Vanguard Natural Resources, LLC
Form 10-Q
November 05, 2010

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2010

OR

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

For the transition period from to

Commission File Number: 001-33756

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

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

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

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

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

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

Common units outstanding on November 1, 2010: 26,352,499.

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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 “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”). References in this report to “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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Revenues:				
Natural gas, natural gas liquids and oil sales	$ 22,684	$ 11,324	$ 62,200	$ 29,930
Loss on commodity cash flow hedges	(568)	(463)	(2,127)	(1,737)
Realized gain on other commodity derivative contracts	6,513	8,010	18,274	23,794
Unrealized gain (loss) on other commodity derivative contracts	(9,388)	(12,220)	1,332	(16,492)
Total revenues	19,241	6,651	79,679	35,495
Costs and expenses:				
Lease operating expenses	4,838	3,322	13,545	9,233
Depreciation, depletion, amortization, and accretion	6,179	3,272	16,130	9,700
Impairment of natural gas and oil properties	—	—	—	63,818
Selling, general and administrative expenses	1,104	2,137	3,638	8,230
Production and other taxes	1,753	974	5,215	2,537
Total costs and expenses	13,874	9, 705	38,528	93,518
Income (loss) from operations	5,367	(3,054)	41,151	(58,023)
Other income and (expense):				
Interest expense	(1,708)	(1,042)	(4,522)	(3,034)
Realized loss on interest rate derivative contracts	(410)	(506)	(1,408)	(1,240)
Unrealized gain (loss) on interest rate derivative contracts	(1,337)	(575)	(2,021)	387
Gain (loss) on acquisition of natural gas and oil properties	—	5,878	(5,680)	5,878
Total other income (expense)	(3,455)	3,755	(13,631)	1,991
Net income (loss)	$ 1,912	$ 701	$ 27,520	$ (56,032)
Net income (loss) per Common and Class B units – basic	$ 0.09	$ 0.05	$ 1.35	$ (4.24)
Net income (loss) per Common and Class B units –diluted	$ 0.09	$ 0.05	$ 1.34	$ (4.24)

Weighted average units outstanding:				
Common units – basic	21,671	14,027	20,037	12,780
Common units – diluted	21,710	14,027	20,071	12,780
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)

	September 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 3,234	$ 487
Trade accounts receivable, net	9,249	8,025
Derivative assets	21,332	16,190
Other receivables	1,870	2,224
Other current assets	1,127	1,317
Total current assets	36,812	28,243
Natural gas and oil properties, at cost	522,272	399,212
Accumulated depletion	(242,630)	(226,687)
Natural gas and oil properties evaluated, net – full cost method	279,642	172,525
Other assets		
Derivative assets	1,198	5,225
Deferred financing costs	3,110	3,298
Other assets	1,227	1,409
Total assets	$ 321,989	$ 210,700
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 1,086	$ 766
Accounts payable – natural gas and oil	2,542	2,299
Payables to affiliates	1,100	1,387
Deferred swap premium liability	1,643	1,334
Derivative liabilities	340	253
Phantom unit compensation accrual	103	4,299
Accrued ad valorem taxes	1,756	903
Accrued expenses	768	1,178
Total current liabilities	9,338	12,419
Long-term debt	170,900	129,800
Derivative liabilities	5,759	2,036
Deferred swap premium liability	432	1,739
Asset retirement obligations	5,160	4,420
Total liabilities	191,589	150,414
Commitments and contingencies		
Members' equity		
	128,609	59,873

Members' capital, 21,729,999 common units issued and outstanding at September 30, 2010 and 18,416,173 at December 31, 2009		
Class B units, 420,000 issued and outstanding at September 30, 2010 and December 31, 2009	5,397	5,930
Accumulated other comprehensive loss	(3,606)	(5,517)
Total members' equity	130,400	60,286
Total liabilities and members' equity	$ 321,989	$ 210,700

See accompanying notes to consolidated financial statements

VANGUARD NATURAL RESOURCES, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010 AND THE YEAR ENDED DECEMBER 31, 2009
(in thousands, except per 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 and $0.55 per unit to unitholders of record August 6, 2010)	—	(31,253)	—	(672)	—	(31,925)
Issuance of common units, net of offering costs of $203	3,314	72,984	—	—	—	72,984
Unit-based compensation	—	(515)	—	139	—	(376)
Net income	—	27,520	—	—	—	27,520
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	1,911	1,911
Balance at September 30, 2010	21,730	$128,609	420	$5,397	$ (3,606)	$130,400

See accompanying notes to consolidated financial statements

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Operating activities		
Net income (loss)	$27,520	$(56,032)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	16,130	9,700
Impairment of natural gas and oil properties	—	63,818
Amortization of deferred financing costs	962	363
Unit-based compensation	656	2,311
Unrealized fair value of phantom units granted to officers	103	3,034
Amortization of premiums paid on derivative contracts	1,479	2,676
Amortization of value on derivative contracts acquired	1,657	1,707
Unrealized losses on other commodity and interest rate derivative contracts	689	16,105
Loss (gain) on acquisition of natural gas and oil properties	5,680	(5,878)
Changes in operating assets and liabilities:		
Trade accounts receivable	(1,224)	673
Other receivables	354	(149)
Payables to affiliates	(286)	(1,689)
Other current assets	(39)	11
Price risk management activities, net	(217)	(13)
Accounts payable	564	(1,339)
Accrued expenses	(2,998)	687
Other assets	(23)	(27)
Net cash provided by operating activities	51,007	35,958
Investing activities		
Additions to property and equipment	(168)	(9)
Additions to natural gas and oil properties	(13,220)	(2,981)
Acquisitions of natural gas and oil properties	(114,531)	(49,964)
Deposits and prepayments of natural gas and oil properties	(66)	(699)
Net cash used in investing activities	(127,985)	(53,653)
Financing activities		
Proceeds from borrowings	132,700	16,800
Repayment of debt	(91,600)	(28,300)
Proceeds from equity offering, net	72,984	53,192
Distributions to members	(31,925)	(18,849)
Financing costs	(774)	(2,781)
Prepaid offering costs	(239)	—
Purchase of units for issuance as unit-based compensation	(1,421)	(324)
Net cash provided by financing activities	79,725	19,738
Net increase in cash and cash equivalents	2,747	2,043

