian daily gas production (Mcf/day)	7,935	8,837	(10)%
Average Permian daily gas production (Mcf/day)	990	530(b)	87%
Average South Texas daily gas production (Mcf/day)	4,750(a)	2,363(a)(c)	101%
Average Vanguard daily gas production (Mcf/day)	13,675	11,730	17%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$ 10.10(d)	$ 11.13(d)	(9)%
Net realized gas price, excluding hedges	$ 5.62	$ 5.07	11%
Net Oil Production:			
Appalachian oil (Bbls)	61,330	37,697	63%
Permian oil (Bbls)	188,238	117,649(b)	60%
South Texas oil (Bbls)	10,452(a)	—(a)(c)	—
Mississippi oil (Bbls)	26,836(a)	—(a)	—
Total oil production (Bbls)	286,856	155,346	85%
Average Appalachian daily oil production (Bbls/day)	339	208	63%
Average Permian daily oil production (Bbls/day)	1,040	650(b)	60%
Average South Texas daily oil production (Bbls/day)	57(a)	—(a)(c)	—
Average Mississippi daily oil production (Bbls/day)	148(a)	—(a)	—
Average Vanguard daily oil production (Bbls/day)	1,584	858	85%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$ 76.52(d)	$ 73.26(d)	4%
Net realized oil price, excluding hedges	$ 72.12	$ 46.18	56%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	684,465	235,200(b)	191%
South Texas natural gas liquids (Gal)	3,826,338	831,236(a)(c)	360%
Total natural gas liquids production (Gal)	4,510,803	1,066,436	323%
Average Permian daily natural gas liquids production (Gal/day)	3,782	1,299(b)	191%
Average South Texas daily natural gas liquids production (Gal/day)	21,140	4,592(c)	360%
Average Vanguard daily natural gas liquids production (Gal/day)	24,922	5,891	323%
Average Net Realized Natural Gas Liquids Sales Price per Gal	$ 1.09	$ 0.63	73%

(a) South Texas area includes production from the Dos Hermanos, Sun TSH and Parker Creek acquisitions. The Parker Creek acquisition closed on May 20, 2010 and, as such, only one month and eleven days of operations are included in the six month period ended June 30, 2010, and no operations are included in the six month period ended June 30, 2009. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the South Texas area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 4,908Mcf/day of natural gas and 76 Bbls/day of oil. The average daily production for the Mississippi area, calculated using the actual number of days for the Parker Creek acquisition from the closing date to the end of the reported period, was 440 Bbls/day of oil.

(b) The Ward County acquisition closed on December 2, 2009 and, as such, no operations are included in the six month period ended June 30, 2009.

(c) The Sun TSH acquisition closed on August 17, 2009 and, as such, no operations are included in the six month period ended June 30, 2009.

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

The increase in natural gas, natural gas liquids and oil sales during the six months ended June 30, 2010 compared to the same period in 2009 was due primarily to the increases in commodity prices and an increase in production. We experienced an 11% increase in the average realized natural gas sales price received (excluding hedges) and a 56% increase in the average realized oil price (excluding hedges). Additionally, our total production increased by 51% on a Mcfe basis. The increase in production for the six months ended June 30, 2010 over the comparable period in 2009 was primarily attributable to the impact from the Sun TSH, Ward County and Parker Creek acquisitions completed in August 2009, December 2009 and May 2010, respectively. In Appalachia, we experienced a 10% decrease in natural gas production which was partially offset by a 63% increase in oil production during the six months ended June 30, 2010 compared to the same period in 2009 for a net production decline of 1% on a Mcfe basis. The decrease in natural gas production is largely attributable to our decision to drill only one well in 2010 due to low natural gas prices. The 63% increase in Appalachian oil production was primarily due to our focus on recompleting to oil zones on existing natural gas wells in 2009, which negatively affected the amount of natural gas produced in 2010.

Hedging and Price Risk Management Activities

During the six months ended June 30, 2010, the Company recognized a $11.8 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $10.7 million gain related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. During the six months ended June 30, 2010, the Company recognized $1.6 million in losses on commodity cash flow hedges that meet the criteria for cash flow hedge accounting. These amounts relate to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. The loss on commodity cash flow hedges for the six months ended June 30, 2010 relates to the amount that settled in 2010 and has been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and us paying the counterparty when commodity prices are above the hedged price. In either case, the impact on our operating cash flow is approximately the same. However, because the majority of our hedges are not designated as cash flow hedges, there can be a significant amount of volatility in our earnings when we record the change in the fair value of all of our derivative contracts. As commodity prices fluctuate, the fair value of those contracts will fluctuate and the impact is reflected as a non-cash, unrealized gain or loss in our consolidated statement of operations. However, these fair value changes that are reflected in the consolidated statement of operations only reflect the value of the derivative contracts to be settled in the future and do not take into consideration the value of the underlying commodity. If the fair value of the derivative contract goes down, it means that the value of the commodity being hedged has gone up, and the net impact to our cash flow when the contract settles and the commodity is sold in the market will be approximately the same. Conversely, if the fair value of the derivative contract goes up, it means the value of the commodity being hedged has gone down and again the net impact to our operating cash flow when the contract settles and the commodity is sold in the market will be approximately the same for the quantities hedged.

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel and other customary charges. Lease operating expenses in Appalachia also include a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. This fee was temporarily increased to $95 per well per month for the period beginning March 1, 2009 through December 31, 2009 pursuant to an amendment to an agreement whereunder Vinland provided well-tending services on Vanguard owned wells under a turnkey pricing contract. In addition, we pay a $0.25 per Mcf and $0.55 per Mcf gathering and compression charge for production from wells drilled pre and post January 1, 2007, respectively, to Vinland pursuant to a gathering and compression agreement with Vinland. This gathering and compression agreement was amended for the period beginning March 1, 2009 through December 31, 2009 to provide for a temporary fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. Both temporary amendments expired on December 31, 2009 and all the terms of the agreements reverted back to the original agreements. Lease operating expenses increased by $2.8 million to $8.7 million for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009, of which $1.5 million related primarily to the Sun TSH, Ward County and Parker Creek acquisitions and $1.3 million related to increased lease operating expenses for wells in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $10.0 million for the six months ended June 30, 2010 from approximately $6.4 million for the six months ended June 30, 2009 due primarily to additional depletion recorded on natural gas and oil properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

An impairment of natural gas and oil properties in the amount of $63.8 million was recognized during the six months ended June 30, 2009 as the unamortized cost of natural gas and oil properties exceeded the sum of the estimated future net revenues from proved properties using period-end prices, discounted at 10% and the lower of cost or fair value of unproved properties as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The impairment calculation did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allows the inclusion of derivatives designated as cash flow hedges. No impairment of natural gas and oil properties was necessary at June 30, 2010.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the six months ended June 30, 2010 decreased $3.6 million as compared to the six months ended June 30, 2009 principally due to a decrease in non-cash compensation charges related to the grant of restricted Class B units to officers and an employee, the grant of phantom units to officers and the grant of common units to board members and employees. Non-cash compensation charges declined $3.5 million to $0.5 million for the six months ended June 30, 2010. All other cash selling, general and administrative expenses decreased $0.1 million during the six months ended June 30, 2010 as compared to the same period in 2009 principally due to lower legal and professional fees, offset by higher compensation related expenses.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $1.9 million for the six months ended June 30, 2010 as compared to the same period in 2009 as a result of increased natural gas, natural gas liquids and oil sales. Texas margin and other corporate taxes increased by $0.3 million and ad valorem taxes increased by $0.2 million primarily due to the taxes on natural gas and oil properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

Interest expense increased to $2.8 million for the six months ended June 30, 2010 compared to $2.0 million for the six months ended June 30, 2009 primarily due to higher average outstanding debt during the six months ended June 30, 2010.

Critical Accounting Policies and Estimates

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

As of June 30, 2010, our critical accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2009.

Recently Adopted Accounting Pronouncements

In June 2009, the FASB issued guidance to change financial reporting by enterprises involved with variable interest entities ("VIEs"). The standard replaces the quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a VIE with an approach focused on identifying which enterprise has the power to direct the activities of a VIE and the obligation to absorb losses of the entity or the right to receive the entity's residual returns. This standard was effective for us on January 1, 2010. We do not have any interests in variable interest entities; therefore, this standard did not have any impact on our consolidated financial statements.

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance was effective for us on January 1, 2010 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard did not impact our results of operations, cash flows or financial position.

New Pronouncements Issued But Not Yet Adopted

In March 2010, the FASB issued authoritative guidance intended to clarify the scope exception related to embedded credit derivative features related to the transfer of credit risk in the form of subordination of one financial instrument to another. The guidance addresses how to determine which embedded credit derivative features, including those in collateralized debt obligations and synthetic collateralized debt obligations, are considered to be embedded derivatives that should not be analyzed under Accounting Standards Codification Topic 815, "Derivatives and Hedging" Subtopic 15-25 for potential bifurcation and separate accounting. This guidance is effective for each reporting entity at the beginning of its fiscal quarter beginning after June 15, 2010. We do not have any embedded credit derivative features with respect to our financial instruments; therefore, this standard is not expected to have any impact on our consolidated financial statements.

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

Liquidity and Capital Resources

Disruption to Functioning of Capital Markets

Multiple events during 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

Natural gas, natural gas liquids and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the crude oil spot price per barrel for the period between January 1, 2010 and June 30, 2010 ranged from a high of $86.54 to a low of $71.15 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2010 to June 30, 2010 ranged from a high of $6.01 to a low of $3.84. As of July 27, 2010, the crude oil spot price per barrel was $77.46 and the NYMEX natural gas spot price per MMBtu was $4.68.

Overview

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and more recently the public equity markets for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of natural gas and oil properties; however, we expect to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we will continually monitor the capital resources available to us to meet future financial obligations, planned capital expenditures, acquisition capital and distributions to our unitholders. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us and our success in drilling for and acquiring additional reserves. We expect to fund our drilling capital expenditures and distributions to unitholders with cash flow from operations, while funding any acquisition capital expenditures that we might incur with borrowings under our reserve-based credit facility and publicly offered equity or debt, depending on market conditions. As of August 2, 2010, we have $69.3 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future natural gas, natural gas liquids and oil prices) from our proved natural gas, natural gas liquids and oil reserves. If commodity prices decline in the future and banks lower their internal projections of natural gas, natural gas liquids and oil prices, it is possible that we will be subject to a decrease in our borrowing base availability in the future. Our next borrowing base redetermination is scheduled for October 2010 utilizing our September 30, 2010 reserve report. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold. At June 30, 2010, our borrowings represented 72% of our borrowing base. Absent accretive acquisitions, to the extent available after unitholder distributions, debt service, and capital expenditures, it is our current intention to utilize our excess cash flow during 2010 to reduce our borrowings under our reserve-based credit facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient for the conduct of our business and operations for the foreseeable future.

Cash Flow from Operations

Net cash provided by operating activities was $31.5 million during the six months ended June 30, 2010, compared to $21.5 million during the six months ended June 30, 2009. The increase in cash provided by operating activities during the six months ended June 30, 2010 as compared to the same period in 2009 was substantially generated from increased production volumes related to the Sun TSH, Ward County and Parker Creek acquisitions which had been hedged at favorable prices generating significant realized gains on commodity derivative contracts. Changes in working capital decreased total cash flows by $3.0 million in 2010 compared to decreasing total cash flows by $2.2 million in 2009. Contributing to the decrease in the level of cash provided by operating activities during 2010 was a $3.5 million decrease in accrued expenses that resulted primarily from the timing effects of payments for amounts related to the phantom units granted to officers. Both impairment charges and unrealized derivative gains and losses are accounted for as non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the six months ended June 30, 2010 or 2009.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas, natural gas liquids and oil prices. Natural gas, natural gas liquids and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather, and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, as well as the prices received for production. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we use a combination of fixed-price swaps and NYMEX collars and put options to reduce our exposure to the volatility in natural gas, natural gas liquids and oil prices. See Note 4 in Notes to Consolidated Financial Statements and Part 1—Item 3—Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk for details about derivatives in place through 2011 for natural gas and 2014 for oil.

