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

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2008

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
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Units	NYSE Arca, Inc.

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if 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 ☒

The aggregate market value of Vanguard Natural Resources, LLC common units held by non-affiliates of the registrant as of June 30, 2008 was approximately $121,851,750 based upon the New York Stock Exchange composite transaction closing price.

As of March 5, 2009, 12,145,873 of the registrant's common units remained outstanding.

Documents Incorporated by Reference:

Portions of the registrant's proxy statement to be furnished to unitholders in connection with its 2009 Annual Meeting of Unitholders are incorporated by reference in Part III, Items 10-14 of this annual report on Form 10-K for the year ending December 31, 2008 ("this Annual Report").

Vanguard Natural Resources, LLC

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Forward Looking Statements

The statements contained in this report, other than statements of historical fact, constitute forward-looking statements. Such statements include, without limitation, all statements as to the production of oil and gas, product prices, oil and gas reserves, drilling and completion results, capital expenditures and other such matters. These statements relate to events and/or future financial performance and involve known and unknown risks, uncertainties and other factors that may cause our actual results, levels of activity, performance or achievements or the industry in which we operate to be materially different from any future results, levels of activity, performance or achievements expressed or implied by the forward-looking statements. These risks and other factors include those listed under Item 1A "Risk Factors" and those described elsewhere in this report.

In some cases, you can identify forward-looking statements by our use of terms such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "intends," "predicts," "potential" or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In evaluating these statements, you should specifically consider various factors, including the risks outlined under "Risk Factors." These factors may cause our actual results to differ materially from any forward-looking statement. Factors that could affect our actual results and could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, the following:

- the volatility of realized natural gas and oil prices;
- the conditions of the capital markets, interest rates, availability of credit facilities to support business requirements, liquidity and general economic conditions;
- the discovery, estimation, development and replacement of natural gas and oil reserves;
- our business and financial strategy;
- our drilling locations;
- technology;
- our cash flow, liquidity and financial position;
- our production volumes;
- our operating expenses, general and administrative costs, and finding and development costs;
- the availability of drilling and production equipment, labor and other services;
- our future operating results;
- our prospect development and property acquisitions;
- the marketing of natural gas and oil;
- competition in the natural gas and oil industry;
- the impact of weather and the occurrence of natural disasters such as fires, floods, hurricanes, earthquakes and other catastrophic events and natural disasters;
- governmental regulation of the natural gas and oil industry;
- environmental regulations;
- developments in oil-producing and natural gas producing countries; and
- our strategic plans, objectives, expectations and intentions for future operations.

Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements. Moreover, neither we nor any other person assumes responsibility for the accuracy and completeness of these forward-looking statements. We do not intend to update any of the forward-looking statements after the date of this report to conform prior statements to actual results.

GLOSSARY OF TERMS

Below is a list of terms that are common to our industry and used throughout this document:

/day	= per day	MBbls	= thousand barrels
Bbls	= barrels	Mcf	= thousand cubic feet
Bcf	= billion cubic feet	Mcfe	= thousand cubic feet of natural gas equivalents
Bcfe	= billion cubic feet equivalents	MMBtu	= million British thermal units
Btu	= British thermal unit	MMcfe	= million cubic feet of natural gas equivalents

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”) and Vanguard Permian, LLC (“Vanguard Permian”) and (2) “Vanguard Predecessor,” “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natural Gas, LLC.

PART I

ITEM 1. BUSINESS

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 completed our initial public offering, or "IPO," on October 29, 2007, and our common units, representing limited liability company interests, are listed on the NYSE Arca, Inc. under the symbol "VNR."

On April 18, 2007 but effective January 5, 2007 our Predecessor was separated into our operating subsidiary and Vinland Energy Eastern, LLC, or "Vinland," an affiliate of Mr. Majeed S. Nami or "Nami," who together with certain of his affiliates and related persons, is our largest unitholder. 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 natural 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, and 100% of our Predecessor's working interest in depths above and 100 feet below our known producing horizons. Vinland acts as the operator of our existing wells in Appalachia and all of the wells that we drill in this area. The separation was effected to facilitate our formation, as we are a company focused on lower risk production, development and acquisition opportunities, while Vinland pursues higher capital intensive development, exploitation and exploration opportunities. Our working interest in any particular well in our drilling program will vary based on the lease or leases on which such well is located and the participation of any minority owners in the drilling of such wells.