Cash and cash equivalents, beginning of period	487	3
Cash and cash equivalents, end of period	$3,234	$2,046
Supplemental cash flow information:		
Cash paid for interest	$3,516	$2,946
Non-cash financing and investing activities:		
Asset retirement obligations	$619	$1,913
Derivatives assumed in acquisition of natural gas and oil properties	$—	$4,128
Deferred swap liability	$—	$3,072
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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income (loss)	$ 1,912	$ 701	$ 27,520	$ (56,032)
Net gains from derivative contracts:				
Reclassification adjustments for settlements	467	434	1,911	1,678
Other comprehensive income	467	434	1,911	1,678
Comprehensive income (loss)	$ 2,379	$ 1,135	$ 29,431	$ (54,354)

See accompanying notes to consolidated financial statements

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

Description of the Business:

We are a publicly-traded limited liability company focused on the acquisition and development of mature, long-lived 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, I 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 September 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 September 30, 2010 and December 31, 2009 and for the three and nine months ended September 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 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) 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 of $50.5 million considered purchase price adjustments of approximately $1.8 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.

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 Sun TSH acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $5.9 million, calculated in the following table. The gain resulted from the changes in natural gas and 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 statements of operations.

		(in thousands)
Fair value of assets and liabilities acquired:		
Natural gas and oil properties	$	54,584
Derivative assets		4,128
Other currents assets		187
Accrued expenses		(298)
Asset retirement obligations		(2,254)
Total fair value of assets and liabilities acquired		56,347
Fair value of consideration transferred		50,469
Gain on acquisition of natural gas and oil properties	$	5,878

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. 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.

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 Ward County acquisitions as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $1.1 million, calculated in the following table. The gain resulted from the changes in natural gas and 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	$	56,347
Other currents assets		25
Asset retirement obligations		(248)
Total fair value of assets and liabilities acquired		56,124
Fair value of consideration transferred		55,021
Gain on acquisition of natural gas and oil properties	$	1,103

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. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 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 goodwill of $5.7 million, calculated in the following table, which was immediately impaired and recorded as a loss. 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	$	107,598
Other assets		1,505
Asset retirement obligations		(500)
Total fair value of assets and liabilities acquired		108,603
Fair value of consideration transferred		114,283
Loss on acquisition of natural gas and oil properties	$	(5,680)

The following unaudited pro forma results for the three months ended September 30, 2009 and nine months ended September 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 gain recognized on the Ward acquisition of $1.1 million and the loss recognized on the Parker Creek acquisition of $5.7 million was excluded from the pro forma results for the three and nine months ended September 30, 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 and (4) 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):

	Pro Forma (in thousands, except per unit data)		
	Three Months Ended September 30,	Nine Months Ended September 30,	
	2009	2010	2009
Total revenues	$ 14,776	$ 86,157	$ 58,651
Net income (loss)	$ 4,609	$ 31,973	$ (44,769)
Net income (loss) per unit:			
Common & Class B units – basic	$ 0.21	$ 1.56	$ (2.19)
Common & Class B units – diluted	$ 0.21	$ 1.56	$ (2.19)

The amount of revenues and excess of revenues over direct operating expenses included in our 2009 and 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 September 30, 2010	Nine Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
		(in thousands)		
Sun TSH				
Revenues	$ 2,746	$ 9,106	$ 1,294	$ 1,294
Excess of revenues over direct operating expenses	$ 1,525	$ 5,157	$ 950	$ 950
Ward County				
Revenues	$ 3,864	$ 11,100	$ —	$ —
Excess of revenues over direct operating expenses	$ 2,689	$ 7,396	$ —	$ —
Parker Creek				
Revenues	$ 4,712	$ 6,750	$ —	$ —
Excess of revenues over direct operating expenses	$ 3,961	$ 5,670	$ —	$ —

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 September 30, 2010	Amount Outstanding December 31, 2009
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 170,900	$ 129,800
			$ 170,900	$ 129,800

(1) Variable interest rate was 2.8% and 2.7% at September 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. 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. 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 $170.9 million at September 30, 2010. In November 2010, our borrowing base under the reserve-based credit facility was amended pursuant to our semi-annual redetermination. See Note 11. Subsequent Events for further discussion.

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 September 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 September 30, 2010, we were in an over hedged position in 2010 natural gas volumes but were in compliance with all of our other debt covenants. See Note 11. Subsequent Events for discussion of waiver granted by our lenders.