Cash Flow from Investing Activities

Cash used in investing activities was approximately $121.1 million for the six months ended June 30, 2010, compared to $2.2 million during the same period in 2009. The increase in cash used in investing activities was primarily attributable to $112.3 million for the acquisition of natural gas and oil properties in the Parker Creek acquisition, $7.6 million for the drilling and development of natural gas and oil properties and $0.9 million for prepayments for the drilling and development of natural gas and oil properties as compared to $1.9 million for the drilling and development of natural gas and oil properties during the six months ended June 30, 2009.

Cash Flow from Financing Activities

Cash provided by financing activities was approximately $91.4 million for the six months ended June 30, 2010, compared to cash used of $15.6 million for the six months ended June 30, 2009. During the six months ended June 30, 2010, total net borrowings under our reserve-based credit facility were $41.9 million and total proceeds from our public equity offering completed in May 2010 were $71.4 million. Offsetting the cash provided by financing activities during the six months ended June 30, 2010, was cash used of $19.8 million for distributions to unitholders. Cash used in financing activities during the six months ended June 30, 2009, included $2.5 million in net repayments under our reserve-based credit facility and $12.6 million used in distribution to unitholders.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. Our reserve-based credit facility was amended and restated in February 2008 to extend the maturity date from January 2011 to March 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and the Bank of Nova Scotia. The increase in the borrowing base was principally the result of inclusion of the reserves related to the Permian Basin acquisition in January 2008. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. As of October 22, 2008, our reserve-based credit facility was amended and restated to increase the borrowing base to $175.0 million and add one lender, BBVA Compass Bank. The increase in the borrowing base was principally the result of inclusion of the reserves related to the acquisition of certain natural gas and oil properties in July 2008. In February 2009, a third amendment was entered into which amended covenants to allow us to repurchase up to $5.0 million of our own units. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. In June 2010, we entered into the Second Amendment to Second Amended and Restated Credit Agreement, which (1) increased the borrowing base to $240 million, (2) allows us to enter into commodity price hedges with respect to the acquired production upon signing a purchase and sale agreement, (3) added a new lender, Credit Agricole Corporate and Investment Bank, and (4) allows us to hedge up to 85% of the projected oil and gas production from total proved reserves. Previously, our hedging was limited to 95% of the projected oil and gas production from proved developed producing reserves. The other terms and conditions of the reserve-based credit facility remained substantially the same. At June 30, 2010, we had $171.7 million outstanding under our reserve-based credit facility and as of August 2, 2010 we have $69.3 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future natural gas, natural gas liquids and oil prices) from our proved natural gas, natural gas liquids and oil reserves. In June 2010, our borrowing base was set at $240.0 million. Our next borrowing base redetermination is scheduled for October 2010 utilizing our September 30, 2010 reserve report. If commodity prices decline in the future and banks lower their internal projections of natural gas, natural gas liquids and oil prices, it is possible that we will be subject to decreases in our borrowing base availability in the future. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold. At June 30, 2010, our borrowings represented 72% of our borrowing base. Absent accretive acquisitions, to the extent available after unitholder distributions, debt service and capital expenditures, it is our current intention to utilize our excess cash flow during 2010 to reduce our borrowings under our reserve-based credit facility.

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

At our election, interest is determined by reference to:

- the London interbank offered rate, or LIBOR, plus an applicable margin between 2.25% and 3.00% per annum; or
- a domestic bank rate plus an applicable margin between 1.25% and 2.00% per annum.

As of June 30, 2010, we have elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

The reserve-based credit facility contains various covenants that limit our ability to:

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

The reserve-based credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income (which is equal to our Adjusted EBITDA), and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0;
- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under ASC Topic 815, which includes the current portion of derivative contracts; and
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 3.5 to 1.0.

We have the ability to borrow under the reserve-based credit facility to pay distributions to unitholders as long as there has not been a default or event of default and if the amount of borrowings outstanding under our reserve-based credit facility is less than 90% of the borrowing base.

We believe that we are in compliance with the terms of our reserve-based credit facility. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Among others, each of the following will be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $2.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and
- a change of control, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Securities Exchange Act of 1934 and the rules of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests other than by Majeed S. Nami or his affiliates, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Off-Balance Sheet Arrangements

At June 30, 2010, we did not have any off-balance sheet arrangements that have, or are reasonably likely to have, an effect on our financial position or results of operations.

Contingencies

We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. As of June 30, 2010, there were no loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of June 30, 2010 is provided in the following table (in thousands):

	Payments Due by Year						
	2010	2011	2012	2013	2014	After 2014	Total
Management base salaries	$ 415	$ 830	$ 830	$ 97	$ —	$ —	$ 2,172
Asset retirement obligations	—	479	85	135	133	4,179	5,011
Derivative liabilities	3,169	1,173	1,502	945	1,386	3,880	12,055
Long-term debt (1)	—	—	171,700	—	—	—	171,700
Operating leases	58	122	130	33	—	—	343
Total	$ 3,642	$ 2,604	$ 174,247	$ 1,210	$ 1,519	$ 8,059	$ 191,281

(1) This table does not include interest to be paid on the principal balances shown as the interest rates on the reserve-based credit facility are variable.

Non-GAAP Financial Measure

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) plus:

- Net interest expense, including write-off of deferred financing fees and realized gains and losses on interest rate derivative contracts;
- Depreciation, depletion, and amortization (including accretion of asset retirement obligations);
- Impairment of natural gas and oil properties;
- Amortization of premiums paid on derivative contracts;
- Amortization of value on derivative contracts acquired;
- Unrealized gains and losses on other commodity and interest rate derivative contracts;
- Deferred taxes; and
- Unit-based compensation expense.

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

Our Adjusted EBITDA should not be considered as an alternative to net income, operating income, cash flow from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

For the three months ended June 30, 2010 as compared to the three months ended June 30, 2009, Adjusted EBITDA increased 44%, from $13.3 million to $19.1 million. For the six months ended June 30, 2010 as compared to the six months ended June 30, 2009, Adjusted EBITDA increased 45%, from $25.9 million to $37.6 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income (loss)	$ 3,905	$ (6,768)	$ 25,608	$ (56,733)
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	2,006	1,377	3,812	2,726
Depreciation, depletion, amortization, and accretion	5,713	2,645	9,951	6,428
Impairment of natural gas and oil properties	—	—	—	63,818
Amortization of premiums paid on derivative contracts	493	890	998	1,818
Amortization of value on derivative contracts acquired	558	217	1,168	754
Unrealized (gains) losses on other commodity and interest rate derivative contracts	524	13,096	(10,036)	3,310
Loss on acquisition of natural gas and oil properties	5,680	—	5,680	—
Deferred taxes	31	(4)	(49)	(201)
Unit-based compensation expense	212	876	466	1,763
Unrealized fair value of phantom units granted to officers	21	951	48	2,252
Adjusted EBITDA	$ 19,143	$ 13,280	$ 37,646	$ 25,935

Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our natural gas, natural gas liquids and oil production. Realized pricing is primarily driven by the Columbia Gas Appalachian Index (“TECO Index”), Henry Hub and Houston Ship Channel prices for natural gas production and the West Texas Intermediate Light Sweet price for oil production. Pricing for natural gas, natural gas liquids and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level, the borrowing base can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes.

Furthermore, the risk that we will be required to write down the carrying value of our natural gas and oil properties increases when oil and gas prices are low or volatile. In addition, write downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. No ceiling test impairment was necessary for the three months ended June 30, 2010 or 2009 or for the six months ended June 30, 2010.

We enter into derivative contracts with respect to a portion of our projected natural gas and oil production through various transactions that mitigate the volatility of future prices received. These transactions may include price swaps whereby we will receive a fixed-price for our production and pay a variable market price to the contract counterparty. Additionally, we may acquire put options for which we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. As each monthly contract settles, we receive the excess, if any, of the fixed floor over the floating rate. In addition to these fixed price swap derivatives, we may sell calls and give counterparties the option to extend certain swaps into subsequent years at specified prices. Proceeds from the sale of the calls or extendable options may be used to improve the fixed price on the fixed price swaps. Furthermore, we may enter into collars where we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor on a notional quantity. In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management’s view on future commodity pricing. The amount of natural gas and oil production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Typically, management intends to hedge 70% to 85% of projected production for a three year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. It is never management’s intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At June 30, 2010, the fair value of commodity derivative contracts was an asset of approximately $30.8 million, of which $21.3 million settles during the next twelve months.

The following table summarizes commodity derivative contracts in place at June 30, 2010:

	July 1, - December 31, 2010	Year 2011	Year 2012	Year 2013	Year 2014
Gas Positions:					
Fixed Price Swaps:					
Notional Volume (MMBtu)	2,241,930	3,328,312	—	—	—
Fixed Price ($/MMBtu)	$ 8.63	$ 7.83	$ —	$ —	$ —
Collars:					
Notional Volume (MMBtu)	901,600	1,933,500	—	—	—
Floor Price ($/MMBtu)	$ 7.70	$ 7.34	$ —	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.93	$ 8.44	$ —	$ —	$ —
Total:					
Notional Volume (MMBtu)	3,143,530	5,261,812	—	—	—
Oil Positions:					
Fixed Price Swaps:					
Notional Volume (Bbls)	181,200	443,250	347,700	296,400	209,875
Fixed Price ($/Bbl)	$ 87.16	$ 87.94	$ 90.03	$ 89.84	$ 94.37
Collars:					
Notional Volume (Bbls)	—	—	45,750	45,625	—
Floor Price ($/Bbl)	$ —	$ —	$ 80.00	$ 80.00	$ —
Ceiling Price ($/Bbl)	$ —	$ —	$ 100.25	$ 100.25	$ —
Total:					
Notional Volume (Bbls)	181,200	443,250	393,450	342,025	209,875

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

	Year 2012	Year 2013	Year 2014	Year 2015
Swaptions:				
Notional Volume (Bbls)	45,750	32,100	127,750	292,000
Weighted Average Fixed Price ($/Bbl)	$ 90.40	$ 95.00	$ 95.00	$ 95.63

Interest Rate Risks

At June 30, 2010, we had debt outstanding of $171.7 million, which incurred interest at floating rates based on LIBOR in accordance with our reserve-based credit facility and, if the debt remains the same, a 1% increase in LIBOR would result in an estimated $0.7 million increase in annual interest expense after consideration of the interest rate swaps discussed below.

We enter into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. The Company records changes in the fair value of its interest rate derivatives in current earnings under unrealized gains (losses) on interest rate derivative contracts. During 2008, the company chose to de-designate its interest rate swaps as cash flow hedges as the terms of new contracts entered into in August 2008 no longer matched the terms of the original contracts, thus causing the interest rate hedges to be ineffective. The net unrealized gain related to the de-designated cash flow hedges is reported in accumulated other comprehensive income and later reclassified to earnings in the month in which the transactions settle.

