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

Form 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2009
OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 001-33756

Vanguard Natural Resources, LLC

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**61-1521161**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
7700 San Felipe, Suite 485 Houston, Texas	**77063**
(Address of Principal Executive Offices)	*(Zip Code)*

Telephone Number: (832) 327-2255

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

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

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

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

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

Common units outstanding on July 30, 2009: 12,145,873.

VANGUARD NATURAL RESOURCES, LLC
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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
Btu	= British thermal unit	MMcf	=million cubic feet

When we refer to natural gas and oil in “equivalents,” we are doing so to compare quantities of 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 one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Revenues:				
Natural gas and oil sales	$ 9,404	$ 20,852	$ 18,606	$ 34,854
Gain (loss) on commodity cash flow hedges	(378)	155	(1,274)	571
Gain (loss) on other commodity derivative contracts	(6,137)	(58,045)	11,512	(79,817)
Total revenues	2,889	(37,038)	28,844	(44,392)
Costs and expenses:				
Lease operating expenses	2,778	2,300	5,911	4,315
Depreciation, depletion, amortization, and accretion	2,645	3,330	6,428	6,154
Impairment of natural gas and oil properties	—	—	63,818	—
Selling, general and administrative expenses	2,941	1,637	6,093	3,283
Production and other taxes	921	1,429	1,563	2,395
Total costs and expenses	9,285	8,696	83,813	16,147
Loss from operations	(6,396)	(45,734)	(54,969)	(60,539)
Other income and (expense):				
Interest income	—	4	—	12
Interest expense	(979)	(1,244)	(1,992)	(2,374)
Gain (loss) on interest rate derivative contracts	607	(46)	228	(51)
Total other expense	(372)	(1,286)	(1,764)	(2,413)
Net loss	$ (6,768)	$ (47,020)	$ (56,733)	$ (62,952)
Net loss per unit:				
Common & Class B units – basic	$ (0.54)	$ (4.19)	$ (4.51)	$ (5.61)
Common & Class B units – diluted	$ (0.54)	$ (4.19)	$ (4.51)	$ (5.61)
Weighted average units outstanding:				
Common units – basic & diluted	12,145,873	10,795,000	12,145,873	10,795,000
Class B units – basic & diluted	420,000	420,000	420,000	420,000

See accompanying notes to consolidated financial statements

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

	June 30, 2009 (Unaudited)	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 3,715	$ 3
Trade accounts receivable, net	4,563	6,083
Derivative assets	21,538	22,184
Other receivables	3,160	2,763
Other current assets	691	845
Total current assets	33,667	31,878
Natural gas and oil properties, at cost	287,389	284,447
Accumulated depletion	(172,303)	(102,178)
Natural gas and oil properties evaluated, net – full cost method	115,086	182,269
Other assets		
Derivative assets	10,824	15,749
Deferred financing costs	709	882
Other assets	1,015	1,784
Total assets	$ 161,301	$ 232,562
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 427	$ 2,148
Accounts payable – natural gas and oil	1,113	1,327
Payables to affiliates	829	2,555
Derivative liabilities	156	486
Accrued expenses	3,673	1,248
Total current liabilities	6,198	7,764
Long-term debt	132,500	135,000
Derivative liabilities	1,682	2,313
Asset retirement obligations	2,185	2,134
Total liabilities	142,565	147,211
Commitments and contingencies		
Members' equity		
Members' capital, 12,145,873 common units issued and outstanding at June 30, 2009 and December 31, 2008	19,513	88,550
Class B units, 420,000 issued and outstanding at June 30, 2009 and December 31, 2008	5,784	4,606
Accumulated other comprehensive loss	(6,561)	(7,805)
Total members' equity	18,736	85,351
Total liabilities and members' equity	$ 161,301	$ 232,562

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating activities		
Net loss	$ (56,733)	$ (62,952)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	6,428	6,154
Impairment of natural gas and oil properties	63,818	—
Amortization of deferred financing costs	202	173
Unit-based compensation	4,015	1,896
Amortization of premiums paid and non-cash settlements on derivative contracts	2,572	2,531
Unrealized losses on other commodity and interest rate derivative contracts	3,310	72,396
Changes in operating assets and liabilities:		
Trade accounts receivable	1,521	(6,453)
Other receivables	(398)	—
Payables to affiliates	(1,726)	615
Other current assets	267	(223)
Price risk management activities, net	(30)	(443)
Accounts payable	(1,934)	669
Accrued expenses	173	3,159
Other assets	(25)	—
Net cash provided by operating activities	21,460	17,522
Investing activities		
Additions to property and equipment	(9)	(62)
Additions to natural gas and oil properties	(1,912)	(6,678)
Acquisitions of natural gas and oil properties	(218)	(66,390)
Deposits and prepayments of natural gas and oil properties	(42)	48
Net cash used in investing activities	(2,181)	(73,082)
Financing activities		
Proceeds from borrowings	10,500	74,400
Repayment of debt	(13,000)	(9,300)
Distributions to members	(12,566)	(8,254)
Financing costs	(177)	(259)
Purchase of units for issuance as unit-based compensation	(324)	(236)
Net cash provided by (used in) financing activities	(15,567)	56,351
Net increase (decrease) in cash and cash equivalents	3,712	791
Cash and cash equivalents, beginning of period	3	3,110
Cash and cash equivalents, end of period	$ 3,715	$ 3,901
Supplemental cash flow information:		
Cash paid for interest	$ 1,892	$ 1,802
Non-cash financing and investing activities:		
Asset retirement obligations	$ —	$ 1,310
Derivative liabilities assumed in acquisition of natural gas and oil properties	$ —	$ 1,128
Transfer of deposit for natural gas and oil properties	$ —	$ 7,830
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 LOSS
(Unaudited)
(in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net loss	$ (6,768)	$ (47,020)	$ (56,733)	$ (62,952)
Net gains (losses) from derivative contracts:				
Unrealized mark-to-market gains arising during the period	—	1,257	—	2,747
Reclassification adjustments for settlements	357	(155)	1,244	(571)
Other comprehensive income	357	1,102	1,244	2,176
Comprehensive loss	$ (6,411)	$ (45,918)	$ (55,489)	$ (60,776)

See accompanying notes to consolidated financial statements

Description of the Business:

Vanguard Natural Resources, LLC is 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, and in south Texas.

References in this report to (1) "us," "we," "our," "the Company," "Vanguard" or "VNR" are to Vanguard Natural Resources, LLC and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC ("TEC"), VNR Holdings, Inc. ("VNRH"), Ariana Energy, LLC ("Ariana Energy"), Vanguard Permian, LLC ("Vanguard Permian") and VNR Finance Corp. ("VNRF") and (2) "Vanguard Predecessor," "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, all of our gathering and compression assets, and all employees other than our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer. Vinland operates all of our existing wells in Appalachia and all of the wells that we drill in Appalachia. We refer to these events as the "Restructuring."

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, 2008, from the audited financial statements filed in our 2008 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 2008 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 loss, members' equity, or net cash flows.

As of June 30, 2009, our significant accounting policies are consistent with those discussed in Note 1 of our consolidated financial statements contained in our 2008 Annual Report on Form 10-K.

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

The consolidated financial statements as of June 30, 2009 and December 31, 2008 and for the three and six months ended June 30, 2009 and 2008 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:

On January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157 "*Fair Value Measurements*" ("SFAS 157") as it relates to financial assets and financial liabilities. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. FAS 157-2, "*Effective Date of FASB Statement No. 157*" ("FSP 157-2"), which delayed the effective date of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on at least an annual basis, until January 1, 2009 for calendar year-end entities. Also in February 2008, the FASB issued FASB Staff Position No. FAS 157-1, *"Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13"* ("FSP 157-1"), which states that Statement of Financial Accounting Standards No. 13, *"Accounting for Leases,"* ("SFAS 13") and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13 are excluded from the provisions of SFAS 157, except for assets and liabilities related to leases assumed in a business combination that are required to be measured at fair value under Statement of Financial Accounting Standards No. 141, *"Business Combinations,"* ("SFAS 141") or Statement of Financial Accounting Standards No. 141 (revised 2007), *"Business Combinations,"* ("SFAS 141(R)"). In October 2008, the FASB issued FASB Staff Position No. FAS 157-3, *"Determining the Fair value of a Financial Asset in a Market That Is Not Active"* ("FSP 157-3"), which clarifies the application of SFAS 157 when the market of a financial asset is inactive and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. The guidance in FSP 157-3 was effective immediately upon issuance and had no impact on our consolidated financial statements.

SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The provisions of this standard apply to other accounting pronouncements that require or permit fair value measurements and are to be applied prospectively with limited exceptions. In adopting SFAS 157 on January 1, 2008, as it relates to financial assets and financial liabilities, 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. The adoption of SFAS 157 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. See Note 5. *Fair Value Measurements* for further discussion.

In April 2009, the FASB issued FASB Staff Position No. FAS 157-4, *"Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly"* ("FSP 157-4"). FSP 157-4 provides additional guidance on estimating fair value when the volume and level of activity for an asset or liability have significantly decreased in relation to normal activity for the asset or liability. FSP 157-4 also provides additional guidance on circumstances that may indicate that a transaction is not orderly. FSP 157-4 is effective for interim and annual periods ending after June 15, 2009. We adopted FSP-157-4 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *"Business Combinations"* ("SFAS 141(R)"), which replaces SFAS No. 141 *"Business Combinations"* ("SFAS 141.") SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity's fiscal year that begins after December 15, 2008. Effective January 1, 2009, we adopted SFAS 141(R). However, since we did not consummate any business combinations during the six months ended June 30, 2009, the adoption did not affect our consolidated financial statements.

In April 2009, the FASB issued FASB Staff Position No. FAS 141(R)-1, *"Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies."* This Staff Position amends the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination under SFAS No. 141(R.) This Staff Position carries forward the requirements in SFAS 141 for acquired contingencies, which would require that such contingencies be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with SFAS No. 5, *"Accounting for Contingencies."* This Staff Position has the same effective date as SFAS 141(R), and the adoption did not affect our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *"Non-controlling Interests in Consolidated Financial Statements—an amendment of ARB No. 51"* ("SFAS 160"). SFAS 160 requires that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. Effective January 1, 2009, we adopted SFAS 160; however, since we do not own any "non-controlling interests," the adoption did not affect our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "*Disclosures about Derivative Instruments and Hedging Activities" ("*SFAS 161"). SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity's financial position, financial performance, and cash flows. SFAS 161 achieves these improvements by requiring disclosure of the fair values of derivative instruments and their gains and losses in a tabular format. It also provides more information about an entity's liquidity by requiring disclosure of derivative features that are credit risk-related. Finally, it requires cross-referencing within footnotes to enable financial statement users to locate important information about derivative instruments. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Effective January 1, 2009, we adopted SFAS 161. The adoption did not have a material impact on our consolidated financial statements. See Note 4. *Price Risk Management Activities* for further discussion.

In May 2008, the FASB issued SFAS No. 162, *"The Hierarchy of Generally Accepted Accounting Principles"* ("SFAS 162"). This statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements in conformity with GAAP in the United States. This statement became effective on November 15, 2008. The adoption of SFAS 162 did not have a material effect on our consolidated financial statements.