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 under swaption agreements. 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 with certain counterparties that are lenders under our reserve-based credit facility as named above, as well as with Credit Agricole, 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 separated between 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 September 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
October 1, 2010 - December 31, 2010	1,017,705	$ 10.73	90,100	$ 87.17
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 under swaption agreements 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		
	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
Production Period:						
October 1, 2010 - December 31, 2010	542,800	$ 7.67	$ 8.94	46,000	$ 70.00	$ 80.00
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
	—	$ —	$ —	45,625	$ 80.00	$ 100.25

January 1, 2013
- December 31,
2013

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Interest Rate Swaps

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

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

		Notional Amount	Fixed Libor Rates
Period:			
October 1, 2010 to December 18, 2010	$	10,000	1.50%
October 1, 2010 to December 20, 2010	$	10,000	1.85%
October 1, 2010 to March 31, 2011	$	20,000	2.08%
October 1, 2010 to December 10, 2012	$	20,000	3.35%
October 1, 2010 to January 31, 2013	$	20,000	2.38%
October 1, 2010 to January 31, 2013	$	20,000	2.66%
August 6, 2012 to August 6, 2014	$	25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$	30,000	2.25%

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018.

Balance Sheet Presentation

Our commodity derivatives and interest rate swap derivatives are presented on a net basis in “derivative assets” and “derivative liabilities” on the consolidated balance sheets. The following summarizes the fair value of derivatives outstanding on a gross basis (in thousands).

	September 30, 2010	December 31, 2009
Assets:		
Commodity derivatives	$ 30,440	$ 34,753
	$ 30,440	$ 34,753
Liabilities:		
Commodity derivatives	$ (9,766)	$ (13,405)
Interest rate swaps	(4,243)	(2,222)
	$ (14,009)	$ (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 $30.4 million at September 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 September 30, 2010.

Gain (Loss) on Derivatives

Gains and losses on derivatives are reported on the consolidated statement of operations in "realized or unrealized gain (loss) on other commodity derivative contracts" and "realized or unrealized gain (loss) on interest rate derivative contracts." Realized gains (losses) represent amounts related to the settlement of derivative instruments. Unrealized gains (losses) represent the change in fair value of the derivative instruments to be settled in the future and are non-cash items which fluctuate in value as commodity prices and interest rates change.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Realized gains (losses):				
Other commodity derivatives	$ 6,513	$ 8,010	$ 18,274	$ 23,794
Interest rate swaps	(410)	(506)	(1,408)	(1,240)
	$ 6,103	$ 7,504	$ 16,866	$ 22,554
Unrealized gains (losses):				
Other commodity derivatives	$ (9,388)	$ (12,220)	$ 1,332	$ (16,492)
Interest rate swaps	(1,337)	(575)	(2,021)	387
	$ (10,725)	$ (12,795)	$ (689)	$ (16,105)
Total gains (losses):				
Other commodity derivatives	$ (2,875)	$ (4,210)	$ 19,606	$ 7,302
Interest rate swaps	(1,747)	(1,081)	(3,429)	(853)
	$ (4,622)	$ (5,291)	$ 16,177	$ 6,449

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, options and swaptions. 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 of our derivative contracts as Level 2.

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

	September 30, 2010			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 22,530	$ —	$ 22,530
Total derivative instruments	$ —	$ 22,530	$ —	$ 22,530
Liabilities:				
Commodity price derivative contracts	$ —	$ (1,856)	$ —	$ (1,856)
Interest rate derivative contracts	—	(4,243)	—	(4,243)
Total derivative instruments	$ —	$ (6,099)	$ —	$ (6,099)

	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 nine months ended September 30, 2010, in connection with natural gas and oil properties acquired, we incurred and recorded asset retirement obligations totaling $0.6 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 (2.3%). 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 September 30 reported on our consolidated balance sheets and the changes in the asset retirement obligations for the nine months ended September 30, were as follows (in thousands):

	2010	2009
Asset retirement obligations at January 1,	$ 4,420	$ 2,134
Liabilities added during the current period	619	2,254
Accretion expense	121	86
Revisions of estimates	—	(341)
Asset retirement obligation at September 30,	$ 5,160	$ 4,133

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. In June 2010, we began discussions with Vinland regarding an amendment to the GCA to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis since then, however, no formal agreement between us and Vinland has been signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the GCA. In the event no agreement is reached between us and Vinland, all the terms of the agreements will revert back to the original agreements effective July 1, 2010. 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 September 30, 2010 and 2009 and $1.5 million and $1.2 million for the nine months ended September 30, 2010 and 2009, respectively. Costs incurred under the GCA were $0.4 million for each of the three months ended September 30, 2010 and 2009 and $1.1 million and $0.9 million for the nine months ended September 30, 2010 and 2009, respectively. A payable of $1.1 million and $1.4 million, respectively, is reflected on our September 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 September 30, 2010, beneficially owned 12.29% 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 September 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 nine months ended September 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 38,654 and 33,657 additional common units, respectively, 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 nine months ended September 30, 2009, these 175,000 options had no dilutive effect as the exercise price was higher than the average market price for the three and nine month periods ended September 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 nine months ended September 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 nine months ended September 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 nine months ended September 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 in April 2009, 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 in April and May 2010, three years after the date of grant. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future.

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 agreements, 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 ($3.4 million in cash and 38,960 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. At September 30, 2009, an accrued liability and non-cash unit-based compensation expense of $3.0 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 common 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 September 30, 2010, an accrued liability of $0.1 million has been recorded and non-cash unit-based compensation expense of $0.06 million and $0.1 million has been recognized for the three month and nine month periods ended September 30, 2010, respectively, 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 September 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 September 30, 2010	66,719	$ 22.18

At September 30, 2010, there was approximately $1.0 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 1.6 years. Our consolidated statements of operations reflects non-cash compensation of $0.3 million and $1.3 million in the selling, general and administrative line item for the three months ended September 30, 2010 and 2009 and $0.8 million and $5.3 million for the nine months ended September 30, 2010 and 2009, respectively.