On December 21, 2007, we entered in to a Purchase and Sale Agreement with the Apache Corporation for the purchase of certain natural gas and oil properties located in ten separate fields in the Permian Basin of west Texas and southeastern New Mexico, referred to as the "Permian Basin acquisition." 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. With respect to operations, we have established two district offices, one in Lovington, New Mexico and the other in Christoval, Texas to manage these assets. Our operating focus will be on maximizing existing production and looking for complementary acquisitions that we can add to this operating platform. With this acquisition, based on internal reserve estimates, we acquired 4.4 million barrels of oil equivalent, 83% of which is oil and 90% of which is proved developed producing.

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, referred to as the "south Texas acquisition." 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 to do so. Based on internal reserve estimates, we acquired 20 Bcfe of proved reserves, 98% of which is natural gas and 65% of which is proved developed producing. 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 for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008.

Our estimated proved reserves at December 31, 2008 were 108.5 Bcfe, of which approximately 75% were natural gas and 75% were classified as proved developed. At December 31, 2008, we owned working interests in 1,444 gross (958 net) productive wells and our average net production for the year ended December 31, 2008 was 16,206 Mcfe per day. We also have a 40% working interest in approximately 109,500 gross undeveloped acres surrounding or adjacent to our existing wells located in southeast Kentucky and northeast Tennessee. As mentioned above, Vinland owns the remaining 60% working interest in this acreage. Approximately 25%, or

27.6 Bcfe, of our estimated proved reserves as of December 31, 2008 were attributable to this 40% working interest. In addition, we own a contract right to receive approximately 99% of the net proceeds from the sale of production from certain oil and gas wells located in Bell and Knox Counties, Kentucky, which accounted for approximately 2.6% of our estimated proved reserves as of December 31, 2008. Our wells and undeveloped leasehold acreage in Appalachia fall within an approximate 750,000 acre area, which we refer to in this Annual Report as the "area of mutual interest," or AMI. We have agreed with Vinland until January 1, 2012 to offer the other the right to participate in any acquisition, exploitation and development opportunities that arise in the AMI, subject however to Vinland's right to consummate up to two acquisitions with a purchase price of $5.0 million or less annually without a requirement to offer us the right to participate in such acquisitions. In south Texas, we own working interests ranging from 45-50% in approximately 5,300 undeveloped acres surrounding our existing wells.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 18 years based on our proved reserves as of December 31, 2008. During 2008, we drilled 87 gross wells (39 net wells) and as of December 31, 2008, we had identified 352 additional proved undeveloped drilling locations and over 252 other drilling locations on our leasehold acreage. Pursuant to a participation agreement that we have entered into with Vinland, Vinland generally has control over our drilling program in Appalachia and has the sole right to determine which wells are drilled in Appalachia until January 1, 2011. During this period we will meet with Vinland on a quarterly basis to review Vinland's proposal to drill not less than 25 nor more than 40 gross wells, in which we will own a 40% working interest, in any quarter. Up to 20% of the proposed wells may be carried over and added to the wells to be drilled in the subsequent quarter, provided that Vinland is required to drill at least 100 gross wells per calendar year. If Vinland proposes the drilling of less than 25 gross wells in any quarter, we have the right to propose the drilling of up to a total of 14 net wells, in which we will own a 100% working interest, in a given quarterly period. If either party elects not to participate in the drilling of the proposed wells or future operations with respect to drilled wells and such drilling or operations are performed within the calendar quarter, as proposed, such party forfeits all right, title and interest in the natural gas and oil production that may be produced from such wells. Notwithstanding the foregoing, if both parties agree, no drilling is required. We anticipate that, given existing market conditions, neither party will propose or participate in drilling until favorable conditions for drilling exist. The participation agreement will remain in place for four years and shall continue thereafter on a year to year basis until such time as either party elects to terminate the agreement. The obligations of the parties with respect to the drilling program described above will expire in three years, after which we each will have the right to propose the drilling of wells within the AMI and offer participation in such proposed drilling to the other party and if either party elects not to participate in such proposed drilling or future operations with respect to drilled wells, such party forfeits all right, title and interest in the natural gas and oil production that may be produced from such wells.