The following summarizes information concerning our positions in open interest rate derivative contracts at June 30, 2010 (in thousands):

	Notional Amount	Fixed Libor Rates
Period:		
July 1, 2010 to December 18, 2010	$ 10,000	1.50%
July 1, 2010 to December 20, 2010	$ 10,000	1.85%
July 1, 2010 to March 31, 2011	$ 20,000	2.08%
July 1, 2010 to December 10, 2012	$ 20,000	3.35%
July 1, 2010 to January 31, 2013	$ 20,000	2.38%
July 1, 2010 to January 31, 2013	$ 20,000	2.66%

Counterparty Risk

At June 30, 2010, based upon all of our open derivative contracts shown above and their respective mark to market values, we had the following current and long-term derivative assets and liabilities shown by counterparty with their current S&P financial strength rating in parentheses (in thousands):

	Citibank, N.A. (A+)	BNP Paribas (AA)	The Bank of Nova Scotia (AA-)	Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA)	BBVA Compass (A)	Total
Current Assets	$ 5,367	$ 12,792	$ 1,270	$ 1,679	$ 146	$ 21,254
Current Liabilities	(47)	—	(65)	(241)	—	(353)
Long-Term Assets	2,264	5,314	1,660	—	308	9,546
Long-Term Liabilities	—	(1,767)	(786)	—	—	(2,553)
Total Amount Due from/(Owed To) Counterparty at June 30, 2010	$ 7,584	$ 16,339	$ 2,079	$ 1,438	$ 454	$ 27,894

We net derivative assets and liabilities for counterparties where we have a legal right of offset.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report on Form 10-Q, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) was evaluated by our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, in accordance with rules of the Securities Exchange Act of 1934, as amended. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of June 30, 2010 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to management and recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Control over Financial Reporting

On May 20, 2010, we completed the acquisition of certain natural gas and oil properties in Mississippi, Texas and New Mexico. Pursuant to this transaction, we have outsourced our production accounting for these properties to the same third party that handles the production accounting for the Permian Basin and our other South Texas properties. As a result, there were no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or government proceedings against us, or contemplated to be brought against us, under the various environmental statutes to which we are subject.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed below or elsewhere in this Form 10-Q or our other SEC filings, could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our units, please refer to Part I- Item 1A- Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2009 as supplemented by the risk factors set forth below. There has been no material change in the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2009 other than those set forth below.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for producers to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Any such added regulation could lead to operational delays, increased operating costs and additional regulatory burdens, and reduced production of natural gas and oil, which could adversely affect our revenues and results of operations.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas, natural gas liquids and oil we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

On December 15, 2009, the U.S. Environmental Protection Agency, or "EPA" published its final findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. In March 2010, the EPA announced a proposed rulemaking that would expand its final rule on reporting of greenhouse gas emissions to include owners and operators of petroleum and natural gas systems. If the proposed rule is finalized in its current form, monitoring of those newly covered sources would commence on January 1, 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Further, Congress is presently considering and almost one-half of the states have adopted legislation that seeks to control of reduce emissions of greenhouse gases from a wide range of sources. Any such legislation could adversely affect demand for the natural gas, natural gas liquids and oil that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations and cause us to incur significant costs in preparing for or responding to those effects.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment . The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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

During the three months ended June 30, 2010 one of our wholly-owned subsidiaries purchased 10,000 of our common units on the open market at the prevailing market price. The following table summarizes the unit purchases that occurred during the three months ended June 30, 2010:

Period	Number of common units repurchased	Average price paid per common unit
April 1, 2010 to April 30, 2010	—	$ N/A
May 1, 2010 to May 31, 2010	10,000	$ 20.58
June 1, 2010 to June 30, 2010	—	$ N/A
Total common units purchased	10,000	$ 20.58

Item 3. Defaults Upon Senior Securities

None.

Item 4. Reserved

Item 5. Other Information

None.

Item 6. Exhibits

EXHIBIT INDEX

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

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.1	Employment Agreement, dated June 18, 2010, by and between Britt Pence, VNR Holdings, LLC and Vanguard Natural Resources, LLC	Filed herewith
10.2	Restricted Unit Award Agreement, by and between Vanguard Natural Resources, LLC and Britt Pence	Filed herewith
10.3	Phantom Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC and Britt Pence	Filed herewith
10.4	Asset Purchase Agreement, dated April 30, 2010, by and between Alpine Gas Investors, LP and Vanguard Permian, LLC	Form 8-K, filed May 5, 2010 (File No. 001-33756)
10.5	Second Amendment to Second Amended and Restated Credit Agreement, dated June 1, 2010, among Vanguard Natural Gas, LLC, Citibank, N.A. , Existing Lenders (as defined therein), and Credit Agricole Corporate and Investment Bank	Form 8-K, filed June 4, 2010 (File No. 001-33756)
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith

SIGNATURE

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

VANGUARD NATURAL RESOURCES, LLC
(Registrant)

Date: August 4, 2010

/s/ Richard A. Robert

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

Exhibit 10.1

EMPLOYMENT AGREEMENT

BRITT PENCE

This **EMPLOYMENT AGREEMENT**, dated June 18, 2010 but effective as of May 15, 2010, is by and between VNR Holdings, LLC, a Delaware limited liability company ("***VNR***"), Vanguard Natural Resources, LLC, a Delaware limited liability company ("***Parent***") and Britt Pence (the "***Executive***").

WHEREAS, Parent, VNR and Executive previously entered into that certain Employment Agreement effective May 15, 2007 (the "***Original Agreement***"), which governed the Executive's employment role as the Vice President, Engineering of VNR and the Parent;

WHEREAS, VNR and Parent desire to continue to employ Executive and Executive desires to continue to be employed in the new employment role of Senior Vice President of Operations of VNR and the Parent;

WHEREAS, the parties desire to set forth in writing the terms and conditions of their understandings and agreements in this new Employment Agreement (this "***Agreement***");

NOW, **THEREFORE**, in consideration of the mutual covenants and obligations contained herein, VNR hereby agrees to employ Executive and Executive hereby accepts such employment upon the terms and conditions set forth in this Agreement:

1. **Employment Period.**

(a) Subject to Section 6, VNR hereby agrees to employ Executive, and Executive hereby agrees to be employed by VNR, in accordance with the terms and provisions of this Agreement, for the period commencing as of the date hereof (the "***Effective Date***") and ending on May 15, 2013 (the "***Employment Period***"); provided, however, that the Employment Period shall automatically be renewed and extended for an additional period of twelve (12) months commencing on May 15, 2013 and expiring on May 15, 2014, and on each successive May 15 thereafter, unless at least ninety (90) days prior to the ensuing expiration date (but no more than twelve (12) months prior to such expiration date), VNR or Executive shall have given ninety (90) days written notice to the other that it or he, as applicable, does not wish to extend this Agreement (a "***Non-Renewal Notice***"). The term "***Employment Period***," as utilized in this Agreement, shall refer to the Employment Period as so automatically extended.

(b) During the term of Executive's employment with VNR, Executive shall serve as the Senior Vice President of Operations of VNR and the Parent (together, the "***Company***") and in so doing, shall report to the Company's Chief Executive Officer (the "***CEO***"). Executive shall have supervision and control over, and responsibility for, such management and operational functions of the Company currently assigned to such positions, and shall have such other powers and duties (including holding officer positions with the Company and one or more subsidiaries of the Company) as may from time to time be prescribed by the CEO, so long as such powers and duties are reasonable and customary for the Senior Vice President of Operations of an enterprise comparable to the Company.

(c) During the term of Executive's employment with VNR, and excluding any periods of vacation and sick leave to which Executive is entitled, Executive agrees to devote substantially all of his business time to the business and affairs of VNR and, to the extent necessary to discharge the responsibilities assigned to Executive hereunder, to use Executive's reasonable best efforts to perform faithfully, effectively and efficiently such responsibilities. During the term of Executive's employment with VNR, it shall not be a violation of this Agreement for Executive to (i) serve on corporate, civic or charitable boards or committees, (ii) deliver lectures or fulfill speaking engagements and (iii) manage personal investments, so long as such activities do not materially interfere with the performance of Executive's responsibilities as an employee of the Company in accordance with this Agreement.

(d) The parties expressly acknowledge that any performance of Executive's responsibilities hereunder shall necessitate, and the Company shall provide, access to or the disclosure of Confidential Information (as defined in Section 10(a) below) to Executive and that Executive's responsibilities shall include the development of the Company's goodwill through Executive's contacts with the Company's customers and suppliers.

2. **Compensation**.

(a) *Base Salary*. VNR shall pay Executive an annual base salary ("***Base Salary***") at the rate of $260,000 for the period commencing on the Effective Date and ending on the Date of Termination (as defined below). The CEO will review Executive's Base Salary on an annual basis beginning on April 30, 2011, and may increase the Base Salary in such amounts or percentages as the CEO shall deem appropriate, if any. The CEO may not decrease the Executive's annual Base Salary without his prior written approval. Base Salary shall be payable in accordance with the ordinary payroll practices of VNR, but in no event shall the Base Salary be paid to Executive less frequently than monthly. The term "Base Salary" as used in this Agreement shall refer to the Base Salary as it may be so adjusted from time to time.

(b) *Annual Bonus*. Executive shall be eligible to receive an annual bonus (the "***Annual Bonus***") based upon VNR's unit price performance and/or the achievement of annual performance targets; such terms and conditions of Executive's Annual Bonus for each calendar year within the Employment Period are set forth in Appendix A hereto.

3. **Employee Benefits**.

(a) During the Employment Period, VNR shall provide Executive with coverage under all employee pension and welfare benefit programs, plans and practices, which VNR makes available to its senior executives (including, without limitation, participation in health, dental, group life, disability, retirement and all other plans and fringe benefits to the extent generally provided to such senior executives), commensurate with his position in the Company, to the extent permitted under the employee benefit plan or program, and in accordance with the terms of the program and/or plan.

(b) Executive shall be entitled to vacation time generally available to executive employees of VNR (but no less than fifteen (15) business days paid vacation in each full calendar year). Such vacation time shall accrue at a rate of one and a quarter (1.25) vacation days for each calendar month worked; provided, however, that during any given calendar year, Executive shall be able to take vacation days that will accrue during that calendar year, even if such days have not yet accrued. A maximum of five (5) business days of accrued but unused vacation may be carried over from one calendar year to the next.

(c) Executive is authorized to incur reasonable expenses in carrying out his duties and responsibilities under this Agreement and promoting the business of the Company, including, without limitation, reasonable expenses for travel, lodgings, entertainment and similar items related to such duties and responsibilities. VNR will promptly reimburse Executive for all such expenses upon presentation by Executive of appropriately itemized and approved (consistent with VNR's policy) accounts of such expenditures, in accordance with the Company's expense reimbursement policy; provided, however, that in no event shall the expense reimbursement be made after the last day of the taxable year following the year in which the expense was incurred by Executive, although in the event that the reimbursement would constitute taxable income to Executive, such reimbursements will be paid no later than March 15th of the calendar year following the calendar year in which the expense was incurred. No reimbursement or expenses eligible for reimbursement in any taxable year shall affect the expenses eligible for reimbursement in any other taxable year, nor may the right to receive a reimbursement of expenses be subject to liquidation or exchanged for another benefit.

4. **Restricted Units and Phantom Units**.

(a) *Restricted Units*. As of the date of this agreement, Executive shall receive an initial grant (the "***2010 Restricted Units***") of 12,500 restricted common units of Parent (the "***Restricted Units***") pursuant to the Vanguard Natural Resources, LLC Long-Term Incentive Plan (the "***LTIP***"). The terms and conditions of the 2010 Restricted Units are set forth in Appendix B hereto. Executive may receive additional restricted common units of Parent from time to time at the CEO's sole discretion during the Employment Period.