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1, *"Interim Disclosures About Fair Value of Financial Instruments"* ("FSP 107-1.") FSP 107-1 amends SFAS No. 107, *"Disclosures about Fair Values of Financial Instruments"* and Accounting Principles Board Opinion No. 28, *"Interim Financial Reporting,"* to require disclosures about fair value of financial instruments in interim financial statements. FSP 107-1 is effective for interim periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted FSP-107-1 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In May 2009, the FASB issued SFAS No. 165, "*Subsequent Events*" ("SFAS 165"). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this Statement sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. In accordance with SFAS 165, an entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. We adopted SFAS 165 effective June 30, 2009 and the adoption did not have a material impact on our financial statements. The date through which subsequent events have been evaluated is July 31, 2009, the date on which the financial statements were issued. See Note 10. *Subsequent Events* for further discussion.

(c) New Pronouncements Issued But Not Yet Adopted:

In December 2008, the Securities and Exchange Commission ("SEC") published a Final Rule, "*Modernization of Oil and Gas Reporting."* The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor, (2) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit, and (3) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We have not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on our disclosures, financial position, or results of operations.

In June 2009, the FASB issued SFAS No. 166, "*Accounting for Transfers of Financial Assets - An Amendment of FASB Statement No. 140*" ("SFAS 166"). SFAS 166 improves the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. The Board undertook this project to address (1) practices that have developed since the issuance of FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, that are not consistent with the original intent and key requirements of that Statement and (2) concerns of financial statement users that many of the financial assets (and related obligations) that have been derecognized should continue to be reported in the financial statements of transferors. SFAS 166 must be applied as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS 166 must be applied to transfers occurring on or after the effective date. SFAS 166 will be effective for us on January 1, 2010. We do not anticipate consummating any transfers of financial assets; therefore, we do not anticipate SFAS 166 having any impact on our consolidated financial statements.

In June 2009, the FASB issued SFAS No. 167, "*Amendments to FASB Interpretation No. 46(R)*" ("SFAS 167"). SFAS 167 improves financial reporting by enterprises involved with variable interest entities. The Board undertook this project to address (1) the effects on certain provisions of FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, as a result of the elimination of the qualifying special-purpose entity concept in SFAS 166, and (2) constituent concerns about the application of certain key provisions of Interpretation 46(R), including those in which the accounting and disclosures under the Interpretation do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. SFAS 167 shall be effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS 167 will be effective for us on January 1, 2010. We do not have any interests in variable interest entities; therefore, we do not anticipate SFAS 167 having any impact on our consolidated financial statements.

In June 2009, the *FASB* issued SFAS No. 168, *"The FASB Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162*" ("SFAS 168"). The FASB *Accounting Standards Codification ™*, ("Codification") will become the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of SFAS 168, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We will adopt the requirements of SFAS 168 in the third quarter of fiscal 2009.

(d) ***Use of Estimates:***

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas 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 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 December 21, 2007, we entered into a Purchase and Sale Agreement with the Apache Corporation for the purchase of certain oil and natural gas properties located in ten separate fields in the Permian Basin of west Texas and southeastern New Mexico. The purchase price for said assets was $78.3 million with an effective date of October 1, 2007. We completed this acquisition on January 31, 2008 for an adjusted purchase price of $73.4 million, subject to customary post closing adjustments. The post closing adjustments reduced the final purchase price to $71.5 million and included a purchase price adjustment of $6.8 million for the cash flow from the acquired properties for the period between the effective date, October 1, 2007, and the final settlement date. As part of this acquisition, we assumed fixed-price oil swaps covering approximately 90% of the estimated proved developed producing oil reserves through 2011 at a weighted average price of $87.29. The fair value of these fixed-price oil swaps was a liability of $1.1 million at January 31, 2008. This acquisition was funded with borrowings under our existing reserve-based credit facility.

On July 18, 2008, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd., a wholly owned subsidiary of the Lewis Energy Group, for the acquisition of certain natural gas and oil properties located in the Dos Hermanos Field in Webb County, Texas. The purchase price for said assets was $53.4 million with an effective date of June 1, 2008. We completed this acquisition on July 28, 2008 for an adjusted purchase price of $51.4 million, subject to customary post-closing adjustments to be determined. This acquisition was funded with $30.0 million of borrowings under our reserve-based credit facility and through the issuance of 1,350,873 common units of the Company valued at $21.4 million. Upon closing this transaction, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from existing producing wells in the acquired properties for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008.

The following unaudited pro forma results for the three and six months ended June 30, 2008 show the effect on our consolidated results of operations as if the January 2008 acquisition and July 2008 acquisition had occurred on January 1, 2008. The pro forma results for the 2008 periods presented are 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 purchase method of accounting, (3) interest expense on added borrowings necessary to finance the acquisition, and (4) the impact of common units issued to partially finance the July 2008 acquisition. The pro forma information is based upon numerous assumptions, and is not necessarily indicative of future results of operations:

	Proforma (in thousands, except per unit data) (unaudited)	
	Three Months Ended June 30, 2008	Six Months Ended June 30, 2008
Total revenues	$ (34,285)	$ (36,985)
Net loss	$ (46,022)	$ (60,305)
Net loss per unit:		
Common & Class B units – basic	$ (3.66)	$ (4.80)
Common & Class B units – diluted	$ (3.66)	$ (4.80)

On July 17, 2009, we entered into a Purchase and Sale agreement to acquire certain natural gas and oil properties in South Texas. See Note 10. *Subsequent Events* for further discussion.

3. Credit Facility and Long-Term Debt

Our credit facility and long-term debt consisted of the following:

			Amount Outstanding (in thousands)	
Description	Interest Rate	Maturity Date	June 30, 2009	December 31, 2008
Senior secured reserve-based credit facility	Variable	March 31, 2011	$ 132,500	$ 135,000

Senior Secured Reserve-Based Credit Facility

In January 2007, we entered into a four-year revolving credit facility ("reserve-based credit facility") with Citibank, N.A. and BNP Paribas. All of our Predecessor's outstanding debt was repaid with borrowings under this reserve-based credit facility. 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 independent petroleum engineers) of estimated future net cash flows from certain of our proved natural gas and oil reserves. The reserve-based credit facility is secured by a first lien security interest in all of our natural gas and oil properties. Additional borrowings were made in January 2008 pursuant to the acquisition of natural gas and oil properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserved-based credit facility was amended in response to a potential acquisition that, ultimately, did not occur. As a result, none of the provisions included in this amendment went into effect. In October 2008, we amended our reserve-based credit facility, which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, our reserve-based credit facility was amended to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which set the allowed interest rate swap hedge percentage at 85% of the outstanding principal balance of indebtedness for the period June 26, 2009 to June 25, 2010. Following this period, the percentage will return to 75%. Our indebtedness under the reserve-based credit facility totaled $132.5 million at June 30, 2009.

Interest rates under the reserve-based credit facility are based on Eurodollar (LIBOR) or ABR (Prime) indications, plus a margin. At June 30, 2009 the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Percentage	***≤33%***	***>33% <66%***	***≥66% <85%***	***≥85%***
Eurodollar Loans	1.500%	1.750%	2.000%	2.125%
ABR Loans	0.000%	0.250%	0.500%	0.750%
Commitment Fee Rate	0.250%	0.300%	0.375%	0.375%
Letter of Credit Fee	1.000%	1.250%	1.500%	1.750%

Our reserve-based credit facility contains a number of customary covenants that require us to maintain certain financial ratios, limit our ability to incur additional debt, sell assets, create liens, or make distributions to our unitholders when our outstanding borrowings exceed 90% of our borrowing base. At June 30, 2009, we were in compliance with our debt covenants.

The Credit Agreement required us to enter into a commodity price hedge position establishing certain minimum fixed prices for anticipated future production equal to approximately 84% of our projected production from proved developed producing reserves from the second half of 2007 through 2011. Also, the Credit Agreement required that certain production put option contracts for the years 2007, 2008, and 2009 be put in place to create a price floor for anticipated production from new wells drilled. See Note 4. *Price Risk Management Activities* for further discussion.

4. Price 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, and 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. 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. The collars and put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub or Houston Ship Channel.

Under Statement of Financial Accounting Standards No. 133 "*Accounting for Derivative Instruments and Hedging Activities*" ("SFAS 133"), 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. The unrealized gains (losses) on derivative contracts that do not qualify for hedge accounting treatment are recorded as gains (losses) on other commodity derivative contracts or gains (losses) on interest rate derivative contracts in the consolidated statements of operations.

In February 2008, as part of the Permian Basin acquisition, we assumed fixed-price oil swaps covering approximately 90% of the estimated proved developed producing oil production through 2011 at a weighted average price of $87.29. Also, in February 2008, we sold calls (or set a ceiling price) which effectively collared 2,000,000 MMBtu of gas production in 2008 through 2009 which was previously only subject to a put (or price floor), we reset the price on 2,387,640 MMBtu of natural gas swaps settling in 2010 from $7.53 to $8.76 per MMBtu, and we entered into a 2012 fixed-price oil swap at $80.00 for 87% of our estimated proved developed production. In April 2008, we reset the price on 800,000 MMBtu of natural gas puts settling from May 1, 2008 to December 31, 2008 from $7.50 to $9.00 per MMBtu at a cost to us of $0.3 million which was funded with cash on hand. In July 2008, in connection with the south Texas acquisition, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from our existing producing wells for the period beginning July 2008 through December 2011.

In February 2009, we liquidated our 2012 oil swap and entered into new 2010 and 2011 natural gas swap and collar transactions. Specifically, a fixed price NYMEX natural gas swap for January through September 2010 and April through September 2011 at $8.04 and $7.85, respectively, was executed for 2,000 MMBtu/day. In addition, a 2,000 MMBtu/day NYMEX natural gas collar with a floor price of $7.50 and a ceiling price of $9.00 for October 2010 through March 2011 and October 2011 through December 2011 was executed. These natural gas derivatives were obtained at prices above the current market by using the proceeds of the liquidation of the 2012 oil swap.

As of June 30, 2009, we have open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		Oil	
Contract Period	MMBtu	Weighted Average Fixed Price	Bbls	WTI Price
July 1, 2009 - December 31, 2009	1,756,188	$ 9.32	89,000	$ 87.23
January 1, 2010 - December 31, 2010	3,782,040	$ 8.95	164,250	$ 85.65
January 1, 2011 - December 31, 2011	3,328,312	$ 7.83	151,250	$ 85.50

Put Option Contracts

Contract Period	Volume in MMBtu	Purchased NYMEX Price Floor
July 1, 2009 - December 31, 2009	396,265	$ 7.50

Collars

	Gas			Oil		
	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
Production Period:						
July 1, 2009 - December 31, 2009	499,998	$ 7.50	$ 9.00	18,400	$ 100.00	$ 127.00
January 1, 2010 - December 31, 2010	914,000	$ 7.90	$ 9.24	—	$ —	$ —
January 1, 2011 - December 31, 2011	364,000	$ 7.50	$ 9.00	—	$ —	$ —

Interest Rate Swaps

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

From December 2007 through March 2008, we entered into interest rate swap agreements which effectively fixed the LIBOR rate at 2.66 % to 3.88% on $60.0 million of borrowings. In August 2008, we entered into two interest rate basis swaps which changed the reset option from three month LIBOR to one month LIBOR on the total $60.0 million of outstanding interest rate swaps. By doing so, we reduced our borrowing cost based on three month LIBOR by 14 basis points on $20.0 million of borrowings for a one year period starting September 10, 2008 and 12 basis points on $40.0 million of borrowings for a one year period starting October 31, 2008. As a result of these two basis swaps, we chose to de-designate the interest rate swaps as cash flow hedges as the terms of the new contracts no longer matched the terms of the original contracts, thus causing the interest rate hedges to be ineffective. Beginning in the third quarter of 2008, we recorded changes in the fair value of our interest rate derivatives in current earnings under gains (losses) on interest rate derivative contracts. The net unrealized gain at June 30, 2008 related to the de-designated cash flow hedges is reported in accumulated other comprehensive income and later reclassified to earnings in the month in which the transactions settle. In December 2008, we amended three existing interest rate swap agreements and entered into one new agreement which fixed the LIBOR rate at 1.85% on $10.0 million of borrowings through December 2010. The first amended agreement reduced the fixed LIBOR rate from 3.88% to 3.35% on $20.0 million and the maturity was extended two additional years to December 10, 2012. In addition, the second amended agreement reset the notional amount on the March 31, 2011 swap from $10.0 million to $20.0 million and also reduced the rate from 2.66% to 2.08%. The third amended agreement reset the notional amount on the January 31, 2011 swap from $10.0 million to $20.0 million, reduced the rate from 3.00% to 2.38% and also extended the maturity two additional years to 2013.