Disruption to Functioning of Capital Markets

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to raise debt and equity at prices that are similar to offerings in recent years to be limited as long as the capital markets remain constrained.

During 2008, our unit price closed at a high of $18.41 on May 20, 2008 and our unit price declined to a closing low of $4.72 on December 23, 2008, which is the lowest our unit price has closed at since our initial public offering. Since that date our unit price has partially recovered to a level of $8.85 on March 5, 2009. 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 production.

Business Strategies

Our primary business objective is to provide stable cash flows allowing us to make quarterly cash distributions to our unitholders, and over the long-term to increase the amount of our future distributions by executing the following business strategies:

- Manage our natural gas and oil assets with a focus on maintaining production levels and optimizing cash flows by monitoring lease operating costs;

- Replace reserves either through the development of our extensive inventory of proved undeveloped locations or make accretive acquisitions of natural gas and oil properties in the known producing basins of the continental United States characterized by a high percentage of producing reserves, long-life, stable production and step-out development opportunities;

- Maintain a conservative capital structure to ensure financial flexibility for opportunistic acquisitions; and

- Use derivative instruments to reduce the volatility in our revenues resulting from changes in natural gas and oil prices.

Our Relationship with Vinland

General. Nami owns 90% of Vinland, and Nami and certain of his affiliates and related persons own a 26.8% membership interest in us. Vinland's senior management team has extensive experience operating in the Appalachian Basin and has operated our assets on behalf of our Predecessor in southeast Kentucky and northeast Tennessee since 1999. As of December 31, 2008, Vinland operated substantially all of our wells in Appalachia. As of December 31, 2008, Vinland had assets consisting of production from their 60% working interest in new wells drilled in 2007 and 2008, a 60% working interest in approximately 109,500 gross undeveloped acres in the AMI, interests in an additional 125,000 undeveloped acres and certain coalbed methane gas rights located in the Appalachian Basin, the rights to any natural gas and oil located on our acreage at depths above and 100 feet below our known producing horizons and certain gathering and compression assets. Vinland intends to rely on contributions from Nami to fund its proportionate share of our drilling program but Nami has no obligation to make such contributions to Vinland.

Participation Agreement. Pursuant to a participation agreement that we have entered into with Vinland, Vinland has general control over our drilling program in Appalachia and has the sole right to determine which wells are drilled until January 1, 2011. During this period, when favorable conditions for drilling exist, we will meet with Vinland on a quarterly basis to review Vinland's proposal to drill not less than 25 nor more than 40 gross wells, in which we will own a 40% working interest, in any quarter. Up to 20% of the proposed wells may be carried over and added to the wells to be drilled in the subsequent quarter, provided that Vinland is required to drill at least 100 gross wells per calendar year. If Vinland proposes the drilling of less than 25 gross wells in any quarter, we have the right to propose the drilling of up to a total of 14 net wells during such quarter, in which we will own a 100% working interest. If either party elects not to participate in the drilling of the proposed wells or future operations with respect to drilled wells and such drilling or operations are performed within the calendar quarter, as proposed, such party forfeits all right, title and interest in the natural gas and oil production that may be produced from such wells. We anticipate that, given existing market conditions, neither party will propose or participate in drilling until favorable conditions for drilling exist. The participation agreement will remain in place for four years and shall continue thereafter on a year to year basis until such time as either party elects to terminate the agreement. The obligations of the parties with respect to the drilling program described above will expire in three years.