(b) *Phantom Units*. As of the date of this agreement, Executive shall receive an initial grant (the "***2010 Phantom Units***") of 12,500 phantom units ("***Phantom Units***") pursuant to the LTIP. The terms and conditions of the 2010 Phantom Units are set forth in Appendix C hereto. Executive shall receive an additional grant of 12,500 phantom common units of Parent on an annual basis in connection with each anniversary of the Effective Date during the Employment Period, the terms and conditions of such grant to be substantially the same as those described in Appendix C for the 2010 Phantom Units.

5. **Change of Control**.

(a) *Definition of Change of Control*. For purposes of this Agreement, a "***Change of Control***" shall have the same meaning as such term in the Company's LTIP. For the sake of convenience herein, as of the Effective Date, the LTIP states that a "Change of Control" means, and shall be deemed to have occurred upon one or more of the following events:

(i) Any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, as amended, other than an affiliate of Parent, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of fifty percent (50%) or more of the combined voting power of the equity interests in Parent;

(ii) The members of Parent approve, in one or a series of transactions, a plan of complete liquidation of Parent; or

(iii) The sale or other disposition by the Company of all or substantially all of its assets in one or more transactions to any person other than Parent or an affiliate of Parent.

Notwithstanding the foregoing, with respect to a payment that is subject to section 409A of the Code, a "Change of Control" shall mean a "change of control event" as defined in the regulations and guidance issued under section 409A of the Internal Revenue code of 1986, as amended (the " ***Code***").

(b) *Change of Control Payments*. Upon the occurrence of a Change of Control of the Company, Executive will be entitled to receive the sum of (i) an amount equaling two (2) times the sum of his Base Salary, Annual Bonus and the cash value of all Restricted Units which became vested in the calendar year prior to the Change of Control (the " ***Change of Control Payment***"), and (ii) any settlement that may be due to Executive pursuant to the acceleration of all outstanding Restricted Units and Phantom Units held by the Executive at the time of the Change of Control. *Notwithstanding the previous sentence, however*, the Change of Control Payment will be capped at a maximum of $2,000,000, even where the value of the individual components of the payment would have resulted in a greater payment to the Executive. Solely for purposes of the Change of Control Payment, the Executive's Base Salary and Annual Bonus shall be valued each as in effect at the time of the Change of Control, and the Restricted Units which vested in the year prior to the Change of Control shall be valued as of the grant date of such Restricted Units. The Restricted Units and Phantom Units, if any, will be settled in accordance with the terms and conditions of the LTIP and any individual award agreement (or in the event of the 2010 Restricted Units, in accordance with the terms and conditions contained in Appendix B hereto and the LTIP, or in the event of the 2010 Phantom Units, in accordance with the terms and conditions contained in Appendix C hereto and the LTIP).

(c) **Gross-Up for Certain Taxes Related to a Change of Control**.

(i) In the event that any payments to Executive pursuant to this Agreement or any payment received by Executive or paid by the Company on Executive's behalf is treated as contingent on a change in the ownership or effective control of the Parent or in the "ownership of a substantial portion of the assets" of Parent (but only if such payment or other benefit is in connection with Executive employment relationship with the Company) shall result in Executive becoming liable for the payment of any excise taxes pursuant to section 4999 of the Code (the " ***Section 4999 Excise Tax***"), Executive shall be entitled to an additional payment equal to the amount of any Section 4999 Excise Taxes payable by Executive pursuant to section 4999 of the Code as a result of such payments, plus all Federal, state and local taxes applicable solely to the Company's payment of such Section 4999 Excise Taxes, including any additional taxes due under section 4999 of the Code with respect to payments made pursuant to this provision (the " ***Section 4999 Gross-Up Payment***"). The Section 4999 Gross-Up Payment shall not include any Federal, state, or local taxes imposed upon the original payment that gave rise to such Section 4999 Excise Tax.

(ii) Calculations for the Section 4999 Gross-Up Payment shall assume the highest marginal rate applicable at the time of calculation.

(iii) The intent of this Section 5(c) is to provide that the Company shall pay Executive the Section 4999 Gross-Up Payment such that the net amount retained by Executive after deduction of the Section 4999 Excise Tax and any additional Federal, state or local taxes are imposed on the Section 4999 Excise Taxes or Section 4999 Gross-Up Payments, shall equal the aggregate total amount payable to the Executive pursuant to this Agreement. In the event that an excise tax is imposed by the Code or any Federal, state or local legislation following the Effective Date, in addition to or in place of the Section 4999 Excise Tax, the Company also intends to provide an appropriate gross-up payment which would provide Executive with the aggregate total amount of the intended payment before such excise tax (and any subsequent taxes imposed because of the Company's payment of such excise tax on Executive's behalf) was imposed.

(iv) If Executive determines that Executive is liable for the Section 4999 Excise Taxes with respect to a payment or other benefit pursuant to the Agreement, Executive must promptly so notify the Company in writing. Upon receipt of such notice from Executive, the Company must, within twenty (20) days thereafter, either (A) notify Executive, in writing, that the Company agrees with Executive's determination of the Section 4999 Excise Tax liability, in which case the Company shall become obligated to immediately pay to Executive the Section 4999 Gross-Up Payment, or (B) submit to Executive an opinion, prepared by counsel of the Company's choice which counsel is reasonably satisfactory to Executive, that Executive is not liable for the Excise Tax (the "***Tax Opinion***"). If the Tax Opinion is provided to Executive and Executive nevertheless chooses not to contest the assertion of the Section 4999 Excise Tax, the Company shall be relieved of its obligation to make the Section 4999 Gross-Up Payment specified hereunder. If Executive chooses to contest the assertion of the Section 4999 Excise Tax after receipt of the Tax Opinion, Executive may do so with counsel of Executive's choice that is reasonably satisfactory to the Company, with the reasonable legal fees and expenses of such contest to be paid by the Company, on a monthly basis, subject to the Company's receipt of proper documentation therefore. If the Section 4999 Excise Tax is successfully contested with the approval of counsel, then the Company shall pay to Executive the Section 4999 Gross-Up Payment upon the earlier of ten (10) days after (1) the entry of a final judgment, decree, or other order by a court of competent jurisdiction that Executive is liable for the Excise Tax, or (2) a mutual determination of Executive and the Company not to proceed further with the contest.

(v) If the Internal Revenue Service (the "***IRS***") notifies Executive in writing that the Section 4999 Excise Tax will or may be assessed against Executive, if the Company provides Executive with the Tax Opinion specified herein, and if Executive chooses to contest the assertion of the Section 4999 Excise Tax, then the Company shall obtain and deliver to Executive an irrevocable standby letter of credit (the " ***Letter of Credit***") issued by a bank acceptable to Executive and the Company in an amount equal to the amount of the Company's potential payment obligation herein including penalties and interest, computed as if the Section 4999 Excise Tax were paid to the IRS in the year the date the Letter of Credit was obtained. Immediately upon the earlier of (A) a determination letter (within the meaning of section 1313 of the Code) that Executive is not liable for the Section 4999 Excise Tax, or (B) the Company's payment to Executive of the full amount of its obligation herein, Executive shall mark the Letter of Credit "canceled" and return it to the Company. In lieu of such a Letter of Credit, the Company may choose to secure its obligations hereunder by establishing an appropriate escrow account with terms reasonably satisfactory to Executive, and by depositing therein the same amount as would be required for the Letter of Credit. The obligations contained in this Section 5(c) shall survive the termination or expiration of Executive employment with the Company and shall be fully enforceable thereafter.

(vi) In the event that any payment or any portion thereof made to the Executive or to any third-party on the Executive's behalf under this Section 5 is subsequently determined to not be imposed or not to be required of the Executive, then such payment shall be promptly returned to the Company.

6. **Termination of Employment**.

(a) *Termination without Cause or Resignation by Executive*. Unless otherwise specified in a separate provision of this Section 6, either Executive or VNR, by action of the CEO, may terminate this Agreement, and Executive's employment by VNR, for any reason after providing thirty (30) days written notice to the non-terminating party. If Executive terminates this Agreement pursuant to this provision, VNR will pay Executive on the Date of Termination (i) all accrued but unpaid Base Salary, (ii) a prorated amount of Executive's Base Salary for accrued but unused vacation days, and (iii) yet unpaid reimbursements for any reasonable and necessary business expenses incurred by Executive prior to the Date of Termination in connection with his duties hereunder (such amounts collectively, the "***Accrued Compensation and Reimbursements***"). Upon termination by VNR of this Agreement pursuant to this Section 6(a) other than a termination for Cause, within ten (10) business days after the Date of Termination, VNR shall pay (A) Accrued Compensation and Reimbursements, plus (B) a payment (a "***Severance Payment***") equal to the greater of Executive's Base Salary (at the rate in effect hereunder at the Date of Termination) for (1) thirty-six (36) months, or (2) the remaining duration of the Employment Period. Notwithstanding any other provision of this Agreement, the non-renewal of the Executive's employment pursuant to the terms of a Non-Renewal Notice under Section 1(a) of this Agreement shall not constitute a termination of this Agreement entitling the Executive to a Severance Payment under this Section 6(a).

(b) *Termination by Cause*. VNR, by action of the CEO may terminate this Agreement at any time for Cause. Upon termination by VNR for Cause, Executive shall only be entitled to Accrued Compensation and Reimbursements, which amount shall be paid within ten (10) business days after the Date of Termination. For purposes hereof, "***Cause***" means any of the following:

(i) Executive's commission of theft, embezzlement, any other act of dishonesty relating to his employment with VNR or any willful and material violation of any law, rules or regulation applicable to the Company, including, but not limited to, those laws, rules or regulations established by the Securities and Exchange Commission, or any self-regulatory organization having jurisdiction or authority over Executive or the Company; or

(ii) Executive's conviction of, or Executive's plea of guilty or *nolo contendere* to, any felony or of any other crime involving fraud, dishonesty or moral turpitude; or

(iii) A determination by the CEO that Executive has materially breached this Agreement (other than during any period of Disability, as defined below) where such breach is not remedied within ten (10) days after written demand by the CEO for substantial performance is actually received by Executive which specifically identifies the manner in which the CEO believes Executive has so breached; or

(iv) Executive's willful and continued failure to perform his reasonable and customary duties as the Senior Vice President of Operations which such failure is not remedied within ten (10) days after written demand by the CEO for substantial performance is actually received by Executive which specifically identifies the nature of such failure.

For purposes of the definition of Cause, no act or failure to act, on the part of Executive, shall be considered "willful" unless it is done, or omitted to be done, by Executive in bad faith or without reasonable belief that Executive's action or omission was in, or not opposed to, the best interests of the Company. Any act, or failure to act, based upon authority given by the CEO or based upon the advice of counsel for VNR shall be conclusively presumed to be done, or omitted to be done, by Executive in good faith and in the best interests of the Company. VNR, by action of the CEO, may terminate Executive's employment for Cause only after: (i) providing written notice to Executive, which identifies the Cause for Executive's termination (which notice must be given within ninety (90) days after the actual discovery of the act(s) or omission(s) constituting such Cause) and (ii) Executive has been given an opportunity, together with his counsel, to be heard by the CEO at a time and location reasonably designated by the CEO.

(c) *Termination with Good Reason*. Executive may terminate this Agreement for Good Reason, and thereby resign his employment, after providing thirty (30) days' written notice to the Company (which notice must be given within ninety (90) days after the occurrence of the act(s) or omission(s) constituting Good Reason). For purposes hereof, "***Good Reason***" means any of the following reasons:

(i) Executive is assigned duties and responsibilities materially inconsistent with those normally associated with his position, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by VNR promptly, but in no event later than the thirty (30) day period immediately following VNR's receipt of notice thereof given by Executive; or

(ii) A material reduction in Executive's Base Salary; or

(iii) Executive's removal from his position as Senior Vice President of Operations of the Company, other than for Cause or by death or Disability, during the Term of this Agreement, to a position that is not at least equivalent in authority and duties to Senior Vice President of Operations; or

(iv) Relocation of Executive's principal place of business to a location fifty (50) or more miles from its location as of the Effective Date without Executive's written consent; or

(v) A material breach by VNR of this Agreement, which materially adversely affects Executive, if the breach is not cured within twenty (20) days after Executive provides written notice to VNR which identifies in reasonable detail the nature of the breach; or

(vi) VNR's failure to make any material payment to Executive required to be made under the terms of this Agreement, if the breach is not cured within twenty (20) days after Executive provides written notice to the VNR which provides in reasonable detail the nature of the payment.