10. Shelf Registration Statements

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million 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 2009 shelf registration statement is 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 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 $0.1 million.

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. Net proceeds, terms and pricing of the offering of securities issued under the 2010 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 October 2010, we completed an offering of 4.8 million of our common units. See Note 11. Subsequent Events for further discussion.

In August 2010, we entered into an equity distribution agreement relating to our common units representing limited liability company interests having an aggregate offering price of up to $60.0 million. In accordance with the terms of the equity distribution agreement we may offer and sell up to the maximum dollar amount of our units from time to time through our sales agent. Sales of the units, if any, may be made by means of ordinary brokers' transactions through the facilities of the New York Stock Exchange, or NYSE, at market prices. Our sales agent will receive from us a commission of 1.25% based on the gross sales price per unit for any units sold through it as agent under the equity distribution agreement. During September 2010, we received net proceeds of approximately $1.6 million from the sales of 63,826 common units, after commissions.

As a result of these offerings, as of September 30, 2010, we have approximately $62.6 million and $800.0 million remaining available under our 2009 and 2010 shelf registration statements, respectively.

11. Subsequent Events

In October 2010, we completed an offering of 4.8 million of our common units. The units were offered to the public at a price of $25.40 per unit. We received net proceeds of approximately $116.2 million from the offering, after deducting underwriting discounts of $5.1 million. We paid $3.7 million of the proceeds of this offering to redeem 150,000 common units from our largest unitholder. The net proceeds of $112.5 million were used to pay down outstanding borrowings under our reserve-based credit facility.

In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. All other terms under the reserve-based credit facility remained the same. At September 30, 2010 we had hedged 85.9% of our expected natural gas production for the remainder of 2010, which is in excess of the maximum permitted by the credit agreement of 85%. Our lenders issued a waiver for this over hedged position in 2010 natural gas volumes. Additionally, we received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged no greater than 85% of the actual outstanding balance.

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

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 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 2,120 gross (1,216 net) productive wells at September 30, 2010, and our average net production for the year ended December 31, 2009 and for the nine months ended September 30, 2010 was 20,010 Mcfe per day and 27,995 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 September 30, 2010, approximately 32% or 56.3 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 to our reserve-based credit facility in June 2010 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 nine months of 2010, our unit price rose from a closing low of $18.93 on May 20, 2010 to a closing high of $26.20 on September 28, 2010. During the nine months ended September 30, 2010, we completed one gross (one net) well on an operated property, drilled and completed one gross (one net) operated well and drilled and completed five gross (2.2 net) non-operated wells. Furthermore, we completed the Parker Creek acquisition as described below. We intend to move forward with our development drilling program during the fourth quarter 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, drilling a limited number of wells which we believe will provide an adequate return on the investment and making accretive acquisitions of natural gas and oil properties.

Sun TSH Acquisition

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, 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 the Company's 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 then-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 price with a total cost to the Company of $3.1 million, which was financed through deferred premiums. As of September 30,2010, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 34.7 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. 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 September 30, 2010, based on internal reserve estimates, these acquired properties had estimated proved reserves of 3.5 million barrels of oil equivalent, 81% of which is oil and 60% 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 at a weighted average price of $86.85 per barrel.

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. The adjusted purchase price of $114.3 million considered final purchase price adjustments of approximately $1.2 million. The purchase price was funded from the approximate $71.5 million in net proceeds from our May 2010 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 September 30, 2010, based on internal reserve estimates, these acquired properties had estimated proved reserves of 4.6 million barrels of oil equivalent, 97% of which is oil and 60% 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. 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. In February 2009, a third amendment to our reserve-based credit facility 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 $170.9 million at September 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%

In November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. All other terms under the reserve-based credit facility remained the same. At September 30, 2010 we had hedged 85.9% of our expected natural gas production for the remainder of 2010, which is in excess of the maximum permitted by the credit agreement of 85%. Our lenders issued a waiver for this over hedged position in 2010 natural gas volumes. Additionally, we received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged no greater than 85% of the actual outstanding balance.

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 nine months ended September 30, 2010, we completed one gross (one net) well on an operated property, drilled and completed one gross (one net) operated well and drilled and completed five gross (2.2 net) non-operated wells. In addition, we anticipate that during the fourth quarter of 2010 we will complete five vertical oil wells in Appalachia at a total cost of approximately $1.5 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 cash flow at existing levels over the long-term provided that it is economical to do so based on the commodity price environment. However, we cannot be certain that we will be able to issue our debt or equity securities on favorable terms, or at all, and we may be unable to refinance our 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 September 30,		Nine Months Ended September 30,	
	2010	2009(a)(b)(c)	2010(c)	2009(a)(b)(c)
Revenues:				
Natural gas sales	$ 6,399	$ 4,742	$ 20,302	$ 15,500
Natural gas liquids sales	2,169	1,136	7,094	1,811
Oil sales	14,116	5,446	34,804	12,619
Natural gas, natural gas liquids and oil sales	22,684	11,324	62,200	29,930
Loss on commodity cash flow hedges	(568)	(463)	(2,127)	(1,737)
Realized gain on other commodity derivative contracts	6,513	8,010	18,274	23,794
Unrealized gain (loss) on other commodity derivative contracts	(9,388)	(12,220)	1,332	(16,492)
Total revenues	$ 19,241	$ 6,651	$ 79,679	$ 35,495
Costs and expenses:				
Lease operating expenses	$ 4,838	$ 3,322	$ 13,545	$ 9,233
Depreciation, depletion, amortization, and accretion	6,179	3,272	16,130	9,700
Impairment of natural gas and oil properties	—	—	—	63,818
Selling, general and administrative expenses	1,104	2,137	3,638	8,230
Production and other taxes	1,753	974	5,215	2,537
Total costs and expenses	$ 13,874	$ 9,705	$ 38,528	$ 93,518