As of June 30, 2009, we have open interest rate derivative contracts as follows:

		Notional Amount (in thousands)	Fixed Libor Rates
Period:			
July 1, 2009 to December 10, 2010	$	10,000	1.50 %
July 1, 2009 to December 20, 2010	$	10,000	1.85 %
July 1, 2009 to January 31, 2011	$	20,000	3.00 %
July 1, 2009 to March 31, 2011	$	20,000	2.08 %
July 1, 2009 to December 10, 2012	$	20,000	3.35 %
July 1, 2009 to January 31, 2013	$	20,000	2.38 %
July 1, 2009 to September 10, 2009 (Basis Swap)	$	20,000	LIBOR 1M vs. LIBOR 3M
July 1, 2009 to October 31, 2009 (Basis Swap)	$	40,000	LIBOR 1M vs. LIBOR 3M

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.

	June 30, 2009	December 31, 2008
	(in thousands)	
Assets:		
Commodity derivatives	$ 36,262	$ 39,875
Interest rate swaps	7	—
	$ 36,269	$ 39,875
Liabilities:		
Commodity derivatives	$ (3,900)	$ (1,942)
Interest rate swaps	(1,845)	(2,799)
	$ (5,745)	$ (4,741)

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 $36.3 million at June 30, 2009.

We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments only with counterparties that are also lenders in our reserve-based credit facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated as of June 30, 2009.

Gain (Loss) on Derivatives

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Realized gains (losses):				
Other commodity derivatives	$ 7,964	$ (5,859)	$ 15,784	$ (7,421)
Interest rate swaps	(398)	(46)	(734)	(51)
	$ 7,566	$ (5,905)	$ 15,050	$ (7,472)
Unrealized gains (losses):				
Other commodity derivatives	$ (14,101)	$ (52,186)	$ (4,272)	$ (72,396)
Interest rate swaps	1,005	—	962	—
	$ (13,096)	$ (52,186)	$ (3,310)	$ (72,396)
Total gains (losses):				
Other commodity derivatives	$ (6,137)	$ (58,045)	$ 11,512	$ (79,817)
Interest rate swaps	607	(46)	228	(51)
	$ (5,530)	$ (58,091)	$ 11,740	$ (79,868)

5. Fair Value Measurements

As discussed in Note 1. Summary of Significant Accounting Policies (b), we adopted SFAS 157 for financial assets and financial liabilities as of January 1, 2008 and for non-financial assets and liabilities as of January 1, 2009. SFAS 157 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 SFAS 157. Primarily, SFAS 157 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 SEC rules. SFAS 157 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, 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 SFAS 157 to assets and liabilities measured at fair value on a recurring basis. This includes natural gas, oil and interest rate derivatives contracts. SFAS 157 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 SFAS 157, 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.

SFAS 157 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. SFAS 157 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 SFAS 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. Our commodity derivative instruments consist of swaps and options. We estimate the fair values of the swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate. We estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties' and our credit standing are used to discount future cash flows. We have classified the fair values of all its derivative contracts as Level 2.

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

	June 30, 2009 (in thousands)			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity price derivative contracts	$ —	$ 32,362	$ —	$ 32,362
Total derivative instruments	$ —	$ 32,362	$ —	$ 32,362
Liabilities:				
Interest rate derivative contracts	$ —	$ (1,838)	$ —	$ (1,838)
Total derivative instruments	$ —	$ (1,838)	$ —	$ (1,838)

On January 1, 2009, we adopted the previously-deferred provisions of SFAS 157 for nonfinancial assets and liabilities, which are comprised primarily of asset retirement costs and obligations initially measured at fair value in accordance with SFAS No. 143, *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). 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 SFAS 143. During the six months ended June 30, 2009, we did not incur asset retirement obligations. The adoption of SFAS 157 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, did not have a material impact on our financial position or results of operations.

6. Asset Retirement Obligations

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

	2009	2008
	(in thousands)	
Asset retirement obligations at January 1,	$ 2,134	$ 190
Liabilities added during the current period	—	1,310
Accretion expense	51	33
Asset retirement obligation at June 30,	$ 2,185	$ 1,533

7. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. Pursuant to amended agreements effective March 1, 2009, we reimburse Vinland $95 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. Also, Vinland receives a fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. This transportation fee 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 under a Gathering and Compression Agreement ("GCA") with Vinland and are reflected in our lease operating expenses. Costs incurred under the MSA were $0.5 million and $0.1 million for the three months ended June 30, 2009 and 2008 and $0.7 million and $0.3 million for the six months ended June 30, 2009 and 2008, respectively. Costs incurred under the GCA were $0.3 million for each of the three months ended June 30, 2009 and 2008 and $0.5 million and $0.5 million, respectively, for the six months ended June 30, 2009 and 2008. A payable of $0.8 million and $2.6 million, respectively, is reflected on our June 30, 2009 and December 31, 2008 consolidated balance sheets in connection with these agreements and direct expenses incurred by Vinland related to the drilling of new wells and operations of all of our existing wells in Appalachia.

On April 1, 2009, we and our wholly-owned subsidiary, TEC, exchanged several wells and lease interests (the "Asset Exchange") with Vinland, Appalachian Royalty Trust, LLC, and Nami Resources Company, L.L.C. (collectively, the "Nami Companies"). Each of the Nami Companies is beneficially owned by Majeed S. Nami, who, as of June 30, 2009, beneficially owned 26.8% 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 per Unit

Basic earnings per unit is computed in accordance with SFAS No. 128, *"Earnings Per Share"* ("SFAS 128") by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during the period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. As of June 30, 2009, we have two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on 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 and no forfeiture is expected; therefore, all Class B units were considered in the computation of basic earnings per unit. The 175,000 options granted to officers under our long-term incentive plan had no dilutive effect as the exercise price is higher than the market price; therefore, they have been excluded from the computation of diluted earnings per unit. In addition, the phantom units granted to officers under our long-term incentive plan will have no dilutive effect unless there is a liability at December 31, 2009 and it is satisfied in units; therefore, they have been excluded from the computation of diluted earnings per unit.

In accordance with SFAS 128, dual presentation of basic and diluted earnings per unit has been presented in the consolidated statements of operations for the three and six months ended June 30, 2009 and 2008 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 vest 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 will vest after three years. The remaining 40,000 restricted Class B units are available to be awarded to new employees or members of our board of directors as they are retained.

In October 2007 and February 2008, four board members were granted 5,000 common units each of which vested after one year. Additionally, in October 2007, two officers were granted options to purchase an aggregate of 175,000 units under our long-term incentive plan with an exercise price equal to the initial public offering price of $19.00 which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant.

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 and the amount paid in either cash or units will equal the appreciation in value of the units, if any, from the date of the grant until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. As of June 30, 2009, a liability and non-cash compensation expense totaling $2.3 million has been recognized.

Furthermore, on January 7, 2009, four board members were granted 5,000 common units each of which will vest after one year and on February 27, 2009, employees were granted 17,950 units which will vest after one year.

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 SFAS No. 123(R), *Share-Based Payment.* The fair value of restricted units issued is determined based on the fair market value of common units on the date of the grant. This value is amortized over the vesting period as referenced above. A summary of the status of the non-vested units as of June 30, 2009 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2008	440,000	$ 18.10
Granted	37,950	8.07
Vested	(20,000)	(17.34)
Non-vested units at June 30, 2009	457,950	$ 17.30

At June 30, 2009, there was approximately $0.9 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 0.6 years. Our consolidated statement of operations reflects non-cash compensation of $1.8 million and $1.0 million in the selling, general and administrative line item for the three months ended June 30, 2009 and 2008 and $4.0 million and $1.9 million for the six months ended June 30, 2009 and 2008, respectively.

10. Subsequent Events

On July 17, 2009, we entered into a Purchase and Sale Agreement to acquire certain natural gas and oil properties in South Texas for $52.3 million from an affiliate of Lewis Energy Group, L.P. ("Lewis") and paid a non-refundable deposit of $2.6 million. The properties to be acquired have total estimated proved reserves of 27 Bcfe as of July 1, 2009, of which 94% is natural gas and 70% is proved developed. In the press release and related Form 8-K filed on July 21, 2009, proved developed reserves were disclosed as 74%, however, based on more recent data, the proved developed reserves percentage is 70%. Lewis will operate all of the wells acquired in this transaction. Based on the current net daily production of approximately 5,000 Mcfe, the properties have a reserve to production ratio of approximately 15 years. The acquisition has a July 1, 2009 effective date, is subject to customary closing conditions and purchase price adjustments and is expected to close in the third quarter of 2009. We are evaluating options for financing this acquisition. At closing, we will assume natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010. In the press release and related Form 8-K filed on July 21, 2009, the percentage of the estimated gas production hedged under the natural gas puts and swaps assumed was reported as 67%, however, based on more recent data, the percentage hedged is 61%. 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 a total cost to the Company of $3.1 million which was financed through deferred premiums. Inclusive of the hedges added, approximately 90% of the estimated gas production from existing producing wells in the acquired properties is hedged through 2011. A schedule of the hedges assumed and added is shown below:

Contract Period	Volume (MMBtu)		Price
Put and Swap Agreements Assumed:			
August – December 2009	765,000	$	8.00
January – December 2010	949,000	$	7.50
Collars Added:			
January – December 2010	693,500	$	7.50 - $8.50
January – December 2011	1,569,500	$	7.31 - $8.31(1)

(1) Price is calculated based on weighted average pricing. In the press release and related Form 8-K filed on July 21, 2009, the weighted average pricing was reported as $7.25 - $8.25. The weighted average pricing reflected above is based on more recent data.

We expect that the SEC will soon declare effective the Company’s registration statement filed with the SEC that registers securities of up to $300.0 million of any combination of debt securities, common units and guarantees of debt securities by the Company’s subsidiaries. The proceeds, terms and pricing of any offerings of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that the Company will or could sell any such securities. The Company’s 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 the Company’s securities at prices acceptable to the Company.