In the event Executive terminates this Agreement for Good Reason, within ten (10) business days after the Date of Termination VNR shall pay Executive (i) his Accrued Compensation and Reimbursements plus (ii) a Severance Payment.

(d) *Termination by Disability*. VNR, by action of the CEO, may terminate this Agreement at any time if Executive shall be deemed in the reasonable judgment of the CEO to have sustained a "***Disability***." Executive shall be deemed to have sustained a Disability if and only if he shall have been unable to substantially perform his duties as an employee of VNR as a result of sickness or injury, and shall have remained unable to perform any such duties for a period of more than 180 consecutive days in any twelve (12)-month period. Upon termination of this Agreement for Disability, VNR shall pay Executive (A) his Accrued Compensation and Reimbursements plus (B) a payment equal to Executive's Base Salary for twelve (12) months.

(e) *Termination by Death*. This Agreement will terminate automatically upon Executive's death. Upon termination of this Agreement because of Executive's death, VNR shall pay Executive's estate (i) Executive's Accrued Compensation and Reimbursements, plus (ii) a payment equal to Executive's Base Salary for twelve (12) months.

(f) *Date of Termination*. As used in this Agreement, "***Date of Termination***" means (i) if Executive's employment is terminated by his death, the date of his death; (ii) if Executive's employment is terminated as a result of a Disability or by VNR for Cause or without Cause, then the date specified in a notice delivered to Executive by VNR of such termination, (iii) if Executive's employment is terminated by Executive for Good Reason, then the date specified in the notice of such termination delivered to VNR by Executive, (iv) if Executive's employment terminates due to the giving of a Non-Renewal Notice, the last day of the Employment Period, and (v) if Executive's employment is terminated for any other reason, the date specified therefore in the notice of such termination.

7. **Employment**.

Upon termination of this Agreement, Executive's employment shall also terminate and cease.

8. **Mitigation**.

Upon termination of this Agreement for any reason, amounts to be paid per the express terms of this Agreement shall not be reduced whether or not Executive obtains other employment.

9. **Release**.

Notwithstanding any other provision in this Agreement to the contrary, as a condition precedent to receiving the Severance Payment set forth in this Agreement in connection with any applicable termination scenario, Executive agrees to execute (and not revoke) a customary severance and release agreement, including a waiver of all claims, reasonably acceptable to the Company (the " ***Release***"), within the forty-five (45) day period immediately following the Date of Termination. All revocation rights and timing restrictions shall be set forth in such Release. If Executive fails to execute and deliver the Release, or revokes the Release, Executive agrees that he shall not be entitled to receive or retain the Severance Payment. For purposes of this Agreement, the Release shall be considered to have been executed by Executive if it is signed by his legal representative in the case of legal incompetence or on behalf of Executive's estate in the case of his death.

10. **Nondisclosure**.

(a) Executive shall, immediately upon executing this Agreement, receive access to some or all of the Company's various trade secrets and confidential or proprietary information, including information he has not received before, consisting of, but not limited to, information relating to (i) business operations and methods, (ii) existing and proposed investments and investment strategies, (iii) financial performance, (iv) compensation arrangements and amounts (whether relating to the Company or to any of its employees), (v) contractual relationships, (vi) business partners and relationships, and (vii) marketing strategies (all of the forgoing, "***Confidential Information***"). Confidential Information shall not include: (A) information that Executive may furnish to third parties regarding his obligations under this Section 10 and under Section 11 or (B) information that (1) is general knowledge of Executive or information that becomes generally available to the public by means other than Executive's breach of this Section 10 (for example, not as a result of Executive's unauthorized release of marketing materials), (2) is in Executive's possession, or becomes available to Executive, on a non-confidential basis, from a source other than the Company or (3) Executive is required by law, regulation, court order or discovery demand to disclose; provided, however, that in the case of clause (3), Executive gives the Company, to the extent permitted by law, reasonable notice prior to the disclosure of the Confidential Information and the reasons and circumstances surrounding such disclosure to provide the Company an opportunity to seek a protective order or other appropriate request for confidential treatment of the applicable Confidential Information.

(b) Executive agrees that all Confidential Information, whether prepared by Executive or otherwise coming into his possession, shall remain the exclusive property of the Company during Executive's employment with the Company. Executive further agrees that Executive shall not, except for the benefit of the Company pursuant to the exercise of his duties in accordance with this Agreement or with the prior written consent of the Company, use or disclose to any third party any of the Confidential Information described herein, directly or indirectly, either during Executive's employment with the Company or at any time following the termination of Executive's employment with the Company.

(c) Upon termination of this Agreement, Executive agrees that all Confidential Information and other files, documents, materials, records, notebooks, customer lists, business proposals, contracts, agreements and other repositories containing information concerning the Company or the business of the Company (including all copies thereof) in Executive's possession, custody or control, whether prepared by Executive or others, shall remain with or be returned to the Company as soon as practicable after the Date of Termination.

11. **Non-Competition and Non-solicitation**.

(a) As part of the consideration for the compensation and benefits to be paid to Executive hereunder, to protect Confidential Information of the Company and its customers and clients that have been and will be entrusted to Executive, the business goodwill of the Company and its subsidiaries that will be developed in and through Executive and the business opportunities that will be disclosed or entrusted to Executive by the Company and its subsidiaries, and as an additional incentive for the Company to enter into this Agreement, if termination is a result of Executive's voluntary termination without Good Reason under Section 6(a), or by the Company for Cause under Section 6(b), from the date hereof through the one (1) year anniversary of the Date of Termination (the "***Restricted Period***"), Executive will not (other than for the benefit of the Company pursuant to this Agreement), directly or indirectly:

(i) engage in, or carry on or assist, individually or as an officer, director, employee, consultant or contractor or in any other capacity whatsoever (in any such capacity, an "***Investor***"), any (A) any publicly traded partnership or limited liability company directly competitive with the business in which the Company is engaged from time to time (" ***Competing Business***") or (B) Business Enterprise (as defined below) that is otherwise directly competitive with the Company;

(ii) perform for any corporation, partnership, limited liability company, sole proprietorship, joint venture or other business association or entity (a "***Business Enterprise***") engaged in any Competing Business any duty Executive has performed for the Company that involved Executive's access to, or knowledge or application of, Confidential Information;

(iii) induce or attempt to induce any customer, supplier, licensee or other business relation of the Company to cease doing business with the Company or in any way interfere with the relationship between any such customer, supplier, licensee or business relation and the Company;

(iv) induce or attempt to induce any customer, supplier, licensee or other business relation of the Company with whom Executive had direct business contact in dealings during the Employment Period in the course of his employment with the Company to cease doing business with the Company or in any way interfere with the relationship between any such customer, supplier, licensee or business relation and the Company; or

(v) solicit with the purpose of hiring or hire any person who is or, within 180 days after such person ceased to be an employee of the Company, was an employee of the Company.

(b) Notwithstanding the foregoing restrictions of this Section 11, nothing in this Section 11 shall prohibit (i) any investment by Executive, directly or indirectly, in securities which are issued by a Business Enterprise involved in or conducting a Competing Business, provided that Executive, directly or indirectly, does not own more than five percent (5%) of the outstanding equity or voting securities of such Business Enterprise or (ii) Executive, directly or indirectly, from owning any interest in any Business Enterprise which conducts a Competing Business if such interest in such Business Enterprise is owned as of the date of this Agreement and Executive does not have the right, in the case of (i) or (ii), through the ownership of a voting interest or otherwise, to direct the activities of or associated with the business of such Business Enterprise.

(c) Executive acknowledges that each of the covenants of Section 11(a) are in addition to, and shall not be construed as a limitation upon, any other covenant provided in Section 11(a). Executive agrees that the geographic boundaries, scope of prohibited activities, and time duration of each of the covenants set forth in Section 11(a) are reasonable in nature and are no broader than are necessary to maintain the confidentiality and the goodwill of the Company's proprietary and Confidential Information, plans and services and to protect the other legitimate business interests of the Company, including without limitation the goodwill developed by Executive with Company's customers, suppliers, licensees and business relations.

(d) If, during any portion of the Restricted Period, Executive is not in compliance with the terms of Section 11(a), the Company shall be entitled to, among other remedies, compliance by Executive with the terms of Section 11(a) for an additional period of time (*i.e.*, in addition to the Restricted Period) that shall equal the period(s) over which such noncompliance occurred.

(e) The parties hereto intend that the covenants contained in Section 11(a) be construed as a series of separate covenants, one for each defined province in each geographic area in which Executive on behalf of the Company conducts business. Except for geographic coverage, each such separate covenant shall be deemed identical in terms to the applicable covenant contained in Section 11(a). Furthermore, each of the covenants in Section 10(a) shall be deemed a separate and independent covenant, each being enforceable irrespective of the enforceability (with or without reformation) of the other covenants contained in Section 11(a).

12. **Survival of Covenants**.

Sections 10 and 11 shall survive the expiration or termination of this Agreement for any reason, except that the restrictions of Section 11 shall not apply in the event Executive's employment is terminated as a result of a Change of Control other than in connection with a Permitted Transfer (as such term is defined in the limited liability agreement for Parent (the "***LLC Agreement***")). Executive further agrees to notify all future persons, funds or businesses, with which he becomes affiliated with or employed by during the Restricted Period, of the restrictions set forth in Sections 10 and 11, prior to the commencement of any such affiliation or employment.

13. **Notices**.

All notices and other communications required or permitted to be given hereunder shall be in writing and shall be deemed to have been duly given if delivered personally, mailed by certified mail (return receipt requested) or sent by overnight delivery service to the parties at the following addresses or at such other addresses as shall be specified by the parties by like notice, in order of preference of the recipient:

To VNR:
Chief Executive Officer
5847 San Felipe, Suite 3000
Houston, Texas 77057
Facsimile: (832) 327-2260

To the Executive:
Britt Pence
5847 San Felipe, Suite 3000
Houston, Texas 77057

Notice so given shall, in the case of mail, be deemed to be given and received on the fifth calendar day after posting, and in the case overnight delivery service, on the date of actual delivery.

14. **Severability and Reformation**.

If any one or more of the terms, provisions, covenants or restrictions of this Agreement shall be determined by a court of competent jurisdiction to be invalid, void or unenforceable, the remainder of the terms, provisions, covenants and restrictions shall remain in full force and effect, and the invalid, void or unenforceable provisions shall be deemed severable. Moreover, if any one or more of the provisions contained in this Agreement shall for any reason be held to be excessively broad as to duration, geographical scope, activity or subject, it shall be reformed by limiting and reducing it to the minimum extent necessary, so as to be enforceable to the extent compatible with the applicable law as it shall then appear.

15. **Assignment**.

This Agreement shall be binding upon and inure to the benefit of the heirs and legal representatives of Executive and the permitted assigns and successors of VNR, but neither this Agreement nor any rights or obligations hereunder shall be assignable or otherwise subject to hypothecation by Executive (except by will or by operation of the laws of intestate succession) or by VNR, except that VNR may assign this Agreement to any successor (whether by merger, purchase or otherwise) to all or substantially all of the stock assets or businesses of VNR, if such successor expressly agrees to assume the obligations of VNR hereunder.