Operation and Development of Assets. Effective as of January 5, 2007, we entered into various agreements with Vinland, under which we rely on Vinland to operate our existing producing wells in Appalachia and coordinate our development drilling program in Appalachia. We expect to benefit from the substantial development and operational expertise of Vinland's management in the Appalachian Basin. Pursuant to the participation agreement that we have entered into with Vinland, Vinland has control over our drilling program in Appalachia and has the sole right to determine which wells are proposed to be drilled in Appalachia.

Under a management services agreement, Vinland will advise and consult with us regarding all aspects of our production and development operations and provide us with administrative support services as necessary for the operation of our business. Vinland may, but does not have any obligation to, provide us with acquisition services under the management services agreement.

Gathering and Compression. Under a gathering and compression agreement that we entered into with Vinland, Vinland gathers, compresses, delivers and provides the services necessary for us to market our natural gas production in the area of mutual interest. Vinland delivers our natural gas production to certain designated interconnects with third-party transporters. We pay Vinland a fee of $0.25 per Mcf, plus our proportionate share of fuel and line loss for producing wells as of January 5, 2007. For all wells drilled after January 5, 2007, we pay Vinland a fee of $0.55 per Mcf, plus our proportionate share of fuel and line loss. The gathering and compression rates will increase by 11% on January 1, 2011, and shall be adjusted annually thereafter based on a published wage index adjustment factor.

We also assumed certain transportation agreements that Vinland had with Delta Natural Gas with respect to volumes of gas produced in Kentucky. Delta receives gas from various interconnects with Vinland and redelivers said volumes to Columbia Gas Transmission. We currently pay Delta $0.27 per MMBtu plus a fuel charge equal to 2% of volume for this transportation service.

In addition, we assumed a right to 7,000 MMBtu/day of firm transportation that Vinland had on the Columbia Gas Transmission system. We currently pay Columbia Gas $0.22 per MMBtu plus a fuel charge equal to 2% of volume for this firm transportation right. This volume was approximately 49% of our total 2007 actual production in Appalachia.

Our relationship with Vinland is a source of potential conflicts. For example, neither Vinland, nor any of its affiliates, is restricted from competing with us. Vinland or its affiliates may acquire or invest in natural gas and oil properties or other assets outside of the area of mutual interest in the future without any obligation to offer us the opportunity to purchase or own interests in those assets.

Natural Gas and Oil Prices

The Appalachian Basin is a mature producing region with well known geologic characteristics. Reserves in the Appalachian Basin typically have a high degree of step-out development success; that is, as development progresses, reserves from newly completed wells are reclassified from the proved undeveloped to the proved developed category and additional adjacent locations are added to proved undeveloped reserves. As a result, the cumulative amount of total proved reserves tends to increase as development progresses.

Wells in the Appalachian Basin generally produce little or no water, contributing to a low cost of operation. In addition, most wells produce dry natural gas, which does not require processing. Natural gas produced in the Appalachian Basin typically sells for a premium to New York Mercantile Exchange, or "NYMEX," natural gas prices due to the proximity to major consuming markets in the northeastern United States. For the year ended December 31, 2008, the average premium over NYMEX for natural gas delivered to our primary delivery points in the Appalachian Basin on the Columbia Gas Transmission system was $0.34 per MMBtu. In addition, most of our natural gas production has historically had a high Btu content, resulting in an additional premium to NYMEX natural gas prices. For the year ended December 31, 2008, our average realized natural gas prices in Appalachia (before hedging), represented a $1.87 per Mcfe premium to NYMEX natural gas prices, which accounts for both the basis differential and the Btu adjustments.

In the Permian Basin, most of our gas production is casinghead gas produced in conjunction with our oil production. Casinghead gas typically has a high Btu content and requires processing prior to sale to third parties. We have a number of processing agreements in place with gatherers/processors of our casinghead gas and we share in the revenues associated with processing, depending on the terms of the various agreements. We expect that the revenues from the sale of casinghead gas plus our share of the revenues from the sale of natural gas liquids will result in a realized price per Mcf of gas produced equal to the NYMEX natural gas price.