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 2008 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 2008 Annual Report on Form 10-K and this Quarterly Report on Form 10-Q, and those set forth from time to time in our filings with the SEC, which are available on our website at www.vnrllc.com and through the SEC's Electronic Data Gathering and Retrieval System ("EDGAR") at http://www.sec.gov.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

Overview

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

We owned working interests in 1,444 gross (958 net) productive wells at June 30, 2009, and our average net production for the twelve months ended December 31, 2008 and for the six months ended June 30, 2009 was 16,206 Mcfe per day and 17,721 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 96,800 gross undeveloped acres surrounding or adjacent to our existing wells located in southeast Kentucky and northeast Tennessee. Furthermore, in south Texas, we own working interest ranging from 45-50% in approximately 5,300 undeveloped acres surrounding our existing wells. Based on internal reserve estimates at June 30, 2009, approximately 28% or 26.8 Bcfe of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Disruption to Functioning of Capital Markets

Multiple events during 2008 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. 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 but, capital markets remain volatile. As evidenced by recent successful equity and debt offerings by our peers, we expect that we could issue debt and equity if needed.

During the first six months of 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $14.49 on June 11, 2009. Also, during the six months ended June 30, 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. Maintaining adequate liquidity may involve the issuance of debt and 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 and selectively deploying capital to improve existing conditions.

Permian Basin Acquisition

On December 21, 2007, we entered in to a Purchase and Sale Agreement with the Apache Corporation for the purchase of certain oil and natural gas properties located in ten separate fields in the Permian Basin of west Texas and southeastern New Mexico. The purchase price for said assets was $78.3 million with an effective date of October 1, 2007. We completed this acquisition on January 31, 2008 for an adjusted purchase price of $73.4 million, subject to customary post closing adjustments. The post closing adjustments reduced the final purchase price to $71.5 million and included a purchase price adjustment of $6.8 million for the cash flow from the acquired properties for the period between the effective date, October 1, 2007, and the final settlement date. This acquisition was funded with borrowings under our reserve-based credit facility. Through this acquisition, we acquired working interests in 390 gross wells (67 net wells), 49 of which we operate. We manage the operations of these assets from two district offices, one in Lovington, New Mexico and the other in Christoval, Texas. Our operating focus will be on maximizing existing production and looking for complementary acquisitions that we can add to this operating platform. At June 30, 2009, based on internal reserve estimates, we own 3.6 million barrels of oil equivalent, 87% of which is oil and 87% of which is proved developed producing.

South Texas Acquisitions

On July 18, 2008, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd., a wholly owned subsidiary of the Lewis Energy Group, L. P. (“Lewis”) for the acquisition of certain natural gas and oil properties located in the Dos Hermanos Field in Webb County, Texas. The purchase price for said assets was $53.4 million with an effective date of June 1, 2008. We completed this acquisition on July 28, 2008 for an adjusted purchase price of $51.4 million, subject to customary post-closing adjustments to be determined. This acquisition was funded with $30.0 million of borrowings under our reserve-based credit facility and through the issuance of 1,350,873 common units of the Company. In this purchase, we acquired an average of a 98% working interest in 91 producing wells and an average 47.5% working interest in approximately 4,705 gross acres with 41 identified proved undeveloped locations. An affiliate of Lewis Energy Group operates all the properties and is contractually obligated to drill seven wells each year from 2009 through 2011 unless mutually agreed not do so. Upon closing this transaction, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from existing producing wells in the acquired properties for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008. At June 30, 2009, based on internal reserve estimates, we own 20.5 Bcfe of proved reserves, 100% of which is natural gas and 57% of which is proved developed producing.

On July 17, 2009, we entered into a Purchase and Sale Agreement to acquire certain natural gas and oil properties in South Texas for $52.3 million from an affiliate of Lewis and paid a non-refundable deposit of $2.6 million. The properties to be acquired have total estimated proved reserves of 27 Bcfe as of July 1, 2009, of which 94% is natural gas and 70% is proved developed. In the press release and related Form 8-K filed on July 21, 2009, proved developed reserves were disclosed as 74%, however, based on more recent data, the proved developed reserves percentage is 70%. Lewis will operate all of the wells acquired in this transaction. Based on the current net daily production of approximately 5,000 Mcfe, the properties have a reserve to production ratio of approximately 15 years. The acquisition has a July 1, 2009 effective date, is subject to customary closing conditions and purchase price adjustments and is expected to close in the third quarter of 2009. We are evaluating options for financing this acquisition and are currently in the process of amending our existing reserve-based credit facility. As part of the amendment the term of the reserve-based credit facility would be extended and the borrowing base, margins and other fees are expected to increase. At closing, we will assume natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010. In the press release and related Form 8-K filed on July 21, 2009, the percentage of the estimated gas production hedged under the natural gas puts and swaps assumed was reported as 67%, however, based on more recent data, the percentage hedged is 61%. 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 a total cost to the Company of $3.1 million which was financed through deferred premiums. Inclusive of the hedges added, approximately 90% of the estimated gas production from existing producing wells in the acquired properties is hedged through 2011. A schedule of the hedges assumed and added is shown below:

Contract Period	Volume (MMBtu)		Price
Put and Swap Agreements Assumed:			
August – December 2009	765,000	$	8.00
January – December 2010	949,000	$	7.50
Collars Added:			
January – December 2010	693,500	$	7.50 - $8.50
January – December 2011	1,569,500	$	7.31 - $8.31(1)

(1) Price is calculated based on weighted average pricing. In the press release and related Form 8-K filed on July 21, 2009, the weighted average pricing was reported as $7.25 - $8.25. The weighted average pricing reflected above is based on more recent data.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility which is available for our general limited liability company purposes, including, without limitation, capital expenditures and acquisitions. Our obligations under the reserve-based credit facility are secured by substantially all of our assets. Our initial borrowing base under the reserve-based credit facility was set at $115.5 million. However, the borrowing base was subject to $1.0 million reductions per month starting on July 1, 2007 through November 1, 2007, which resulted in a borrowing base of $110.5 million as reaffirmed in November 2007 pursuant to a semi-annual borrowing base redetermination. We applied $80.0 million of the net proceeds from our IPO in October 2007 to reduce our indebtedness under the reserve-based credit facility. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia bank, N.A., and The Bank of Nova Scotia. Additional borrowings were made in January 2008 pursuant to the acquisition of natural gas and oil properties in the Permian Basin, and in July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the south Texas acquisition. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. In October 2008, we amended our reserve-based credit facility which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, a third amendment was entered into which amended covenants to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which set the allowed interest rate swap hedge percentage at 85% of the outstanding principal balance of indebtedness for the period June 26, 2009 to June 25, 2010. Following this period, the percentage will return to 75%. Indebtedness under the reserve-based credit facility totaled $132.5 million at June 30, 2009 and the applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Grid				
Borrowing base utilization percentage	*≤33%*	*>33% <66%*	*≥66% <85%*	*≥85%*
Eurodollar loans	1.500%	1.750%	2.000%	2.125%
ABR loans	0.000%	0.250%	0.500%	0.750%
Commitment fee rate	0.250%	0.300%	0.375%	0.375%
Letter of credit fee	1.000%	1.250%	1.500%	1.750%

We are evaluating options for financing the July 2009 south Texas acquisition and are currently in the process of amending our existing reserve-based credit facility. As part of the amendment the term of the reserve-based credit facility would be extended and the borrowing base, margins and other fees are expected to increase.

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 2008 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. 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 but, capital markets remain volatile. As evidenced by recent successful equity and debt offerings by our peers, we expect that we could issue debt and equity if needed.

Natural gas 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 and our access to capital. As required by our reserve-based credit facility, we have mitigated this volatility for the years 2007 through 2011 by implementing a hedging program on a portion of our proved producing and a portion of our total anticipated production during this time frame.

We face the challenge of natural gas and oil production declines. As a given well's initial reservoir pressures are depleted, natural gas and oil production decreases, thus reducing our total reserves. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will maintain our focus on controlling costs to add reserves through drilling and acquisitions, as well as controlling the corresponding costs necessary to produce such reserves. During the six months ended June 30, 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including the ability to timely obtain drilling permits and regulatory approvals and voluntary reductions in capital spending in a low commodity price environment. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of our production, which may have an adverse effect on our revenues and as a result, cash available for distribution. In accordance with our business plan, we intend to invest the capital necessary to maintain our production at existing levels over the long-term provided that it is economical to do so based on the commodity price environment. However, we cannot be certain that we will be able to issue our debt and 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. The next scheduled redetermination of our borrowing base is October 2009.

Results of Operations

The following table sets forth selected financial and operating data for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009(b)	2008	2009(a)(b)	2008
Revenues:				
Gas sales	$ 5,111	$ 13,307	$ 11,433	$ 22,327
Oil sales	4,293	7,545	7,173	12,527
Natural gas and oil sales	**9,404**	**20,852**	**18,606**	**34,854**
Realized gain (loss) on commodity cash flow hedges	(378)	155	(1,274)	571
Realized gain (loss) on other commodity derivative contracts	7,964	(5,859)	15,784	(7,421)
Unrealized gain (loss) on other commodity derivative contracts	(14,101)	(52,186)	(4,272)	(72,396)
Total revenues	**$ 2,889**	**$ (37,038)**	**$ 28,844**	**$ (44,392)**
Costs and expenses:				
Lease operating expenses	$ 2,778	$ 2,300	$ 5,911	$ 4,315
Depreciation, depletion, amortization, and accretion	2,645	3,330	6,428	6,154
Impairment of natural gas and oil properties	—	—	63,818	—
Selling, general and administrative expenses	2,941	1,637	6,093	3,283
Production and other taxes	921	1,429	1,563	2,395
Total costs and expenses	**$ 9,285**	**$ 8,696**	**$ 83,813**	**$ 16,147**
Other income and (expense):				
Interest expense, net	$ (979)	$ (1,240)	$ (1,992)	$ (2,362)
Realized loss on interest rate derivative contracts	$ (398)	$ (46)	$ (734)	$ (51)
Unrealized gain on interest rate derivative contracts	$ 1,005	$ —	$ 962	$ —

(a) The Permian acquisition closed on January 31, 2008 and, as such, only five months of operations are included in the six month period ended June 30, 2008.

(b) The south Texas acquisition closed on July 28, 2008 and, as such, no operations are included in the three month or six month period ended June 30, 2008.

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008

Revenues

Natural gas and oil sales decreased $11.4 million to $9.4 million during the three months ended June 30, 2009 as compared to the same period in 2008. The key revenue measurements were as follows:

	Three Months Ended June 30, 2009	2008	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	794	903	(12)%
Permian gas (MMcf)	70	109	(36)%
South Texas gas (MMcf)	271	—(a)	N/A
Total natural gas production (MMcf)	1,135	1,012	
Average Appalachian daily gas production (Mcf/day)	8,726	9,922	(12)%
Average Permian daily gas production (Mcf/day)	773	1,202	(36)%
Average south Texas daily gas production (Mcf/day)	2,977	—(a)	N/A
Average Vanguard daily gas production (Mcf/day)	12,476	11,124	
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$ 10.71(b)	$10.35(b)	3%
Net realized gas price, excluding hedges	$ 4.50	$13.14	(66)%
Net Oil Production:			
Appalachian oil (Bbls)	21,186	10,430	103%
Permian oil (Bbls)	56,969	61,817	(8)%
Total oil (Bbls)	78,155	72,247	
Average Appalachian daily oil production (Bbls/day)	233	115	103%
Average Permian daily oil production (Bbls/day)	626	679	(8)%
Average Vanguard daily oil production (Bbls/day)	859	794	
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$ 75.95	$81.01	(6)%
Net realized oil price, excluding hedges	$ 54.93	$104.44	(47)%

(a) The south Texas acquisition closed on July 28, 2008 and, as such, no operations are included in the three month period ended June 30, 2008.
(b) Excludes amortization of premiums paid and non-cash settlements on derivative contracts.