Other income and (expense):											
Interest expense, net	$	(1,708	)	$	(1,042	)	$	(4,522	)	$	(3,034	)
Realized loss on interest rate derivative contracts	$	(410	)	$	(506	)	$	(1,408	)	$	(1,240	)
Unrealized gain (loss) on interest rate derivative contracts	$	(1,337	)	$	(575	)	$	(2,021	)	$	387	
Gain (loss) on acquisition of natural gas and oil properties	$	—		$	5,878		$	(5,680	)	$	5,878	

(a) The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately one and a half months of operations are included in the three month and nine month periods ended September 30, 2009.
(b) The Ward County acquisition closed on December 2, 2009 and, as such, no operations are included in the three month or nine month periods ended September 30, 2009.
(c) The Parker Creek acquisition closed on May 20, 2010 and, as such, only four months and eleven days of operations are included in the nine month period ended September 30, 2010, and no operations are included in the three or nine month periods ended September 30, 2009.

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

Revenues

Natural gas, natural gas liquids and oil sales increased $11.4 million to $22.7 million during the three months ended September 30, 2010 as compared to the same period in 2009. The key revenue measurements were as follows:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	762	773	(1)%
Permian gas (MMcf)	100	57(b)	75%
South Texas gas (MMcf)	427	335(a)(c)	27%
Total natural gas production (MMcf)	1,289	1,165	11%
Average Appalachian daily gas production (Mcf/day)	8,276	8,403	(1)%
Average Permian daily gas production (Mcf/day)	1,087	617(b)	76%
Average South Texas daily gas production (Mcf/day)	4,646	3,646(a)(c)	27%
Average Vanguard daily gas production (Mcf/day)	14,009	12,666	11%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$9.56(d)	$11.12(d)	(14)%
Net realized gas price, excluding hedges	$4.97	$4.07	22%
Net Oil Production:			
Appalachian oil (Bbls)	27,971	25,452	10%
Permian oil (Bbls)	103,327	57,525(b)	80%
South Texas oil (Bbls)	5,341	2,425(a)(c)	120%
Mississippi oil (Bbls)	63,650	—(a)	—
Total oil production (Bbls)	200,289	85,402	135%
Average Appalachian daily oil production (Bbls/day)	304	277	10%
Average Permian daily oil production (Bbls/day)	1,123	625(b)	80%
Average South Texas daily oil production (Bbls/day)	58	26(a)(c)	123%
Average Mississippi daily oil production (Bbls/day)	692	—(a)	—
Average Vanguard daily oil production (Bbls/day)	2,177	928	135%

Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$75.46(d)	$77.15(d)	(2)%
Net realized oil price, excluding hedges	$70.48	$63.76	11%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	397,572	105,336(b)	277%
South Texas natural gas liquids (Gal)	1,796,659	1,285,876(a)(c)	40%
Total natural gas liquids production (Gal)	2,194,231	1,391,212	58%
Average Permian daily natural gas liquids production (Gal/day)	4,321	1,145(b)	277%
Average South Texas daily natural gas liquids production (Gal/day)	19,529	13,977(a)(c)	40%
Average Vanguard daily natural gas liquids production (Gal/day)	23,850	15,122	58%
Average Net Realized Natural Gas Liquids Sales Price per Gal	$0.99	$0.82	21%

(a) The Parker Creek acquisition closed on May 20, 2010 and, as such, no operations are included in the three month period ended September 30, 2009.

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

(c) The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately one and a half months of operations are included in the three month period ended September 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 September 30, 2010 compared to the same period in 2009 was due primarily to the increases in production from our acquisitions. We experienced a 22% increase in the average realized natural gas sales price received (excluding hedges) and a 11% increase in the average realized oil price (excluding hedges). Additionally, our total production increased by 49% on an Mcfe basis. The increase in production for the three months ended September 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 1% decrease in natural gas production which was largely offset by a 10% increase in oil production during the three months ended September 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 10% 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 September 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 $9.4 million loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. These realized and unrealized gains and losses resulted from the changes in commodity prices and the effect of these price changes is discussed in the paragraph below. During the three months ended September 30, 2010 and 2009, the Company recognized $0.6 million and $0.5 million in losses on commodity cash flow hedges that meet the criteria for cash flow hedge accounting, respectively. 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 September 30, 2010 and 2009 relate to amounts that settled in the respective periods which have been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and 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. In June 2010, we began discussions with Vinland regarding an amendment to the gathering and compression agreement to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis although the formal agreements have yet to be signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the gathering and compression agreement. Lease operating expenses increased by $1.5 million to $4.8 million for the three months ended September 30, 2010 as compared to the three months ended September 30, 2009, of which $1.1 million related primarily to the Sun TSH, Ward County and Parker Creek acquisitions and $0.4 million related to increased lease operating expenses for wells in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $6.2 million for the three months ended September 30, 2010 from approximately $3.3 million for the three months ended September 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 September 30, 2010 decreased $1.0 million as compared to the three months ended September 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 $1.1 million to $0.2 million for the three months ended September 30, 2010. All other cash selling, general and administrative expenses increased $0.1 million during the three months ended September 30, 2010 as compared to the same period in 2009 principally due to higher compensation related expenses, offset by 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 $0.8 million for the three months ended September 30, 2010 as compared to the same period in 2009. Severance taxes increased by $0.6 million as a result of increased natural gas, natural gas liquids and oil sales. 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.