16. **Amendment**.

This Agreement may be amended only by writing signed by both the Executive and by a duly authorized representative of VNR (other than Executive).

17. **Assistance in Litigation**.

Executive shall reasonably cooperate with the Company in the defense or prosecution of any claims or actions now in existence or that may be brought in the future against or on behalf of the Company that relate to events or occurrences that transpired while Executive was employed by the Company. Executive's cooperation in connection with such claims or actions shall include, but not be limited to, being available to meet with counsel to prepare for discovery or trial and to act as a witness on behalf of the Company at mutually convenient times. Executive also shall cooperate fully with the Company in connection with any investigation or review by any Federal, state, or local regulatory authority as any such investigation or review relates, to events or occurrences that transpired while Executive was employed by the Company. The Company will pay Executive an agreed upon reasonably hourly rate for Executive's cooperation pursuant to this Section 17.

18. **Beneficiaries; References**.

Executive shall be entitled to select (and change, to the extent permitted under any applicable law) a beneficiary or beneficiaries to receive any compensation or benefit payable hereunder following Executive's death, and may change such election, in either case by giving the Company written notice thereof. In the event of Executive's death or a judicial determination of his incompetence, reference in this Agreement to Executive shall be deemed, where appropriate, to refer to his beneficiary, estate or other legal representative. Any reference to the masculine gender in this Agreement shall include, where appropriate, the feminine.

19. **Use of Name, Likeness and Biography**.

The Company shall have the right (but not the obligation) to use, publish and broadcast, and to authorize others to do so, the name, approved likeness and approved biographical material of Executive to advertise, publicize and promote the business of the Company and its affiliates, but not for the purposes of direct endorsement without Executive's consent. This right shall terminate upon the termination of this Agreement. An "approved likeness" and "approved biographical material" shall be, respectively, any photograph or other depiction of Executive, or any biographical information or life story concerning the professional career of Executive.

20. **Governing Law**.

THIS AGREEMENT SHALL BE CONSTRUED, INTERPRETED AND GOVERNED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS WITHOUT REFERENCE TO RULES RELATING TO CONFLICTS OF LAW.

21. **Entire Agreement**.

This Agreement contains the entire understanding between the parties hereto with respect to the subject matter hereof and supersede in all respects any prior or other agreement or understanding, written or oral, between the Company or any affiliate of the Company and Executive with respect to such subject matter.

22. **Withholding**.

The Company shall be entitled to withhold from payment to the Executive of any amount of withholding required by law.

23. **Counterparts**.

This Agreement may be executed in two or more counterparts, each of which will be deemed an original.

24. **Remedies**.

The parties recognize and affirm that in the event of a breach of Sections 10 or 11 of this Agreement, money damages would be inadequate and VNR would not have an adequate remedy at law. Accordingly, the parties agree that in the event of a breach or a threatened breach of Sections 10 or 11, VNR may, in addition and supplementary to other rights and remedies existing in its favor, apply to any court of law or equity of competent jurisdiction for specific performance and/or injunctive or other relief in order to enforce or prevent any violations of the provisions hereof (without posting a bond or other security). In addition, Executive agrees that in the event a court of competent jurisdiction or an arbitrator finds that Executive violated Section 10 or 11, the time periods set forth in those Sections shall be tolled until such breach or violation has been cured. Executive further agrees that VNR shall have the right to offset the amount of any damages resulting from a breach by Executive of Section 10 or 11 against any payments due Executive under this Agreement. The parties agree that if one of the parties is found to have breached this Agreement by a court of competent jurisdiction or arbitrator, the breaching party will be required to pay the non-breaching party’s attorneys’ fees reasonably incurred in prosecuting the non-breaching party’s claim of breach.

25. **Non-Waiver**.

The failure by either party to insist upon the performance of any one or more terms, covenants or conditions of this Agreement shall not be construed as a waiver or relinquishment of any right granted hereunder or of any future performance of any such term, covenant or condition, and the obligation of either party with respect hereto shall continue in full force and effect, unless such waiver shall be in writing signed by VNR (other than Executive) and Executive.

26. **Announcement**.

The Company shall have the right to make public announcements concerning the execution of this Agreement and the terms contained herein, at the Company's discretion.

27. **Construction**.

The headings and captions of this Agreement are provided for convenience only and are intended to have no effect in construing or interpreting this Agreement. The language in all parts of this Agreement shall be in all cases construed in accordance to its fair meaning and not strictly for or against the Company or Executive.

28. **Right to Insure**.

The Company shall have the right to secure, in its own name or otherwise, and at its own expense, life, health, accident or other insurance covering Executive, and Executive shall have no right, title or interest in and to such insurance. Executive shall assist the Company in procuring such insurance by submitting to examinations and by signing such applications and other instruments as may be required by the insurance carriers to which application is made for any such insurance.

29. **No Inconsistent Obligations**.

Executive represents and warrants that to his knowledge he has no obligations, legal, in contract, or otherwise, inconsistent with the terms of this Agreement or with his undertaking employment with the Company to perform the duties described herein. Executive will not disclose to the Company, or use, or induce the Company to use, any confidential, proprietary, or trade secret information of others. Executive represents and warrants that to his knowledge he has returned all property and confidential information belonging to all prior employers, if he is obligated to do so.

30. **Binding Agreement**.

This Agreement shall inure to the benefit of and be binding upon Executive, his heirs and personal representatives, and the Company, its successors and assigns.

31. **Voluntary Agreement**.

Each party to this Agreement has read and fully understands the terms and provisions hereof, has had an opportunity to review this Agreement with legal counsel, has executed this Agreement based upon such party's own judgment and advice of counsel (if any), and knowingly, voluntarily, and without duress, agrees to all of the terms set forth in this Agreement. The parties have participated jointly in the negotiation and drafting of this Agreement. If an ambiguity or question of intent or interpretation arises, this Agreement will be construed as if drafted jointly by the parties and no presumption or burden of proof will arise favoring or disfavoring any party because of authorship of any provision of this Agreement. Except as expressly set forth in this Agreement, neither the parties nor their affiliates, advisors and/or their attorneys have made any representation or warranty, express or implied, at law or in equity with respect of the subject matter contained herein. Without limiting the generality of the previous sentence, the Companies, their affiliates, advisors, and/or attorneys have made no representation or warranty to Executive concerning the state or Federal tax consequences to Executive regarding the transactions contemplated by this Agreement.

[THE REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK; SIGNATURE PAGE IMMEDIATELY FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have executed this Amended Employment Agreement between VNR and Britt Pence as of the day and year first above written.

“**EXECUTIVE**”

/s/ Britt Pence

VNR HOLDINGS, LLC

“**COMPANY**”

By:
/s/ Scott W. Smith
Its:

VANGUARD NATURAL RESOURCES, LLC

By:
/s/ Scott W. Smith
Its: Chief Executive Officer and President

APPENDIX A

Annual Bonus

1. Executive is eligible to receive an Annual Bonus based upon the CEO's annual bonus system described below. Executive is eligible to receive a "Maximum" Annual Bonus equal to two (2) times Executive's Base Salary. The Annual Bonus for each calendar year during the Employment Period will be based on the following components and percentages:

   (a) Absolute Target Distribution Growth ("***ATDG***") (33 1/3%)

   (b) Relative Unit Performance versus Peer Group ("***RUP***") (33 1/3%)

   (c) CEO Discretion ("***Discretion***") (33 1/3%)

2. ATDG for each calendar year will be a function of VNR's dividend yield on the last day of each applicable calendar year, with the target growth for each calendar year of 5%. ATDG for the 2010 calendar year will be measured based on a theoretical year end distribution rate of $2.05 (actual year end distribution rate is acknowledged to be $2.00) as follows:

	> 75%	**> 100%**	**> 125%**	**> 150%**	**> 175%**	**> 200%**
ATDG	$2.13	$2.15	$2.18	$2.20	$2.23	$2.26

   A new table for each subsequent year during the Employment Period will be generated based on a 5% growth rate on the December 31 distribution then in effect.

3. RUP will be calculated by comparing the rolling average three (3) year common unit price percentage increase for VNR's Peer Group to VNR's rolling average three (3) year common unit price percentage increase. VNR's "***Peer Group***" shall consist of the following entities:

   (a) Linn Energy, LLC (LINE)

   (b) Legacy Reserves, LP (LGCY)

   (c) EV Energy Partners LP (EVEP)

   (d) Encore Energy Partners LP (ENP)

   (e) Pioneer Southwest Energy Partners, L.P. (PSE)

   In the event the CEO determines that any of the Peer Group entities is no longer an appropriate "peer" for the Company, or such entity is no longer a viable business, at the time an RUP analysis is necessary for an Annual Bonus calculation, the CEO may make such necessary additions or adjustments to the Peer Group as it deems appropriate.

4. The Discretion component of each Annual Bonus is determined at the sole discretion of the CEO, and shall be based upon such targets, performance measures relative to the Company and/or the Executive, time frames, and any other item the CEO has determined appropriate for each Annual Bonus.

5. Targets for ATDG, RUP and Discretion shall be set as follows:

	> 75%	**> 100%**	**> 125%**	**> 150%**	**> 175%**	**> 200%**
ATDG	50%	100%	125%	150%	175%	200%
RUP	0	75%	100%	125%	150%	200%
Discretion	0 to 200%	0 to 200%	0 to 200%	0 to 200%	0 to 200%	0 to 200%

6. Each of the ATDG and the RUP portion of an Annual Bonus shall be calculated by multiplying (a) Base Salary, by (b) weight, by (c) bonus in percentage of Base Salary. Payment of the Annual Bonus shall be made in a lump sum cash payment to the Executive on April 1st of each calendar year that immediately follows the calendar year to which the Annual Bonus relates, so long as Executive was continuously employed with the Company during the full applicable calendar year to which the Annual Bonus relates.

APPENDIX B

[Restricted Unit Agreement]

APPENDIX C

[Phantom Unit Agreement]

Exhibit 10.2

VANGUARD NATURAL RESOURCES, LLC

LONG-TERM INCENTIVE PLAN

RESTRICTED UNIT AWARD AGREEMENT

To: Britt Pence Date of Grant: June 13, 2010 Number of Units: 12,500

THIS RESTRICTED UNIT AWARD AGREEMENT (the "***Agreement***") is made as of June 13, 2010 between Vanguard Natural Resources, LLC (the "***Company***"), and Britt Pence (the "***Executive***") pursuant to the terms and conditions of the Company's Long-Term Incentive Plan (the " ***Plan***") and that certain Employment Agreement between Executive and the Company effective as of May 15, 2010 (the " ***Employment Agreement***"). A copy of the Plan is being furnished to the Executive concurrently with the execution of this Agreement which shall be deemed a part of this Agreement as if fully set forth herein. By the execution of this Agreement, the Executive acknowledges receipt of a copy of the Plan. Unless the context otherwise requires, all terms defined in the Plan shall have the same meaning when used herein.

WHEREAS, the Board of Directors of the Company (the " ***Board***") has adopted the Plan to encourage and enable certain employees and consultants of the Company to acquire Awards the value of which is tied to the performance of the common unit (a " ***Unit***") of the Company, thus providing them with a more direct concern in the welfare of the Company and assuring a closer identification of their interests with those of the Company; and

WHEREAS, the Executive is one of such eligible employees.

NOW THEREFORE, the parties agree as follows:

1. Restricted Unit Award. The Company hereby grants to the Executive (the "***Award***"), effective as of June 13, 2010 (the "***Date of Grant***"), an award of 12,500 restricted Units, subject to the terms and conditions set forth in the Plan, which is incorporated herein by reference, and in this Agreement, including, without limitation, those restrictions described in Section 2 (the " ***Restricted Units***"). The Award is specifically made subject to execution by the Executive of this Agreement.