The decrease in natural gas and oil sales during the three months ended June 30, 2009 compared to the same period in 2008 was due primarily to the decreases in commodity prices. In Appalachia, we experienced a 12% decrease in natural gas production which was partially offset by a 103% increase in oil production during the three months ended June 30, 2009 compared to the same period in 2008 for a net production decline of 5% on a Mcfe basis. The 103% increase in Appalachian oil production was primarily due to the focus on the completion of oil zones as oil prices increased during the first three quarters of 2008 which adversely affected the amount of natural gas produced. We experienced a 66% decrease in the average realized natural gas sales price received (excluding hedges) and a 47% decrease in the average realized oil price (excluding hedges). The decrease in commodity prices was partially offset by an 11% increase in our total production on a Mcfe basis. The increase in production for the three months ended June 30, 2009 over the comparable period in 2008 was primarily attributable to the impact from the south Texas acquisition completed in July 2008.

Hedging and Price Risk Management Activities

During the three months ended June 30, 2009, we recognized $0.4 million related to losses on commodity cash flow hedges compared to gains of $0.2 million during the same period in 2008. These amounts relate to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. The loss on commodity cash flow hedges for the three months ended June 30, 2009 relates to the amount that settled in 2009 and has been reclassified to earnings from accumulated other comprehensive loss.

During the three months ended June 30, 2009, we recognized $6.1 million related to losses on other commodity derivative contracts compared to losses of $58.0 million during the same period in 2008. The losses on other commodity derivative contracts for the three months ended June 30, 2009 includes a $14.1 million unrealized loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting and a $8.0 million realized gain related to the settlements recognized during the period. The loss on other commodity derivative contracts for the three months ended June 30, 2008 includes a $52.2 million unrealized loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting and a $5.8 million realized loss related to the settlements recognized during the period. The decrease in unrealized losses on other commodity derivative contracts during the three months ended June 30, 2009 compared to the same period in 2008 resulted from the increase in derivative contracts assumed or entered into as a result of the Permian Basin and south Texas acquisitions as well as a decrease in commodity prices. The increase in realized gains on other commodity derivative contracts during the three months ended June 30, 2009 compared to the same period in 2008 also resulted from the decrease in commodity prices which increased the dollar amount of settlements received.

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 historically included a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. This fee was increased to $95 per well per month beginning March 1, 2009 through December 31, 2009 pursuant to an agreement whereunder Vinland has agreed to provide well-tending services on Vanguard owned wells under a turnkey pricing contract. In addition, we historically have paid 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 has been amended for the period beginning March 1, 2009 through December 31, 2009 to provide for a fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. Lease operating expenses increased by $0.5 million to $2.8 million for the three months ended June 30, 2009 as compared to the three months ended June 30, 2008, of which $0.3 million of the increase was related to the inclusion of the south Texas wells in the three months ended June 30, 2009.

Depreciation, depletion, amortization and accretion decreased to approximately $2.6 million for the three months ended June 30, 2009 from approximately $3.3 million for the three months ended June 30, 2008 due primarily to a lower unamortized cost of natural gas and oil properties as a result of the impairment of these properties recorded during the fourth quarter of 2008 and the first three months of 2009.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the three months ended June 30, 2009 increased $1.3 million as compared to the three months ended June 30, 2008 principally due to an increase in non-cash charges. For the three months ended June 30, 2009 and 2008, non-cash compensation charges amounted to $1.8 million and $1.0 million, respectively, related to the grant of restricted Class B units to officers and an employee, the grant of unit options to management, the grant of phantom units to officers and the grant of common units to board members and employees during 2007 through 2009. All other cash selling, general and administrative expenses increased $0.5 million during the three months ended June 30, 2009 as compared to the same period in 2008 principally due to incremental costs associated with the company's growth and acquisitions.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes decreased by $0.5 million for the three months ended June 30, 2009 as compared to the same period in 2008 as a result of decreased revenues.

Interest expense declined slightly to $1.0 million for the three months ended June 30, 2009 compared to $1.2 million for the three months ended June 30, 2008 primarily due to lower interest rates which more than offset the higher average outstanding debt during the three months ended June 30, 2009.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Revenues

Natural gas and oil sales decreased $16.3 million to $18.6 million during the six months ended June 30, 2009 as compared to the same period in 2008. The key revenue measurements were as follows:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	1,599	1,770	(10)%
Permian gas (MMcf)	129	151(a)	(15)%
South Texas gas (MMcf)	547	—(b)	N/A
Total natural gas production (MMcf)	2,275	1,921	
Average Appalachian daily gas production (Mcf/day)	8,837	9,724	(9)%
Average Permian daily gas production (Mcf/day)	716	1,000(a)	(28)%
Average south Texas daily gas production (Mcf/day)	3,019	—(b)	N/A
Average Vanguard daily gas production (Mcf/day)	12,572	10,724	
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$ 10.68(c)	$10.41(c)	3%
Net realized gas price, excluding hedges	$ 5.02	$11.62	(57)%
Net Oil Production:			
Appalachian oil (Bbls)	37,697	21,421	76%
Permian oil (Bbls)	117,649	102,539(a)	15%
Total oil (Bbls)	155,346	123,960	
Average Appalachian daily oil production (Bbls/day)	208	118	76%
Average Permian daily oil production (Bbls/day)	650	679(a)	(4)%
Average Vanguard daily oil production (Bbls/day)	858	797	
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$ 73.26	$84.61	(13)%
Net realized oil price, excluding hedges	$ 46.18	$101.61	(55)%

(a) The Permian acquisition closed on January 31, 2008 and, as such, only five months of operations are included in the six month period ended June 30, 2008.

(b) The south Texas acquisition closed on July 28, 2008 and, as such, no operations are included in the six month period ended June 30, 2008.

(c) Excludes amortization of premiums paid and non-cash settlements on derivative contracts.

The decrease in natural gas and oil sales during the six months ended June 30, 2009 compared to the same period in 2008 was due primarily to the decreases in commodity prices. In Appalachia, we experienced a 10% decrease in natural gas production which was partially offset by a 76% increase in oil production during the six months ended June 30, 2009 compared to the same period in 2008 for a net production decline of 4% on a Mcfe basis. The 76% increase in Appalachian oil production was primarily due to the focus on the completion of oil zones as oil prices increased during the first three quarters of 2008 which adversely affected the amount of natural gas produced. We experienced a 57% decrease in the average realized natural gas sales price received (excluding hedges) and a 55% decrease in the average realized oil price (excluding hedges). The decrease in commodity prices was partially offset by a 20% increase in our total production on a Mcfe basis. The increase in production for the six months ended June 30, 2009 over the comparable period in 2008 was primarily attributable to the impact from the Permian Basin acquisition completed in January 2008 and the south Texas acquisition completed in July 2008.

Hedging and Price Risk Management Activities

During the six months ended June 30, 2009, we recognized $1.3 million related to losses on commodity cash flow hedges compared to gains of $0.6 million during the same period in 2008. These amounts relate to derivative contracts that we entered into in order to mitigate commodity price exposure on a portion of our expected production and designated as cash flow hedges. The loss on commodity cash flow hedges for the six months ended June 30, 2009 relates to the amount that settled in 2009 and has been reclassified to earnings from accumulated other comprehensive loss.

During the six months ended June 30, 2009, we recognized $11.5 million related to gains on other commodity derivative contracts compared to losses of $79.8 million during the same period in 2008. The gains on other commodity derivative contracts for the six months ended June 30, 2009 includes a $4.3 million unrealized loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting and a $15.8 million realized gain related to the settlements recognized during the period. The loss on other commodity derivative contracts for the six months ended June 30, 2008 includes a $72.4 million unrealized loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting and a $7.4 million realized loss related to the settlements recognized during the period. The decrease in unrealized losses on other commodity derivative contracts during the six months ended June 30, 2009 compared to the same period in 2008 resulted from the increase in derivative contracts assumed or entered into as a result of the Permian Basin and south Texas acquisitions as well as a decrease in commodity prices. The increase in realized gains on other commodity derivative contracts during the six months ended June 30, 2009 compared to the same period in 2008 also resulted from the decrease in commodity prices which increased the dollar amount of settlements received.

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 historically included a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. This fee was increased to $95 per well per month beginning March 1, 2009 through December 31, 2009 pursuant to an agreement whereunder Vinland has agreed to provide well-tending services on Vanguard owned wells under a turnkey pricing contract. In addition, we historically have paid 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 has been amended for the period beginning March 1, 2009 through December 31, 2009 to provide for a fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per mcf margin. Lease operating expenses increased by $1.6 million to $5.9 million for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008, of which $1.3 million of the increase was related to the inclusion of the Permian and south Texas wells for the entire six months in 2009.

Depreciation, depletion, amortization, and accretion increased to approximately $6.4 million for the six months ended June 30, 2009 from approximately $6.2 million for the six months ended June 30, 2008 due primarily to additional depletion recorded on natural gas and oil properties acquired in the Permian Basin and south Texas acquisitions, offset by a lower unamortized cost of natural gas and oil properties as a result of the impairment of these properties recorded during the fourth quarter of 2008 and the first three months of 2009.

An impairment of natural gas and oil properties in the amount of $63.8 million was recognized during the six months ended June 30, 2009 as the unamortized cost of natural gas and oil properties exceeded the sum of the estimated future net revenues from proved properties using period-end prices, discounted at 10% and the lower of cost or fair value of unproved properties as a result of a decline in natural gas prices at the measurement date, March 31, 2009. 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.

Selling, general and administrative expenses include the costs of our administrative employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. These expenses for the six months ended June 30, 2009 increased $2.8 million as compared to the six months ended June 30, 2008 principally due to an increase in non-cash charges. For the six months ended June 30, 2009 and 2008, non-cash compensation charges amounted to $4.0 million and $1.9 million, respectively, related to the grant of restricted Class B units to officers and an employee, the grant of unit options to management, the grant of phantom units to officers and the grant of common units to board members and employees during 2007 through 2009. All other cash selling, general and administrative expenses increased $0.7 million during the six months ended June 30, 2009 as compared to the same period in 2008 principally due to incremental costs associated with the company's growth and acquisitions.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes decreased by $0.8 million for the six months ended June 30, 2009 as compared to the same period in 2008 as a result of decreased revenues.

Interest expense declined slightly to $2.0 million for the six months ended June 30, 2009 compared to $2.4 million for the six months ended June 30, 2008 primarily due to lower interest rates which more than offset the higher average outstanding debt during the six months ended June 30, 2009.

Critical Accounting Policies and Estimates

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

As of June 30, 2009, our critical accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2008.

Recently Adopted Accounting Pronouncements

On January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157 "*Fair Value Measurements*" ("SFAS 157") as it relates to financial assets and financial liabilities. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position No. FAS 157-2, "*Effective Date of FASB Statement No. 157*" ("FSP 157-2"), which delayed the effective date of SFAS 157 for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on at least an annual basis, until January 1, 2009 for calendar year-end entities. Also in February 2008, the FASB issued FASB Staff Position No. FAS 157-1, *"Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13"* ("FSP 157-1"), which states that Statement of Financial Accounting Standards No. 13, *"Accounting for Leases,"* ("SFAS 13") and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13 are excluded from the provisions of SFAS 157, except for assets and liabilities related to leases assumed in a business combination that are required to be measured at fair value under Statement of Financial Accounting Standards No. 141, *"Business Combinations,"* ("SFAS 141") or Statement of Financial Accounting Standards No. 141 (revised 2007), *"Business Combinations,"* ("SFAS 141(R)"). In October 2008, the FASB issued FASB Staff Position No. FAS 157-3, *"Determining the Fair value of a Financial Asset in a Market That Is Not Active"* ("FSP 157-3"), which clarifies the application of SFAS 157 when the market of a financial asset is inactive and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. The guidance in FSP 157-3 was effective immediately upon issuance and had no impact on our consolidated financial statements.

SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The provisions of this standard apply to other accounting pronouncements that require or permit fair value measurements and are to be applied prospectively with limited exceptions. In adopting SFAS 157 on January 1, 2008, as it relates to financial assets and financial liabilities, 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. The adoption of SFAS 157 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. See Note 5 in Part 1—Item 1—Notes to Consolidated Financial Statements for further discussion.

In April 2009, the FASB issued FASB Staff Position No. FAS 157-4, *"Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly"* ("FSP 157-4"). FSP 157-4 provides additional guidance on estimating fair value when the volume and level of activity for an asset or liability have significantly decreased in relation to normal activity for the asset or liability. FSP 157-4 also provides additional guidance on circumstances that may indicate that a transaction is not orderly. FSP 157-4 is effective for interim and annual periods ending after June 15, 2009. We adopted FSP-157-4 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *"Business Combinations"* ("SFAS 141(R)"), which replaces SFAS No. 141 *"Business Combinations"* ("SFAS 141.") SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity's fiscal year that begins after December 15, 2008. Effective January 1, 2009, we adopted SFAS 141(R). However, since we did not consummate any business combinations during the six months ended June 30, 2009, the adoption did not affect our consolidated financial statements.

In April 2009, the FASB issued FASB Staff Position No. FAS 141(R)-1, *"Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies."* This Staff Position amends the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination under SFAS No. 141(R.) This Staff Position carries forward the requirements in SFAS 141 for acquired contingencies, which would require that such contingencies be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with SFAS No. 5, *"Accounting for Contingencies."* This Staff Position has the same effective date as SFAS 141(R), and the adoption did not affect our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, *"Non-controlling Interests in Consolidated Financial Statements—an amendment of ARB No. 51"* ("SFAS 160"). SFAS 160 requires that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. Effective January 1, 2009, we adopted SFAS 160; however, since we do not own any "non-controlling interests," the adoption did not affect our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "*Disclosures about Derivative Instruments and Hedging Activities" ("*SFAS 161"). SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity's financial position, financial performance, and cash flows. SFAS 161 achieves these improvements by requiring disclosure of the fair values of derivative instruments and their gains and losses in a tabular format. It also provides more information about an entity's liquidity by requiring disclosure of derivative features that are credit risk-related. Finally, it requires cross-referencing within footnotes to enable financial statement users to locate important information about derivative instruments. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Effective January 1, 2009, we adopted SFAS 161. The adoption did not have a material impact on our consolidated financial statements. See Note 4 in Part 1—Item 1—Notes to Consolidated Financial Statements for further discussion.

In May 2008, the FASB issued SFAS No. 162, *"The Hierarchy of Generally Accepted Accounting Principles"* ("SFAS 162"). This statement identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements in conformity with GAAP in the United States. This statement became effective on November 15, 2008. The adoption of SFAS 162 did not have a material effect on our consolidated financial statements.

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1*, "Interim Disclosures About Fair Value of Financial Instruments"* ("FSP 107-1.") FSP 107-1 amends SFAS No. 107, *"Disclosures about Fair Values of Financial Instruments"* and Accounting Principles Board Opinion No. 28, *"Interim Financial Reporting,"* to require disclosures about fair value of financial instruments in interim financial statements. FSP 107-1 is effective for interim periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted FSP-107-1 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In May 2009, the FASB issued SFAS No. 165, "*Subsequent Events*" ("SFAS 165"). SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this Statement sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. In accordance with SFAS 165, an entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. We adopted SFAS 165 effective June 30, 2009 and the adoption did not have a material impact on our financial statements. The date through which subsequent events have been evaluated is July 31, 2009, the date on which the financial statements were issued. See Note 10 in Part 1—Item 1—Notes to Consolidated Financial Statements for discussion of subsequent events.

New Pronouncements Issued But Not Yet Adopted

In December 2008, the Securities and Exchange Commission ("SEC") published a Final Rule, "*Modernization of Oil and Gas Reporting.*" The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserves volumes. The new requirements also will allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor, (2) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit, and (3) report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices. The use of average prices will affect future impairment and depletion calculations. The new disclosure requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We have not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on our disclosures, financial position, or results of operations.

In June 2009, the FASB issued SFAS No. 166, "*Accounting for Transfers of Financial Assets - An Amendment of FASB Statement No. 140*" ("SFAS 166"). SFAS 166 improves the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. The Board undertook this project to address (1) practices that have developed since the issuance of FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* , that are not consistent with the original intent and key requirements of that Statement and (2) concerns of financial statement users that many of the financial assets (and related obligations) that have been derecognized should continue to be reported in the financial statements of transferors. SFAS 166 must be applied as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS 166 must be applied to transfers occurring on or after the effective date. SFAS 166 will be effective for us on January 1, 2010. We do not anticipate consummating any transfers of financial assets; therefore, we do not anticipate SFAS 166 having any impact on our consolidated financial statements.

In June 2009, the FASB issued SFAS No. 167, "*Amendments to FASB Interpretation No. 46(R)*" ("SFAS 167"). SFAS 167 improves financial reporting by enterprises involved with variable interest entities. The Board undertook this project to address (1) the effects on certain provisions of FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, as a result of the elimination of the qualifying special-purpose entity concept in SFAS 166, and (2) constituent concerns about the application of certain key provisions of Interpretation 46(R), including those in which the accounting and disclosures under the Interpretation do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. SFAS 167 shall be effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS 167 will be effective for us on January 1, 2010. We do not have any interests in variable interest entities; therefore, we do not anticipate SFAS 167 having any impact on our consolidated financial statements.

In June 2009, the *FASB* issued SFAS No. 168, *"The FASB Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162*" ("SFAS 168"). The FASB *Accounting Standards Codification ™*, ("Codification") will become the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of SFAS 168, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We will adopt the requirements of SFAS 168 in the third quarter of fiscal 2009.

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 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 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 2008 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. 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 but, capital markets remain volatile. As evidenced by recent successful equity and debt offerings by our peers, we expect that we could issue debt and equity if needed. During the six months ended June 30, 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. The benefits expected to accrue to our unitholders from our expansion activities may be muted by substantial cost of capital increases during this period.

Natural gas 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 NYMEX crude oil spot price per barrel for the period between January 1, 2009 and June 30, 2009 ranged from a high of $72.69 to a low of $34.03 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2009 to June 30, 2009 ranged from a high of $6.07 to a low of $3.25. As of July 30, 2009, the NYMEX crude oil spot price per barrel was $66.94 and the NYMEX natural gas spot price per MMBtu was $3.74.

Overview

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and 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, depending on market conditions. As of July 30, 2009, we have $25.0 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value (as determined by independent petroleum engineers) of estimated future net cash flows (utilizing the bank's internal projection of future natural gas and oil prices) from our proved natural gas and oil reserves. Based on the current commodity price environment, banks have lowered their internal projections of future natural gas and oil prices which has decreased the borrowing base and thus decreased the amount available to be borrowed under our reserve-based credit facility. In May 2009, our borrowing base was reduced from $175.0 million to $154.0 million. If commodity prices continue to decline and banks continue to lower their internal projections of natural gas and oil prices, it is possible that we will be subject to additional 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. As a result, 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 remainder of 2009 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. We are currently in the process of amending our existing reserve-based credit facility. As part of the amendment, the term of the reserve-based credit facility would be extended and the borrowing base, margins and other fees are expected to increase.

Cash Flow from Operations

Net cash provided by operating activities for the six months ended June 30, 2009 was $21.5 million, compared to $17.5 million for the six months ended June 30, 2008. The increase in cash provided by operating activities during the six months ended June 30, 2009 was substantially due to increased income, after adjusting for non-cash items, offset by a $2.2 million net decrease in operating assets and liabilities. The increased income during the six months ended June 30, 2009, was largely a result of increased hedged production associated with the Permian and south Texas acquisitions.

Cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas and oil prices. Natural gas and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather, and other factors beyond our control. Future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, as well as the prices received for production. We enter into derivative contracts to reduce the impact of commodity price volatility on operations. Currently, we use a combination of fixed-price swaps and NYMEX collars and put options to reduce our exposure to the volatility in natural gas 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.

Cash Flow from Investing Activities

Cash used in investing activities was approximately $2.2 million for the six months ended June 30, 2009, compared to $73.1 million for the six months ended June 30, 2008. The decrease in cash used in investing activities was primarily attributable to $66.4 million used for the acquisition of natural gas and oil properties in the Permian Basin during the six months ended June 30, 2008. In addition, the total for the six months ended June 30, 2009 includes $1.9 million for the drilling and development of natural gas and oil properties as compared to $6.7 million for the six months ended June 30, 2008.

Cash Flow from Financing Activities

Cash used in financing activities was approximately $15.6 million for the six months ended June 30, 2009, compared to cash provided by financing activities of $56.4 million for the six months ended June 30, 2008. During the six months ended June 30, 2009, total net repayments under our reserve-based credit facility were $2.5 million and $12.6 million was used for distributions to unitholders compared to $8.3 million in distribution to unitholders in the comparable period in 2008. During the six months ended June 30, 2008, total proceeds from borrowings under our reserve-based credit facility were $74.4 million, which were principally used to fund the Permian Basin acquisition.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. Our reserve-based credit facility was amended and restated in February 2008 to extend the maturity date from January 2011 to March 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and the Bank of Nova Scotia. The increase in the borrowing base was principally the result of inclusion of the reserves related to the Permian Basin acquisition in January 2008. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. As of October 22, 2008, our reserve-based credit facility was amended to increase the borrowing base to $175.0 million and add one lender, BBVA Compass Bank. The increase in the borrowing base was principally the result of inclusion of the reserves related to the south Texas acquisition in July 2008. In February 2009, a third amendment was entered into which amended covenants to allow the company 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 set the allowed interest rate swap hedge percentage at 85% of the outstanding principal balance of indebtedness for the period June 26, 2009 to June 25, 2010. Following this period, the percentage will return to 75%. At June 30, 2009, we had $132.5 million outstanding under our reserve-based credit facility and as of July 30, 2009, we have $25.0 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value (as determined by independent petroleum engineers) of estimated future net cash flows (utilizing the bank's internal projection of future natural gas and oil prices) from our proved natural gas and oil reserves. Based on the current commodity price environment, banks have lowered their internal projections of future natural gas and oil prices which has decreased the borrowing base and thus decreased the amount available to be borrowed under our reserve-based credit facility. In May 2009, our borrowing base was reduced from $175.0 million to $154.0 million. If commodity prices continue to decline and banks continue to lower their internal projections of natural gas and oil prices, it is possible that we will be subject to additional 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. As a result, 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 remainder of 2009 to reduce our borrowings under our reserve-based credit facility. We are currently in the process of amending our existing reserve-based credit facility. As part of the amendment, the term of the reserve-based credit facility would be extended and the borrowing base, margins and other fees are expected to increase.