Other Income and Expense

Interest expense increased to $1.7 million for the three months ended September 30, 2010 compared to $1.0 million for the three months ended September 30, 2009 primarily due to higher average outstanding debt during the three months ended September 30, 2010.

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Revenues

Natural gas, natural gas liquids and oil sales increased $32.3 million to $62.2 million during the nine months ended September 30, 2010 as compared to the same period in 2009. The key revenue measurements were as follows:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	2,198	2,372	(7)%
Permian gas (MMcf)	279	153(b)	82%
South Texas gas (MMcf)	1,287(a)	763(a)(c)	69%
Total natural gas production (MMcf)	3,764	3,288	14%
Average Appalachian daily gas production (Mcf/day)	8,050	8,691	(7)%
Average Permian daily gas production (Mcf/day)	1,023	560(b)	83%
Average South Texas daily gas production (Mcf/day)	4,715(a)	2,795(a)(c)	69%
Average Vanguard daily gas production (Mcf/day)	13,788	12,046	14%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$ 9.92(d)	$ 11.13(d)	(11)%
Net realized gas price, excluding hedges	$ 5.39	$ 4.71	14%
Net Oil Production:			
Appalachian oil (Bbls)	89,301	63,149	41%
Permian oil (Bbls)	291,565	175,174(b)	66%
South Texas oil (Bbls)	15,793(a)	2,425(a)(c)	551%
Mississippi oil (Bbls)	90,486(a)	—(a)	—
Total oil production (Bbls)	487,145	240,748	102%
Average Appalachian daily oil production (Bbls/day)	327	231	42%
Average Permian daily oil production (Bbls/day)	1,068	642(b)	66%
Average South Texas daily oil production (Bbls/day)	58(a)	9(a)(c)	544%
Average Mississippi daily oil production (Bbls/day)	331(a)	—(a)	—
Average Vanguard daily oil production (Bbls/day)	1,784	882	102%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$ 76.09(d)	$ 74.64(d)	2%
Net realized oil price, excluding hedges	$ 71.44	$ 52.42	36%

Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	1,082,037	340,536(b)	218%
South Texas natural gas liquids (Gal)	5,622,997	2,117,113(c)	166%
Total natural gas liquids production (Gal)	6,705,034	2,457,649	173%
Average Permian daily natural gas liquids production (Gal/day)	3,963	1,247(b)	218%
Average South Texas daily natural gas liquids production (Gal/day)	20,597	7,755(c)	166%
Average Vanguard daily natural gas liquids production (Gal/day)	24,560	9,002	173%
Average Net Realized Natural Gas Liquids Sales Price per Gal	$1.06	$ 0.74	43%

(a) South Texas area includes production from the Dos Hermanos, Sun TSH and a portion of the Parker Creek acquisitions. The Parker Creek acquisition closed on May 20, 2010 and, as such, only four month and eleven days of operations are included in the nine month period ended September 30, 2010, and no operations are included in the nine month period ended September 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 4,798Mcf/day of natural gas and 69 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 26 Mcf/day of natural gas and 591 Bbls/day of oil.

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

(c) The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately one and a half months of operations are included in the nine month period ended September 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 nine months ended September 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 a 14% increase in the average realized natural gas sales price received (excluding hedges) and a 36% increase in the average realized oil price (excluding hedges). Additionally, our total production increased by 50% on a Mcfe basis. The increase in production for the nine months ended September 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 7% decrease in natural gas production which was partially offset by a 41% increase in oil production during the nine months ended September 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 was largely attributable to our decision to drill only one well in 2010 due to low natural gas prices. The 41% 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 nine months ended September 30, 2010, the Company recognized an $18.3 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $1.3 million gain related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting. During the nine months ended September 30, 2010 and 2009, the Company recognized $2.1 million and $1.7 million in losses on commodity cash flow hedges that meet the criteria for cash flow hedge accounting, respectively. 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 nine months ended September 30, 2010 and 2009 relate to amounts that settled in the respective periods which have been reclassified to earnings from accumulated other comprehensive loss.

The purpose of our hedging program is to mitigate the volatility in our operating cash flow. Depending on the type of derivative contract used, hedging generally achieves this by the counterparty paying us when commodity prices are below the hedged price and 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. In June 2010, we began discussions with Vinland regarding an amendment to the gathering and compression agreement to go into effect beginning on July 1, 2010. The amended agreement would provide gathering and compression services based upon actual costs plus a margin of $.055 per mcf. We and Vinland agreed in principle to this change effective July 1, 2010 and we have jointly operated on this basis although the formal agreements have yet to be signed. We are currently negotiating other agreements with Vinland concerning our joint operations and our intent is to have all our operations governed under a single set of agreements, including this amendment to the gathering and compression agreement. Lease operating expenses increased by $4.3 million to $13.5 million for the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2009, of which $2.5 million related primarily to the Sun TSH, Ward County and Parker Creek acquisitions and $1.8 million related to increased lease operating expenses for wells in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $16.1 million for the nine months ended September 30, 2010 from approximately $9.7 million for the nine months ended September 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 nine months ended September 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 during the nine months ended September 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 nine months ended September 30, 2010 decreased $4.6 million as compared to the nine months ended September 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 $4.6 million to $0.8 million for the nine months ended September 30, 2010. All other cash selling, general and administrative expenses remained relatively stable during the nine months ended September 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 and by county and are based on the value of our reserves. Production and other taxes increased by $2.7 million for the nine months ended September 30, 2010 as compared to the same period in 2009. Severance taxes increased by $1.8 million as a result of increased natural gas, natural gas liquids and oil sales. Texas margin and other corporate taxes increased by $0.5 million and ad valorem taxes increased by $0.4 million primarily due to the taxes on natural gas and oil properties acquired in the Sun TSH, Ward County and Parker Creek acquisitions.