In south Texas, our natural gas production has a high Btu content and requires some processing prior to sale to third parties. Through our relationship with the operator of the south Texas properties, Lewis Petro Properties, Inc. ("Lewis"), we benefit from a processing agreement that was in place prior to our acquisition of these natural gas properties. Our proportionate share of the gas volumes are sold at the tailgate of the processing plant at the Houston Ship Channel Index price which typically results in a discount to NYMEX prices; however, with our share of the natural gas liquids associated with the processing of such gas, our revenues on an Mcf basis are a premium to the NYMEX prices.

Our oil production, both in Appalachia and the Permian Basin, is sold under month-to-month sales contracts with purchasers that take delivery of the oil volumes at the tank batteries adjacent to the producing wells. Our pricing for oil sales is based on the monthly average of the West Texas Intermediate Price, or "WTI," as posted for the various regions and published by Plains Marketing, LP, ConocoPhillips or a similar large purchaser of oil, less a transportation or quality differential which corresponds to the field location or type of oil being produced. In Appalachia, we have historically received the average WTI price less $9.93. Since our ownership in 2008 in the Permian Basin, we have received the average WTI price less $3.62.

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of natural gas and oil price volatility on our cash flow from operations. Currently, we use fixed-price swaps and NYMEX collars and put options to hedge natural gas and oil prices. By removing the price volatility from a significant portion of our natural gas and oil production, we have mitigated, but not eliminated, the potential effects of fluctuation in natural gas and oil prices on our cash flow from operations. For a description of our derivative positions, please read "Item 7A—Quantitative and Qualitative Disclosures About Market Risk."

Natural Gas and Oil Data

Proved Reserves

The following table presents our estimated net proved natural gas and oil reserves and the present value of the estimated proved reserves at December 31, 2008, based on a reserve report prepared by Netherland, Sewell & Associates, Inc., or "NSAI." The estimate of net proved reserves has not been filed with or included in reports to any federal authority or agency. The Standardized Measure value shown in the table is not intended to represent the current market value of our estimated natural gas and oil reserves.

	As of December 31, 2008
Reserve Data:	
Estimated net proved reserves:	
Natural gas (Bcf)	81.2
Crude oil (MBbls)	4,547
Total (Bcfe)	108.5
Proved developed (Bcfe)	80.9
Proved undeveloped (Bcfe)	27.6
Proved developed reserves as % of total proved reserves	75%
Standardized measure (in millions) (1)	$ 190.1
Representative Natural Gas and Oil Prices (2)**:**	
Natural gas—Spot Henry Hub per MMBtu	$ 5.71
Oil—WTI per Bbl	$ 41.00

(1) Does not give effect to hedging transactions. For a description of our hedging transactions, please read "Item 7A—Quantitative and Qualitative Disclosures About Market Risk."

(2) Natural gas and oil prices as of period end are based on NYMEX prices per MMBtu and Bbl at such date, with these representative prices adjusted by field to arrive at the appropriate net price.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty or from existing wells on which a relatively major expenditure is required to establish production.

The data in the above table represents estimates only. Natural gas and oil reserve engineering is inherently a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of natural gas and oil that are ultimately recovered. Please read "Item 1A—Risk Factors."

Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

From time to time, we engage NSAI to prepare a reserve and economic evaluation of properties that we are considering purchasing. Neither NSAI nor any of their respective employees has any interest in those properties and the compensation for these engagements is not contingent on their estimates of reserves and future net revenues for the subject properties. During 2008, we paid NSAI approximately $145,000 for all reserve and economic evaluations.

Production and Price History

The following table sets forth information regarding net production of natural gas and oil and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	Vanguard		Vanguard Predecessor
	2008	2007	2006
Net Production:			
Total realized production (MMcfe)	5,931	4,238	4,378
Average daily production (Mcfe/day)	16,206(a)	11,610	11,995
Average Realized Sales Prices ($ per Mcfe):			
Average sales prices (including hedges)	$ 11.43(b)	$ 8.99(b)	$ 8.22
Average sales prices (excluding hedges)	$ 11.61	$ 8.15	$ 8.72
Average Unit Costs ($ per Mcfe):			
Production costs	$ 2.71	$ 1.68	$ 1.52
Selling, general and administrative expenses	$ 1.13(c)	$ 0.83(c)	$ 1.19
Depreciation, depletion, amortization and accretion	$ 2.51	$ 2.12	$ 1.97

(a) Average daily production for 2008 calculated based on 366 days including production for the Permian Basin and south Texas acquisitions from the closing dates of these acquisitions.