2. Forfeiture Restrictions. The Restricted Units are restricted in that they may be forfeited to the Company and in that they may not, except as otherwise provided in this Agreement or in the Plan, be transferred or otherwise disposed of by the Executive until such restrictions are removed or expire as described in Section 3 of this Agreement. The Company shall issue in the Executive's name the Restricted Units and shall retain the Restricted Units until the restrictions on such Restricted Units expire or until the Restricted Units are forfeited as described in Section 3 of this Agreement. The Executive agrees that the Company will hold the Restricted Units pursuant to the terms of this Agreement until such time as the Restricted Units are either delivered to the Executive or forfeited pursuant to this Agreement.

3. Vesting and Forfeiture of Restricted Units. Subject to the terms and conditions of this Agreement, the restrictions described in Section 2 shall lapse and the Restricted Units shall become vested and nonforfeitable, provided the Executive has continuously provided services to the Company, without interruption, from the Date of Grant through each applicable vesting date (each, a " ***Vesting Date***"), in accordance with the following schedule:

Vesting Date	Percentage of Restricted Units Vested
May 15, 2011	33 1/3%
May 15, 2012	66 2/3%
May 15, 2013	100%

Restricted Units that may be settled pursuant to the schedule above are " ***Vested Units***." Restricted Units that may not be settled pursuant to the schedule above are "***Unvested Units***."

(a) Termination of Employment for Other Than Cause, or by Executive for Good Reason . In the event the Company terminates the Executive's employment for any reason other than for Cause, or Executive voluntarily resigns for Good Reason (both terms as defined in the Employment Agreement, as the same may be amended from time to time), all Unvested Units shall immediately become Vested Units and thereafter this Award may be settled pursuant to Section 4 below with respect to the number of Vested Units held by the Executive.

(b) Termination Employment for Cause. In the event the Executive's employment is terminated for Cause all Restricted Units (both Vested Units and Unvested Units) that have not been settled as of the date of such removal shall be forfeited.

(c) Termination by Reason of Death or Disability. For purposes of this Agreement, termination by reason of the Executive's death or Disability (as defined in the Employment Agreement, as the same may be amended from time to time) shall be deemed to be a termination pursuant to Section 3(a) above.

(d) Change in Control. Upon the occurrence of a Change in Control, all Unvested Units shall immediately become Vested Units held by the Executive.

4. Settlement of Restricted Units. Subject to Section 10 below, the Executive shall be entitled to have the restrictions removed from his Unit certificate(s) as to the number of Restricted Units that become Vested Units on any given Vesting Date or any date of accelerated vesting pursuant to Sections 3(a), 3(c) or 3(d) above, so that the Executive then holds an unrestricted Unit.

5. Transferability and Assignment. This Agreement and the Restricted Units granted hereunder will not be transferable by the Executive other than by will or the laws of descent and distribution. Any attempt by the Executive to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

6. Recapitalization or Reorganization.

(a) Existence of Plan and Award. The existence of the Plan and the Award shall not affect in any way the right or power of the Board or the Company to make or authorize any adjustment, recapitalization, reorganization or other change in the Company's capital structure or its business, any merger or consolidation of the Company, any issue of debt or equity securities ahead of or affecting Units or the rights thereof, the dissolution or liquidation of the Company or any sale, lease, exchange or other disposition of all or any part of its assets or business or any other corporate act or proceeding.

(b) Subdivision or Consolidation of Units. The terms of this Award shall be subject to adjustment from time to time, in accordance with the following provisions:

(i) If at any time, or from time to time, the Company shall subdivide as a whole (by reclassification, by a unit split, by the issuance of a dividend on Units payable in Units, or otherwise) the number of shares of Units then outstanding into a greater number of shares of Units, then the number of shares of Restricted Units specified in Section 1 above shall be increased proportionately.

(ii) If at any time, or from time to time, the Company shall consolidate as a whole (by reclassification, reverse unit split, or otherwise) the number of shares of Units then outstanding into a lesser number of shares of Units, the number of shares of Restricted Units specified in Section 1 above shall be decreased proportionately.

(iii) Whenever the number of shares of Units subject to this Award are required to be adjusted as provided in this Section 6(b), the Company shall promptly prepare and deliver to the Executive a notice setting forth, in reasonable detail, the event requiring adjustment, the amount of the adjustment, the method by which such adjustment was calculated, and the change in the number of shares of Restricted Units specified in Section 1 above after giving effect to the adjustments. The Company shall promptly give the Executive such a notice.

(iv) Adjustments under Sections 6(b)(i) and (ii) shall be made by the Company, and its determination as to what adjustments shall be made and the extent thereof shall be final, binding, and conclusive.

7. No Multiple Payments. Settlement of the Restricted Units shall not occur under more than one provision of this Agreement.

8. Information Confidential. As partial consideration for the granting of the Restricted Units hereunder, the Executive hereby agrees with the Company that the Executive will keep confidential all information and knowledge that the Executive has relating to the terms and conditions of this Agreement; provided, however, that such information may be disclosed as required by law and may be given in confidence to the Executive's spouse, tax and financial advisors, or to a financial institution to the extent that such information is necessary to secure a loan. In the event any breach of this promise comes to the attention of the Company, it shall take into consideration that breach in determining whether to recommend the grant of any future similar award to the Executive, as a factor militating against the advisability of granting any such future award to the Executive.

9. No Right to Continued Employment. This Agreement shall not be construed to confer upon the Executive any right to continue as an employee of the Company. Any question as to whether there has been a termination of such employment, and the cause of such termination, shall be determined by the Chief Executive Officer or the Board and its determination shall be final and binding.

10. Payment of Taxes. The Company may from time to time, in its discretion, require the Executive to pay the Company the amount that the Company deems necessary to satisfy the Company's current or future obligation to withhold federal, state or local income or other taxes incurred by the Executive as a result of the vesting or settlement of the Award. With respect to any required tax withholding, (a) the Company may withhold from any Unit settlement the number of Units necessary to satisfy the Company's obligation to withhold taxes, (b) with the Company's consent, the Executive may deliver sufficient cash to the Company to satisfy its tax withholding obligations, or (c) the withholding obligations may be met by any such other arrangement that is acceptable to the Company and the Executive. In the event that the Company subsequently determines that the amount withheld as payment of any tax withholding obligation is insufficient to discharge that tax withholding obligation, then the Executive shall pay to the Company, immediately upon the Company's request, the amount of that deficiency.

11. Administration. This Agreement shall at all times be subject to the terms and conditions of the Plan. The Company shall have sole and complete discretion with respect to all matters reserved to it by the Plan and all decisions of the Company with respect thereto and this Agreement shall be final and binding upon the Executive and the Company. In the event of any conflict between the terms and conditions of this Agreement and the Plan, the provisions of the Plan shall control.

12. Unfunded Arrangement. This Agreement and the Plan shall not give a Executive any security or other interest in any assets of the Company; rather the Executive's right to the Award is that of a general unsecured creditor of the Company.

13. No Liability for Good Faith Determinations. The Company and the members of the Board shall not be liable for any act, omission or determination taken or made in good faith with respect to this Agreement or the Restricted Units granted hereunder.

14. No Guarantee of Interests. The Company and the members of the Board do not guarantee the Units from loss or depreciation.

15. Company Records. Records of the Company regarding the Executive's period of service, termination of service and the reason therefor, leaves of absence, and other matters shall be conclusive for all purposes hereunder, unless determined by the Company to be incorrect.

16. Company Action. Any action required of the Company shall be by resolution of its Board or by a person authorized to act by resolution of the Board.

17. Severability. If any provision of this Agreement is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions hereof, but such provision shall be fully severable and this Agreement shall be construed and enforced as if the illegal or invalid provision had never been included herein.

18. Notices. All notices required or permitted under this Agreement must be in writing and personally delivered or sent by mail and shall be deemed to be delivered on the date on which it is actually received by the person to whom it is properly addressed. A notice shall be effective when actually received by the Company in writing and in conformance with this Agreement and the Plan.

19. Waiver of Notice. Any person entitled to notice hereunder may waive such notice.

20. Successors. This Agreement shall be binding upon the Executive, the Executive's legal representatives, heirs, legatees and distributees, and upon the Company, its successors and assigns.

21. Headings. The titles and headings of Sections are included for convenience of reference only and are not to be considered in construction of the provisions hereof.

22. Governing Law. All questions arising with respect to the provisions of this Agreement shall be determined by application of the laws of the State of Delaware without regard to choice of law provisions thereunder, except to the extent Delaware law is preempted by federal law.

23. Word Usage. Words used in the masculine shall apply to the feminine where applicable, and wherever the context of this Agreement dictates, the plural shall be read as the singular and the singular as the plural.

24. Amendment. This Agreement may be amended by the Company; provided, however, that no amendment may decrease Executive's rights inherent in this Agreement prior to such amendment without Executive's express written consent. Notwithstanding the provisions of this Section 24, this Agreement may be amended by the Company, without the consent of the Executive, to the extent necessary to comply with applicable laws and regulations and to conform the provisions of this Agreement to any changes thereto or to settle the Award pursuant to all applicable provisions of the Plan.

25. Nonqualified Deferred Compensation Rules. In the event this Award fails to meet the limitations, requirements or exemptions of or from Section 409A of the Internal Revenue Code of 1986, as amended (the "***Code***"), or the laws, rules, and regulations promulgated in connection with Section 409A of the Code, then this Award shall be modified by the Company, in its sole discretion, to the limited extent necessary to satisfy such nonqualified deferred compensation rules.

IN WITNESS WHEREOF, the Company has caused this Agreement to be executed by its duly authorized officer effective as of June 13, 2010.

VANGUARD NATURAL RESOURCES, LLC

By: /s/ Scott W. Smith

Name: Scott W. Smith

Title: Chief Executive Officer and President

EXECUTIVE

/s/ Britt Pence
Britt Pence

Exhibit 10.3

VANGUARD NATURAL RESOURCES, LLC

LONG-TERM INCENTIVE PLAN

PHANTOM UNIT AWARD AGREEMENT

To: Britt Pence Date of Grant: June 18, 2010 Number of Units: 12,500

THIS PHANTOM UNIT AWARD AGREEMENT (the "***Agreement***") is made as of June 18, 2010 between Vanguard Natural Resources, LLC (the "***Company***"), and Britt Pence (the "***Executive***") pursuant to the terms and conditions of the Company's Long-Term Incentive Plan (the "***Plan***") and that certain Employment Agreement between Executive and the Company effective as of May 15, 2010 (the "***Employment Agreement***"). A copy of the Plan is being furnished to the Executive concurrently with the execution of this Agreement which shall be deemed a part of this Agreement as if fully set forth herein. By the execution of this Agreement, the Executive acknowledges receipt of a copy of the Plan. Unless the context otherwise requires, all terms defined in the Plan shall have the same meaning when used herein.

WHEREAS, the Board of Directors of the Company (the "***Board***") has adopted the Plan to encourage and enable certain employees and consultants of the Company to acquire Awards the value of which is tied to the performance of the common unit (a "***Unit***") of the Company, thus providing them with a more direct concern in the welfare of the Company and assuring a closer identification of their interests with those of the Company; and

WHEREAS, the Executive is one of such eligible employees.

NOW THEREFORE, the parties agree as follows:

1. Phantom Unit Award. The Company hereby grants to the Executive (the "***Award***"), effective as of June 18, 2010 (the "***Date of Grant***"), in accordance with the terms and conditions set forth herein and in the Plan, the right to receive 12,500 phantom units (the "***Phantom Units***"). The Award is specifically made subject to execution by the Executive of this Agreement.