Other Income and Expense

Interest expense increased to $4.5 million for the nine months ended September 30, 2010 compared to $3.0 million for the nine months ended September 30, 2009 primarily due to higher average outstanding debt and higher interest rates during the nine months ended September 30, 2010.

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 for the nine months ended September 30, 2010. The measurement of the fair value at acquisition date of the assets acquired in the Sun TSH acquisitions as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $5.9 million for the nine months ended September 30, 2009. This gain and loss resulted from the increases and decreases in natural gas and oil prices used to value the reserves.

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 September 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 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.

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 September 30, 2010 ranged from a high of $86.54 to a low of $64.78 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2010 to September 30, 2010 ranged from a high of $6.01 to a low of $3.65. As of November 1, 2010, the crude oil spot price per barrel was $82.94 and the NYMEX natural gas spot price per MMBtu was $3.83.

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.

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 November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. All other terms under the reserve-based credit facility remained the same. At September 30, 2010 we had hedged 85.9% of our expected natural gas production for the remainder of 2010, which is in excess of the maximum permitted by the credit agreement of 85%. Our lenders issued a waiver for this over hedged position in 2010 natural gas volumes. Additionally, we received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged no greater than 85% of the actual outstanding balance. As of November 5, 2010, we have $171.0 million available to be borrowed under our reserve-based credit facility. 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 further decreases in our borrowing base availability in the future. Our next borrowing base redetermination is scheduled for April 2011 utilizing our December 31, 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 November 5, 2010, our borrowings represented 24% of our borrowing base. Absent accretive acquisitions, to the extent available after unitholder distributions, debt service, and capital expenditures, it is our intention to utilize our excess cash flow to reduce our borrowings under our reserve-based credit facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient for the conduct of our business and operations for the foreseeable future.

Cash Flow from Operations

Net cash provided by operating activities was $51.0 million during the nine months ended September 30, 2010, compared to $36.0 million during the nine months ended September 30, 2009. The increase in cash provided by operating activities during the nine months ended September 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 $3.9 million in 2010 compared to decreasing total cash flows by $1.8 million in 2009. Contributing to the decrease in working capital during 2010 was a $3.0 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 non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the nine months ended September 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, swaptions and NYMEX collars 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 $128.0 million for the nine months ended September 30, 2010, compared to $53.7 million during the same period in 2009. The increase in cash used in investing activities was primarily attributable to $114.5 million for the acquisition of natural gas and oil properties in the Parker Creek acquisition, $13.2 million for the drilling and development of natural gas and oil properties and $0.07 million for prepayments for the drilling and development of natural gas and oil properties as compared to $50.0 million used for the Sun TSH acquisition and $3.0 million for the drilling and development of natural gas and oil properties during the nine months ended September 30, 2009.

Cash Flow from Financing Activities

Cash provided by financing activities was approximately $79.7 million for the nine months ended September 30, 2010, compared to cash provided of $19.7 million for the nine months ended September 30, 2009. During the nine months ended September 30, 2010, total net borrowings under our reserve-based credit facility were $41.1 million and total proceeds from our public equity offerings were $73.0 million, net of offering costs of $0.2 million. Our borrowings and proceeds from equity offerings were primarily used to finance the Parker Creek acquisition. Offsetting the cash provided by financing activities during the nine months ended September 30, 2010, was cash used of $31.9 million for distributions to unitholders. Cash provided by financing activities during the nine months ended September 30, 2009, included $11.5 million in net repayments under our reserve-based credit facility and $18.8 million used in distribution to unitholders. Proceeds from the equity offering of 3.9 million common units completed in August 2009 provided financing cash flows totaling $53.2 million, net of offering costs of $0.5 million, during the nine months ended September 30, 2009.

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. 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 September 30, 2010, we had $170.9 million outstanding 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 November 2010, our borrowing base under the reserve-based credit facility was reduced from $240.0 million to $225.0 million pursuant to our semi-annual redetermination. All other terms under the reserve-based credit facility remained the same. At September 30, 2010 we had hedged 85.9% of our expected natural gas production for the remainder of 2010, which is in excess of the maximum permitted by the credit agreement of 85%. Our lenders issued a waiver for this over hedged position in 2010 natural gas volumes. Additionally, we received a waiver through April 2011 for an over hedged position in interest rate derivatives which occurred in October 2010 as a result of the reduction of outstanding borrowings utilizing the net proceeds of the October common unit offering. The credit agreement limits the amount of outstanding debt to be hedged no greater than 85% of the actual outstanding balance. As of November 5, 2010 we had $54.0 million outstanding after the application of the proceeds from the October 2010 equity offering and as such, our availability under the reserve-based credit facility is $171.0 million. Our next borrowing base redetermination is scheduled for April 2011 utilizing our December 31, 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 further 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 November 5, 2010, our borrowings represented 24% 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 the fourth quarter of 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 September 30, 2010, we had elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

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

- incur indebtedness;

- grant certain liens;

- make certain loans, acquisitions, capital expenditures and investments;