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 1.50% and 2.125% per annum; or
- a domestic bank rate plus an applicable margin between 0.00% and 0.75% per annum.

As of June 30, 2009, we have elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

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

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

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

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, 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 SFAS 133, which includes the current portion of derivative contracts; and
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures of not more than 4.0 to 1.0.

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

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

- failure to pay any principal when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect when made;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $2.0 million, or any event occurs that permits or causes the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or our subsidiaries;
- the entry of, and failure to pay, one or more adverse judgments in excess of $1.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal;
- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $1.0 million in any year; and
- a change of control, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Securities Exchange Act of 1934 and the rules of the Securities Exchange Commission) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests other than by Majeed S. Nami or his affiliates, or (2) the replacement of a majority of our directors by persons not approved by our board of directors.

Off-Balance Sheet Arrangements

At June 30, 2009, we did not have any off-balance sheet arrangements that have, or are reasonably likely to have, an effect on our financial position or results of operations.

Contingencies

We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. As of June 30, 2009, there were no loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of June 30, 2009 is provided in the following table:

	Payments Due by Year (in thousands)						
	2009	2010	2011	2012	2013	After 2013	Total
Management compensation	$ 338	$ 112	$ —	$ —	$ —	$ —	$ 450
Asset retirement obligations	—	38	187	33	14	1,914	2,186
Derivative liabilities	116	3,712	1,227	690	—	—	5,745
Long-term debt (1)	—	—	132,500	—	—	—	132,500
Operating leases	61	31	—	—	—	—	92
Total	$ 515	$ 3,893	$ 133,914	$ 723	$ 14	$ 1,914	$ 140,973

(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 and non-cash settlement on derivative contracts;
- Unrealized gains and losses on other commodity and interest rate derivative contracts;
- Deferred taxes; and
- Unit-based compensation expense.

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

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

For the three months ended June 30, 2009 as compared to the three months ended June 30, 2008, Adjusted EBITDA increased 11%, from $11.9 million to $13.3 million. For the six months ended June 30, 2009 as compared to the six months ended June 30, 2008, Adjusted EBITDA increased 16%, from $22.4 million to $25.9 million. The following table presents a reconciliation of consolidated net loss to Adjusted EBITDA:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net loss	$ (6,768)	$ (47,020)	$ (56,733)	$ (62,952)
Plus:				
Interest expense, including realized losses on interest rate derivative contracts	1,377	1,244	2,726	2,374
Depreciation, depletion, amortization, and accretion	2,645	3,330	6,428	6,154
Impairment of natural gas and oil properties	—	—	63,818	—
Amortization of premiums paid and non-cash settlements on derivative contracts	1,107	1,230	2,572	2,531
Unrealized losses on other commodity and interest rate derivative contracts	13,096	52,186	3,310	72,396
Deferred taxes	(4)	—	(201)	—
Unit-based compensation expense	1,827	981	4,015	1,896
Less:				
Interest income	—	4	—	12
Adjusted EBITDA	$ 13,280	$ 11,947	$ 25,935	$ 22,387

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 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 and oil production. Realized pricing is primarily driven by the Columbia Gas Appalachian Index ("TECO Index"), Henry Hub, and Houston Ship Channel for natural gas production and the West Texas Intermediate Light Sweet for oil production. Pricing for natural gas 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 writedown the carrying value of our natural gas and oil properties increases when oil and gas prices are low or volatile. In addition, writedowns may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase. For example, natural gas prices declined throughout the first three months of 2009. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the three months ended March 31, 2009 of $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. No ceiling test impairment was necessary for the three months ended June 30, 2009.

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 have put options for which we pay the counterparty the fair value at the purchase date. At the settlement date we receive the excess, if any, of the fixed floor over the floating rate. 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 price on a notional quantity. 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.

At June 30, 2009, the fair value of commodity derivative contracts was an asset of approximately $32.4 million, of which $21.5 million settles during the next twelve months.

The following table summarizes commodity derivative contracts in place at June 30, 2009:

	July 1, - December 31, 2009	Year 2010	Year 2011
Gas Positions:			
Fixed Price Swaps:			
Notional Volume (MMBtu)	1,756,188	3,782,040	3,328,312
Fixed Price ($/MMBtu)	$ 9.32	$ 8.95	$ 7.83
Puts:			
Notional Volume (MMBtu)	396,265	—	—
Floor Price ($/MMBtu)	$ 7.50	$ —	$ —
Collars:			
Notional Volume (MMBtu)	499,998	914,000	364,000
Floor Price ($/MMBtu)	$ 7.50	$ 7.90	$ 7.50
Ceiling Price ($/MMBtu)	$ 9.00	$ 9.24	$ 9.00
Total:			
Notional Volume (MMBtu)	2,652,451	4,696,040	3,692,312
Oil Positions:			
Fixed Price Swaps:			
Notional Volume (Bbls)	89,000	164,250	151,250
Fixed Price ($/Bbl)	$ 87.23	$ 85.65	$ 85.50
Collars:			
Notional Volume (Bbls)	18,400	—	—
Floor Price ($/Bbl)	$ 100.00	$ —	$ —
Ceiling Price ($/Bbl)	$ 127.00	$ —	$ —
Total:			
Notional Volume (Bbls)	107,400	164,250	151,250

Interest Rate Risks

At June 30, 2009, we had debt outstanding of $132.5 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 $0.3 million increase in annual interest expense after consideration of the interest rate swaps discussed below. We entered into interest rate swaps, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate exposures to fixed interest rates.

In August 2008, we entered into two interest rate basis swaps which changed the reset option from three month LIBOR to one month LIBOR on the total $60.0 million of outstanding interest rate swaps. By doing so, we reduced our borrowing cost based on three month LIBOR by 14 basis points on $20.0 million of borrowings for a one year period starting September 10, 2008 and 12 basis points on $40.0 million of borrowings for a one year period starting October 31, 2008. As a result of these two basis swaps, we chose to de-designate the interest rate swaps as cash flow hedges as the terms of the new contracts no longer matched the terms of the original contracts, thus causing the interest rate hedges to be ineffective. Beginning in the third quarter of 2008, we recorded changes in the fair value of our interest rate derivatives in current earnings under unrealized gains (losses) on interest rate derivative contracts. The net unrealized gain related to the de-designated cash flow hedges is reported in accumulated other comprehensive income and later reclassified to earnings in the month in which the transactions settle. In December 2008, we amended three existing interest rate swap agreements and entered into one new agreement which fixed the LIBOR rate at 1.85% on $10.0 million of borrowings through December 2010. The first amended agreement reduced the fixed LIBOR rate from 3.88% to 3.35% on $20.0 million and the maturity was extended two additional years to December 10, 2012. In addition, the second amended agreement reset the notional amount on the March 31, 2011 swap from $10.0 million to $20.0 million and also reduced the rate from 2.66% to 2.08%. The third amended agreement reset the notional amount on the January 31, 2011 swap from $10.0 million to $20.0 million, reduced the rate from 3.00% to 2.38%, and also extended the maturity two additional years to 2013.

The following summarizes information concerning our positions in open interest rate derivative contracts at June 30, 2009:

	Notional Amount (in thousands)	Fixed Libor Rates
Period:		
July 1, 2009 to December 10, 2010	$ 10,000	1.50%
July 1, 2009 to December 20, 2010	$ 10,000	1.85%
July 1, 2009 to January 31, 2011	$ 20,000	3.00%
July 1, 2009 to March 31, 2011	$ 20,000	2.08%
July 1, 2009 to December 10, 2012	$ 20,000	3.35%
July 1, 2009 to January 31, 2013	$ 20,000	2.38%
July 1, 2009 to September 10, 2009 (Basis Swap)	$ 20,000	LIBOR 1M vs. LIBOR 3M
July 1, 2009 to October 31, 2009 (Basis Swap)	$ 40,000	LIBOR 1M vs. LIBOR 3M

Counterparty Risk

At June 30, 2009, based upon all of our open commodity and interest rate 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-)	Wachovia Bank, N.A. (AA)	Total
Current Asset, net	$ 1,991	$ 19,024	$ 523	$ —	$ 21,538
Current Liability, net	(53)	—	—	(103)	(156)
Long-Term Asset, net	1,739	9,085	—	—	10,824
Long-Term Liability, net	—	(683)	(720)	(279)	(1,682)
Total Amount Due from Counterparty/(Owed to Counterparty) at June 30, 2009	$ 3,677	$ 27,426	$ (197)	$ (382)	$ 30,524

We net derivative assets and liabilities for counterparties where we have a legal right of offset. Our counterparties are participants in our reserve-based credit facility.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report on Form 10-Q, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) was evaluated by our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, in accordance with rules of the Securities Exchange Act of 1934, as amended. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of June 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to management and recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed below or elsewhere in this Form 10-Q or our other SEC filings, could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations. For a detailed discussion of the risk factors that should be understood by any investor contemplating investment in our units, please refer to the section entitled "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2008 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, 2008 other than those set forth below. For further information, see Part I—Item 1A—Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008.

Natural gas and oil prices are volatile. A decline in natural gas and oil prices could adversely affect our credit availability, financial position, financial results, cash flow, access to capital and ability to grow.

Our future borrowing base under our reserve-based credit facility, financial condition, revenues, results of operations, rate of growth and the carrying value of our natural gas and oil properties depend primarily upon the prices we receive for our natural gas and oil production and the prices prevailing from time to time for natural gas and oil. Prices also affect our cash flow available for capital expenditures and our ability to access funds under our reserve-based credit facility and through the capital markets. The amount available for borrowing under our reserve-based credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to semi-annual redeterminations based on pricing models determined by the lenders at such time. The decline in natural gas and oil prices has adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. In May 2009, our borrowing base was reduced from $175.0 million to $154.0 million. It is possible that we will be subject to a further reduction in our borrowing base at our next scheduled redetermination. If our outstanding borrowings under the reserve-based credit facility exceed 90% of our borrowing base, we would be required to cease paying distributions to our unitholders until we reduce our borrowings below the 90% threshold. We are evaluating options for financing the July 2009 south Texas acquisition and are currently in the process of amending our existing reserve-based credit facility. As part of the amendment, the term of the reserve-based credit facility would be extended and the borrowing base, margins and other fees are expected to increase.

Natural gas 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 NYMEX crude oil spot price per barrel for the period between January 1, 2009 and June 30, 2009 ranged from a high of $72.69 to a low of $34.03 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2009 to June 30, 2009 ranged from a high of $6.07 to a low of $3.25. As of July 30, 2009, the NYMEX crude oil spot price per barrel was $66.94 and the NYMEX natural gas spot price per MMBtu was $3.74. This price volatility affects the amount of our cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for natural gas and oil are subject to a variety of factors, including:

- the level of consumer demand for natural gas and oil;
- the domestic and foreign supply of natural gas and oil;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign crude natural gas and oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and to enforce crude oil price and production controls;
- domestic and foreign governmental regulations and taxes;

- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption; and
- worldwide economic conditions.

Declines in natural gas and oil prices would not only reduce our revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations, and reserves. We use the full cost method of accounting for natural gas and oil properties which requires us to perform a ceiling test quarterly that is impacted by declining prices. Significant price declines could cause us to take quarterly writedowns related to the results of such "ceiling tests", which would be reflected as non-cash charges against current earnings. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the three months ended March 31, 2009 of $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. No ceiling test impairment was necessary for the three months ended June 30, 2009. If the gas and oil industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, pay distributions to our unitholders, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can affect the value of our units.