2. Dividend Equivalents. The Executive will be entitled to receive, from the Date of Grant of this Award, an additional right to distribution equivalents, or DERs, which shall be equal in value to the value of any distributions made by the Company with respect to the number of shares of Units specified in Section 1 above on and after the Date of Grant. The Executive may choose, in his discretion, whether to (a) directly receive the DERs in the form of a cash payment at the time that all other members of the Company receive distributions in relation to Units, or (b) receive a credit to a bookkeeping account (without interest) for any DER received from the Date of Grant until the payment of the underlying Phantom Units. The Executive will notify the Company of his choice by filing an election form with the Secretary of the Company, such form to be provided by the Company in accordance with the rules and procedures adopted by the Company. In the event that Executive chooses to defer his DERs pursuant to this Section 2(b), however, the amount of the aggregate number of DERs due to Executive upon the settlement date will be multiplied by 1.25 (the "***Deferral Multiplier***") prior to payment. For example, if the aggregate amount of DERs that would have been paid to Executive from the Date of Grant until the payment of the underlying Phantom Units absent the Executive's deferral pursuant to this Section 2(b) equals $20,000, the cash payment due to the Executive upon settlement of the DERs shall be $25,000 ($20,000 x 1.25).

3. Vesting of Phantom Units. Subject to the earlier expiration of this Award as herein provided, this Award may be settled in accordance with the provisions of this Agreement in accordance with the following schedule:

Date of Vesting	Percentage of Rights That Become Vested
May 15, 2013	100%

Phantom Units that may be settled pursuant to the schedule above are "Vested Units." Phantom Units that may not be settled pursuant to the schedule above are "Unvested Units."

(a) Termination of Employment for Cause. In the event the Executive's employment is terminated for Cause (as defined in the Employment Agreement, as the same may be amended from time to time) all Phantom Units (both Vested Units and Unvested Units) that have not been settled as of the date of such removal shall be forfeited.

(b) Termination of Employment without Cause, or by Executive for Good Reason Prior to Vesting. In the event the Company terminates the Executive's employment for any reason other than for Cause, or the Executive voluntarily resigns for Good Reason (both terms as defined in the Employment Agreement, as the same may be amended from time to time), all Unvested Units shall immediately become Vested Units upon such a termination of employment.

(c) Termination of Employment by Reason of Death or Disability. For purposes of this Agreement, termination by reason of the Executive's death or Disability (as defined in the Employment Agreement, as the same may be amended from time to time) shall be deemed to be a termination pursuant to Section 3(b) above.

(d) Change in Control. Upon the occurrence of a Change in Control, all Unvested Units shall immediately become Vested Units.

4. Settlement of Phantom Units and DERs.

(a) Settlement. The Vested Units shall be settled by the Company within the earliest to occur of the following periods: (i) except in the event that Executive is terminated for Cause as noted in Section 3 above, within 60 days following the date the Executive incurs a "separation from service" (within the meaning of Treasury Regulation § 1.409A-1(h)(1)) from the Company, or (ii) within 60 days following a Change in Control. The Vested Units will be settled through the delivery of a number of Units equal to the number of Phantom Units granted to Executive pursuant to Section 1.

(b) Settlement of Deferred DERs. All DERs deferred pursuant to Section 2(b) and credited to the Executive from the Date of Grant through the date of the settlement of the Vested Units shall also be settled upon the date of settlement for the Vested Units pursuant to Section 4(a) above. All DERs, after taking into account the Deferral Multiplier, shall be settled in the form of a lump-sum cash payment made to the Executive upon the applicable settlement date.

(c) Procedures. Settlement of Phantom Units shall be subject to and pursuant to rules and procedures established by the Company in its sole discretion.

5. Transferability and Assignment. This Agreement and the Phantom Units granted hereunder will not be transferable by the Executive other than by will or the laws of descent and distribution. Any attempt by the Executive to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

6. Recapitalization or Reorganization.

(a) Existence of Plan and Award. The existence of the Plan and the Award shall not affect in any way the right or power of the Board or the Company to make or authorize any adjustment, recapitalization, reorganization or other change in the Company's capital structure or its business, any merger or consolidation of the Company, any issue of debt or equity securities ahead of or affecting Units or the rights thereof, the dissolution or liquidation of the Company or any sale, lease, exchange or other disposition of all or any part of its assets or business or any other corporate act or proceeding.

(b) Subdivision or Consolidation of Units. The terms of this Award shall be subject to adjustment from time to time, in accordance with the following provisions:

(i) If at any time, or from time to time, the Company shall subdivide as a whole (by reclassification, by a unit split, by the issuance of a dividend on Units payable in Units, or otherwise) the number of shares of Units then outstanding into a greater number of shares of Units, then the number of shares of Phantom Units specified in Section 1 above shall be increased proportionately.

(ii) If at any time, or from time to time, the Company shall consolidate as a whole (by reclassification, reverse unit split, or otherwise) the number of shares of Units then outstanding into a lesser number of shares of Units, the number of shares of Phantom Units specified in Section 1 above shall be decreased proportionately.

(iii) Whenever the number of shares of Units subject to this Award are required to be adjusted as provided in this Section 6(b), the Company shall promptly prepare and deliver to the Executive a notice setting forth, in reasonable detail, the event requiring adjustment, the amount of the adjustment, the method by which such adjustment was calculated, and the change in the number of shares of Phantom Units specified in Section 1 above after giving effect to the adjustments. The Company shall promptly give the Executive such a notice.

(iv) Adjustments under Sections 6(b)(i) and (ii) shall be made by the Company, and its determination as to what adjustments shall be made and the extent thereof shall be final, binding, and conclusive.

7. No Multiple Payments. Settlement of the Phantom Units shall not occur under more than one provision of this Agreement.

8. Information Confidential. As partial consideration for the granting of the Phantom Units hereunder, the Executive hereby agrees with the Company that the Executive will keep confidential all information and knowledge that the Executive has relating to the terms and conditions of this Agreement; provided, however, that such information may be disclosed as required by law and may be given in confidence to the Executive's spouse, tax and financial advisors, or to a financial institution to the extent that such information is necessary to secure a loan. In the event any breach of this promise comes to the attention of the Company, it shall take into consideration that breach in determining whether to recommend the grant of any future similar award to the Executive, as a factor militating against the advisability of granting any such future award to the Executive.

9. No Right to Continued Employment. This Agreement shall not be construed to confer upon the Executive any right to continue as an employee of the Company. Any question as to whether there has been a termination of such employment, and the cause of such termination, shall be determined by the Chief Executive Officer or the Board and its determination shall be final and binding.

10. Payment of Taxes. The Company may from time to time, in its discretion, require the Executive to pay the Company the amount that the Company deems necessary to satisfy the Company's current or future obligation to withhold federal, state or local income or other taxes incurred by the Executive as a result of the Award. With respect to any required tax withholding, (a) the Company may withhold from the cash payment to be paid to the Executive the amount necessary to satisfy the Company's obligation to withhold taxes, (b) with the Company's consent, the Executive may deliver sufficient cash to the Company to satisfy its tax withholding obligations, or (c) the withholding obligations may be met by any such other arrangement that is acceptable to the Company and the Executive. In the event that the Company subsequently determines that the amount withheld as payment of any tax withholding obligation is insufficient to discharge that tax withholding obligation, then the Executive shall pay to the Company, immediately upon the Company's request, the amount of that deficiency.

11. Administration. This Agreement shall at all times be subject to the terms and conditions of the Plan. The Company shall have sole and complete discretion with respect to all matters reserved to it by the Plan and all decisions of the Company with respect thereto and this Agreement shall be final and binding upon the Executive and the Company. In the event of any conflict between the terms and conditions of this Agreement and the Plan, the provisions of the Plan shall control.

12. Unfunded Arrangement. This Agreement and the Plan shall not give a Executive any security or other interest in any assets of the Company; rather the Executive's right to the Award is that of a general unsecured creditor of the Company.

13. No Liability for Good Faith Determinations. The Company and the members of the Board shall not be liable for any act, omission or determination taken or made in good faith with respect to this Agreement or the Phantom Units granted hereunder.

14. No Guarantee of Interests. The Company and the members of the Board do not guarantee the Units from loss or depreciation.

15. Company Records. Records of the Company regarding the Executive's period of service, termination of service and the reason therefor, leaves of absence, and other matters shall be conclusive for all purposes hereunder, unless determined by the Company to be incorrect.

16. Company Action. Any action required of the Company shall be by resolution of its Board or by a person authorized to act by resolution of the Board.

17. Severability. If any provision of this Agreement is held to be illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining provisions hereof, but such provision shall be fully severable and this Agreement shall be construed and enforced as if the illegal or invalid provision had never been included herein.

18. Notices. All notices required or permitted under this Agreement must be in writing and personally delivered or sent by mail and shall be deemed to be delivered on the date on which it is actually received by the person to whom it is properly addressed. A notice shall be effective when actually received by the Company in writing and in conformance with this Agreement and the Plan.

19. Waiver of Notice. Any person entitled to notice hereunder may waive such notice.

20. Successors. This Agreement shall be binding upon the Executive, the Executive's legal representatives, heirs, legatees and distributees, and upon the Company, its successors and assigns.

21. Headings. The titles and headings of Sections are included for convenience of reference only and are not to be considered in construction of the provisions hereof.

22. Governing Law. All questions arising with respect to the provisions of this Agreement shall be determined by application of the laws of the State of Delaware without regard to choice of law provisions thereunder, except to the extent Delaware law is preempted by federal law.

23. Word Usage. Words used in the masculine shall apply to the feminine where applicable, and wherever the context of this Agreement dictates, the plural shall be read as the singular and the singular as the plural.

24. Amendment. This Agreement may be amended by the Company; provided, however, that no amendment may decrease Executive's rights inherent in this Agreement prior to such amendment without Executive's express written consent. Notwithstanding the provisions of this Section 24, this Agreement may be amended by the Company, without the consent of the Executive, to the extent necessary to comply with applicable laws and regulations and to conform the provisions of this Agreement to any changes thereto or to settle the Award pursuant to all applicable provisions of the Plan.

25. Nonqualified Deferred Compensation Rules. In the event this Award fails to meet the limitations, requirements or exemptions of or from Section 409A of the Internal Revenue Code of 1986, as amended (the "***Code***"), or the laws, rules, and regulations promulgated in connection with Section 409A of the Code, then this Award shall be modified by the Company, in its sole discretion, to the limited extent necessary to satisfy such nonqualified deferred compensation rules.

IN WITNESS WHEREOF, the Company has caused this Agreement to be executed by its duly authorized officer effective as of June 18, 2010.

VANGUARD NATURAL RESOURCES, LLC

By: /s/ Scott W. Smith

Name: Scott W. Smith

Title: Chief Executive Officer and President

EXECUTIVE

/s/ Britt Pence
Britt Pence

EXHIBIT 31.1

CERTIFICATION

I, Scott W. Smith, certify that:

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

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

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

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

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2010

/s/ Scott W. Smith
Scott W. Smith
President and Chief Executive Officer
(Principal Executive Officer)
Vanguard Natural Resources, LLC

EXHIBIT 31.2

CERTIFICATION

I, Richard A. Robert, certify that:

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

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

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

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

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2010

/s/ Richard A. Robert
Richard A. Robert
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer and
Principal Accounting Officer)
Vanguard Natural Resources, LLC

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott W. Smith, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

August 4, 2010

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the “Company”) on Form 10-Q for the period ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Richard A. Robert, Executive Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Richard A. Robert

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

August 4, 2010