- 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 after consideration of the waivers granted in conjunction with the recent redetermination of our borrowing base. 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 September 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 September 30, 2010, there were no loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of September 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	$ 208	$ 830	$ 830	$ 97	$ —	$ —	$ 1,965
Asset retirement obligations	—	493	86	136	134	4,311	5,160
Derivative liabilities	2,304	284	1,762	2,319	2,310	5,030	14,009
Long-term debt (1)	—	—	170,900	—	—	—	170,900
Operating leases	29	122	130	32	—	—	313
Total	$ 2,541	$ 1,729	$ 173,708	$ 2,584	$ 2,444	$ 9,341	$ 192,347

(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;
- Gains and losses on acquisitions of natural gas and oil properties;
- 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 September 30, 2010 as compared to the three months ended September 30, 2009, Adjusted EBITDA increased 42%, from $15.6 million to $22.2 million. For the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2009, Adjusted EBITDA increased 44%, from $41.5 million to $59.8 million. The following table presents a reconciliation of consolidated net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended September 30,	Nine Months Ended September 30,

	2010	2009	2010	2009
Net income (loss)	$ 1,912	$ 701	$ 27,520	$ (56,032)
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	2,118	1,548	5,930	4,274
Depreciation, depletion, amortization, and accretion	6,179	3,272	16,130	9,700
Impairment of natural gas and oil properties	—	—	—	63,818
Amortization of premiums paid on derivative contracts	481	858	1,479	2,676
Amortization of value on derivative contracts acquired	489	953	1,657	1,707
Unrealized losses on other commodity and interest rate derivative contracts	10,725	12,795	689	16,105
(Gain) loss on acquisition of natural gas and oil properties	—	(5,878)	5,680	(5,878)
Deferred taxes	12	(3)	(37)	(204)
Unit-based compensation expense	190	548	656	2,311
Unrealized fair value of phantom units granted to officers	55	782	103	3,034
Adjusted EBITDA	$ 22,161	$ 15,576	$ 59,807	$ 41,511

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 September 30, 2010 or 2009 or for the nine months ended September 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 under swaption agreements. 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 it believes that it can take advantage of an unusual market condition allowing us to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At September 30, 2010, the fair value of commodity derivative contracts was an asset of approximately $20.7 million, of which $21.3 million settles during the next twelve months.

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

	October 1, - December 31, 2010	Year 2011	Year 2012	Year 2013	Year 2014
Gas Positions:					
Fixed Price Swaps:					
Notional Volume (MMBtu)	1,017,705	3,328,312	—	—	—
Fixed Price ($/MMBtu)	$ 10.73	$ 7.83	$ —	$ —	$ —
Collars:					
Notional Volume (MMBtu)	542,800	1,933,500	—	—	—
Floor Price ($/MMBtu)	$ 7.67	$ 7.34	$ —	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.94	$ 8.44	$ —	$ —	$ —
Total:					
Notional Volume (MMBtu)	1,560,505	5,261,812	—	—	—
Oil Positions:					
Fixed Price Swaps:					
Notional Volume (Bbls)	90,100	443,250	347,700	296,400	209,875
Fixed Price ($/Bbl)	$ 87.17	$ 87.94	$ 90.03	$ 89.84	$ 94.37
Collars:					
Notional Volume (Bbls)	46,000	—	45,750	45,625	—
Floor Price ($/Bbl)	$ 70.00	$ —	$ 80.00	$ 80.00	$ —
Ceiling Price ($/Bbl)	$ 80.00	$ —	$ 100.25	$ 100.25	$ —
Total:					
Notional Volume (Bbls)	136,100	443,250	393,450	342,025	209,875

Calls were sold or options provided to counterparties under swaption agreements 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 September 30, 2010, we had debt outstanding of $170.9 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 $0.2 million increase in annual interest expense after consideration of the interest rate swaps discussed below.

We enter into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates. The Company records changes in the fair value of its interest rate derivatives in current earnings under 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 is being 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 September 30, 2010 (in thousands):

Period:	Notional Amount	Fixed Libor Rates
October 1, 2010 to December 18, 2010	$ 10,000	1.50%
October 1, 2010 to December 20, 2010	$ 10,000	1.85%
October 1, 2010 to March 31, 2011	$ 20,000	2.08%
October 1, 2010 to December 10, 2012	$ 20,000	3.35%
October 1, 2010 to January 31, 2013	$ 20,000	2.38%
October 1, 2010 to January 31, 2013	$ 20,000	2.66%
August 6, 2012 to August 6, 2014	$ 25,000	2.09%
August 6, 2012 to August 5, 2015 (1)	$ 30,000	2.25%

(1) The counterparty has the option to extend the termination date of this contract to August 5, 2018.

Counterparty Risk

At September 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)	Credit Agricole (AA-)	Total
Current Assets	$ 6,643	$ 11,632	$ 1,935	$ 1,077	$ 45	$ —	$ 21,332
Current Liabilities	(23)	—	(81)	(236)	—	—	(340)
Long-Term Assets	1,198	—	—	—	—	—	1,198
Long-Term Liabilities	—	(3,081)	(1,863)	(420)	(144)	(251)	(5,759)
Total Amount Due from/(Owed To) Counterparty at September 30, 2010	$ 7,818	$ 8,551	$ (9)	$ 421	$ (99)	$ (251)	$ 16,431

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 September 30, 2010 to provide reasonable assurance that information required to be disclosed by us in our reports that we file or submit under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to management, including the principal executive and principal financial officer, as appropriate to allow timely decisions regarding required disclosure 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

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.

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

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. Moreover, the adoption of legislation requiring the reporting and public disclosure of chemicals used in the fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect ground water. Any such added regulation or public disclosure 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 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 has actively considered and almost one-half of the states have adopted legislation that seeks to control or 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.

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 or to make distributions. 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

None.

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)
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: November 5, 2010

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