Certain federal income tax deductions currently available with respect to oil and gas drilling and development may be eliminated as a result of future legislation. Additionally, federal income tax rates may be increased for certain investors, in which case any income resulting from an investment in us may result in higher federal income tax payments.

The White House released a preview of its budget for Fiscal Year 2010 on February 26, 2009, entitled "A New Era of Responsibility: Renewing America's Promise." Among the new administration's proposed changes are the outright elimination of many of the key federal income tax benefits historically associated with oil and gas. Although presented in very summary form, among other significant energy tax items, the administration's budget appears to propose the complete elimination of (1) expensing of intangible drilling costs, and (2) the "percentage depletion" method of deduction with respect to oil and gas wells. Additionally, the budget proposes to reinstate for single individuals making greater than $200,000 per year, and for couples making greater than $250,000 per year, the maximum ordinary income rates of 36% and 39.6%, respectively and increase the maximum long-term capital gain rate to 20%. Although no legislation has yet been formally introduced, the administration's apparent effective date would be January 1, 2011. It is unclear whether such proposal will be proposed as actual legislation and, if so, whether it will actually be enacted. In addition, there are other significant tax changes under discussion in the Congress. If this proposal (or others) is enacted into law, it could represent an extremely significant reduction in the tax benefits that have historically applied to certain investments in oil and gas.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACESA. The purpose of ACESA is to control and reduce emissions of "greenhouse gases," or "GHGs," in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth's atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

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

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which 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 groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

The annual meeting of unitholders of Vanguard Natural Resources, LLC was held on May 12, 2009 in Houston, Texas. At the annual meeting, holders of 12,565,873 units were entitled to vote on the specified unitholder matters, of which 10,774,720 units were present and voting, or 86% of the outstanding units, which constituted a quorum.

Proposals submitted to a vote of the unitholders were:

(1) The election of six directors of Vanguard Natural Resources, LLC for a one-year term expiring at the 2010 annual meeting of unitholders and until their respective successors are elected and qualified.

Director’s Name	Number of Voting Units For	Withheld
W. Richard Anderson	10,610,227	164,493
Loren Singletary	10,633,528	141,192
Bruce W. McCullough	10,634,927	139,793
John R. McGoldrick	10,634,927	139,793
Lasse Wagene	10,633,428	141,292
Scott W. Smith	10,634,827	139,893

(2) The ratification of BDO Seidman, LLP as our independent registered public accountants for the fiscal year ended December 31, 2009.

For	Against	Abstained
10,739,534	33,543	1,643

Item 5. Other Information

None.

Item 6. Exhibits

EXHIBIT INDEX

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

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.31	Fourth Amendment to First Amended and Restated Credit Agreement, dated June 26, 2009, by and between Vanguard Natural Gas, LLC, lenders party hereto, and Citibank, N.A., as administrative agent	Filed herewith
10.32	Purchase and Sale Agreement, dated July 17, 2009, among Vanguard Permian, LLC and Segundo Navarro Drilling, Ltd.	Form 8-K, filed July 21, 2009 (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: July 31, 2009

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

Exhibit 10.31

FOURTH AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT

THIS FOURTH AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT is made as ofJune 26, 2009 (the ***"Fourth Amendment to Restated Credit Agreement,"*** or this ***"Amendment"***), among **VANGUARD NATURAL GAS,LLC**, a Kentucky limited liability company (***"Borrower"***), each lender from time to time party hereto (collectively, the ***"Lenders"***), and **CITIBANK, N.A.**, a national banking association, in its capacity as Administrative Agent (***"Administrative Agent"***).

R E C I T A L S

A. Borrower, the Lenders, and the Administrative Agent are parties to that certain First Amended and Restated Credit Agreement dated as of February 14, 2008, and as amended by a First Amendment to First Amended and Restated Credit Agreement dated as of May 15, 2008, and as amended by a Second Amendment to First Amended and Restated Credit Agreement dated as of October 22, 2008, and as amended by a Third Amendment to First Amended and Restated Credit Agreement dated as of February 18, 2009 (collectively, the ***"Original Credit Agreement"***).

B. Borrower has requested certain amendments to the Original Credit Agreement as hereinafter provided.

NOW, THEREFORE, in consideration of these premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

1. **Same Terms**. All terms used herein which are defined in the Original Credit Agreement shall have the same meanings when used herein, unless the context hereof otherwise requires or provides. In addition, all references in the Loan Documents to the "Agreement" shall mean the Original Credit Agreement, as amended by this Amendment, as the same shall hereafter be amended from time to time. In addition, the following terms have the meanings set forth below:

"Effective Date" means June 26, 2009.

"Modification Papers" means this Amendment and all of the other documents and agreements executed in connection with the transactions contemplated by this Amendment.

2. **Conditions Precedent**. The transactions contemplated by this Amendment shall be deemed to be effective as of the Effective Date, when the following conditions have been complied with to the satisfaction of Administrative Agent, unless waived in writing by Administrative Agent:

A. **Fourth Amendment to Restated Credit Agreement**. This Fourth Amendment to Restated Credit Agreement shall be in full force and effect.

B. **Fees and Expenses**. Administrative Agent shall have received payment of all out-of-pocket fees and expenses (including reasonable attorneys' fees and expenses) incurred by Administrative Agent in connection with the preparation, negotiation and execution of the Modification Papers.

C. **Representations and Warranties** All representations and warranties contained herein or in the documents referred to herein or otherwise made in writing in connection herewith or therewith shall be true and correct with the same force and effect as though such representations and warranties have been made on and as of this date.

3. **<u>Amendments to Original Credit Agreement</u>**. On the Effective Date, Section 9.18 of the Original Credit Agreement shall be amended to read in its entirety as follows::

> "The Borrower will not, and will not permit any Subsidiary to, enter into any Swap Agreements with any Person other than (a) Swap Agreements in respect of commodities (i) with an Approved Counterparty and (ii) the notional volumes for which (when aggregated with other commodity Swap Agreements then in effect other than basis differential swaps on volumes already hedged pursuant to other Swap Agreements) do not exceed, as of the date such Swap Agreement is executed, 95% of the reasonably anticipated projected production from proved, developed, producing Oil and Gas Properties for each month during the period during which such Swap Agreement is in effect for each of crude oil and natural gas, calculated separately and (b) Swap Agreements in respect of interest rates with an Approved Counterparty with the purpose and effect of fixing interest rates on a principal amount of indebtedness of the Borrower that is accruing interest at a variable rate, provided that (i) the aggregate notional amount of such contracts never exceeds (A) during the period from June 26, 2009 through June 25, 2010, 85% of the anticipated outstanding principal balance of the indebtedness to be hedged by such contracts or an average of such principal balances calculated by using a generally accepted method of matching interest swap contracts to declining principal balances, and (B) thereafter, 75% of the anticipated outstanding principal balance of the indebtedness to be hedged by such contracts or an average of such principal balances calculated by using a generally accepted method of matching interest swap contracts to declining principal balances, and (ii) the floating rate index of each such contract generally matches the index used to determine the floating rates of interest on the corresponding indebtedness to be hedged by such contract, and (c) Swap Agreements required by <u>Section 8.16</u>. In no event shall any Swap Agreement contain any requirement, agreement or covenant for the Borrower or any Subsidiary to post collateral (other than Letters of Credit) or margin to secure their obligations under such Swap Agreement or to cover market exposures."

4. **<u>Certain Representations</u>**. Borrower represents and warrants that, as of the Effective Date: (a) Borrower has full power and authority to execute the Modification Papers, and the Modification Papers executed by Borrower constitute the legal, valid and binding obligation of Borrower enforceable in accordance with their terms, except as enforceability may be limited by general principles of equity and applicable bankruptcy, insolvency, reorganization, moratorium, and other similar laws affecting the enforcement of creditors' rights generally; and (b) no authorization, approval, consent or other action by, notice to, or filing with, any governmental authority or other person is required for the execution, delivery and performance by Borrower thereof. In addition, Borrower represents that all representations and warranties contained in the Original Credit Agreement are true and correct in all material respects on and as of the Effective Date (except representations and warranties that relate to a specific prior date are based upon the state of facts as they exist as of such date).

5. **<u>No Further Amendments</u>**. Except as previously amended in writing or as amended hereby, the Original Credit Agreement shall remain unchanged and all provisions shall remain fully effective among the parties.

6. **<u>Limitation on Agreements</u>**. The modifications set forth herein are limited precisely as written and shall not be deemed (a) to be a consent under or a waiver of or an amendment to any other term or condition in the Original Credit Agreement or any of the Loan Documents, or (b) to prejudice any right or rights which Administrative Agent and/or the Lenders now have or may have in the future under or in connection with the Original Credit Agreement and the Loan Documents, each as amended hereby, or any of the other documents referred to herein or therein. The Modification Papers shall constitute Loan Documents for all purposes.

7. **Counterparts**. This Amendment may be executed in any number of counterparts, each of which when executed and delivered shall be deemed an original, but all of which constitute one instrument. In making proof of this Amendment, it shall not be necessary to produce or account for more than one counterpart thereof signed by each of the parties hereto.

8. **Incorporation of Certain Provisions by Reference**. The provisions of Section 12.09 of the Original Credit Agreement captioned "Governing Law; Jurisdiction; Consent to Service of Process; Waiver of Jury Trial" are incorporated herein by reference for all purposes.

9. **Entirety, Etc**. This instrument and all of the other Loan Documents embody the entire agreement between the parties. THIS AMENDMENT AND ALL OF THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

[This space is left intentionally blank. Signature pages follow.]

IN WITNESS WHEREOF, the parties hereto have executed this Amendment to be effective as of the date and year first above written.

BORROWER: **VANGUARD NATURAL GAS, LLC**

By: /s/ Richard Robert
Richard Robert
Executive Vice President and Chief Financial Officer

ADMINISTRATIVE AGENT: **CITIBANK, N.A.**
as Administrative Agent

By: /s/ Ryan Watson
Ryan Watson
Vice President

LENDERS: **CITIBANK, N.A.**

By: /s/ Ryan Watson
Ryan Watson
Vice President

LENDERS: **BNP PARIBAS**

By: /s/ Brian M. Malone
Name: Brian M. Malone
Title: Managing Director

By: /s/ Betsy Jocher
Name: Betsy Jocher
Title: Director

LENDERS: **THE BANK OF NOVA SCOTIA**

By: /s/ David G. Mills
Name: David G. Mills
Title: Managing Director

LENDERS: **COMPASS BANK**

By: /s/ Kathleen J. Bowen
Name: Kathleen J. Bowen
Title: Senior Vice President

LENDERS: **WACHOVIA BANK, NATIONAL ASSOCIATION**

By: /s/ Shawn Young
Name: Shawn Young
Title: Director

EXHIBIT 31.1

CERTIFICATION

I, Scott W. Smith, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: July 31, 2009

/s/ Scott W. Smith

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

EXHIBIT 31.2

CERTIFICATION

I, Richard A. Robert, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: July 31, 2009

/s/ Richard A. Robert

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

EXHIBIT 32.1

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

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott W. Smith, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Scott W. Smith

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

July 31, 2009

EXHIBIT 32.2

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

In connection with the accompanying Quarterly Report of Vanguard Natural Resources, LLC (the "Company") on Form 10-Q for the period ended June 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard A. Robert, Executive Vice-President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

July 31, 2009