(b) Excludes amortization of premiums paid and non-cash settlement on derivative contracts.

(c) Includes $3.6 million ($.60/Mcfe) and $2.1 million ($0.51/Mcfe) of non-cash unit-based compensation expense in 2008 and 2007, respectively.

Productive Wells

The following table sets forth information at December 31, 2008 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas Wells		Oil Wells		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operated	32	30	39	35	71	65
Non-operated	1,006	864	367	29	1,373	893
Total	1,038	894	406	64	1,444	958

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2008 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross (3)	**Net (4)**	**Gross (3)**	**Net (4)**	**Gross**	**Net**
Operated	9,547	6,683	7,653	6,039	17,200	12,722
Non-operated	25,520	22,734	109,491	44,787	135,011	67,521

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Drilling Activity

Most of our wells in Appalachia are relatively shallow, ranging from 2,500 to 4,500 feet, and drill through as many as ten potential producing zones. Many of our wells are completed to multiple producing zones and production from these zones may be commingled. Our average well in Appalachia takes 10 days to drill and most of our wells are producing and connected to a pipeline within 30 days after completion. In general, our producing wells in Appalachia have stable production profiles and long-lived production, often with total projected economic lives in excess of 50 years. Once drilled and completed, operating and maintenance requirements for producing wells in the Appalachian Basin are generally low and only minimal, if any, capital expenditures are required. In 2009, in Appalachia, we and our operating partner, Vinland, plan to focus our efforts on re-completions and operational items that do not require substantial capital investment but will enhance production from existing wells.

In the Permian Basin acquisition, we acquired four development drilling locations. In 2008, we drilled one of these locations with a 100% working interest and participated in two additional wells, offsetting a third party's producing well with a 50% working interest. These projected wells range in depth from 8,000 to 11,000 feet and target multiple producing horizons. These wells are estimated to each cost between $0.7 million to $1.0 million to drill and complete, depending on the total depth targeted.

In the south Texas acquisition, we acquired a 45-50% working interest in 39 identified proved undeveloped locations that we and the operator, Lewis, plan to jointly develop over the next five years. In 2008, we jointly drilled four wells, all of which were successfully completed. In the current commodity price environment, we and Lewis have elected to defer drilling additional development wells until such time as rig and service costs decline to a point where drilling operations will generate acceptable economic returns.

When we resume drilling operations, we intend to concentrate our drilling activity on lower risk, development properties. The number and types of wells we drill will vary depending on the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests we acquire in each well and the estimated recoverable reserves attributable to each well.

The following table sets forth information with respect to wells completed during the years ended December 31, 2008, 2007 and 2006. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of natural gas, regardless of whether they produce a reasonable rate of return.

	Year Ended December 31,		
	Vanguard		Vanguard Predecessor
	2008	2007	2006
Gross wells:			
Productive	86	82	100
Dry	1	1	—
Total	87	83	100
Net Development wells:			
Productive	38	33	96
Dry	1	—	—
Total	39	33	96
Net Exploratory wells:			
Productive	—	—	4
Dry	—	—	—
Total	—	—	4

Operations

Principal Customers

For the year ended December 31, 2008, sales of natural gas and oil to Seminole Energy Services, Osram Sylvania, Inc., BP Energy Company, Plains Marketing L.P. and Sunoco Partners Marketing and Terminals, L.P. accounted for approximately 52%, 15%, 10%, 7% and 4%, respectively, of our natural gas and oil revenues. Our top five purchasers during the year ended December 31, 2008, therefore accounted for 88% of our total revenues. To the extent these and other customers reduce the volumes of natural gas and oil that they purchase from us and they are not replaced in a timely manner with a new customer, our revenues and cash available for distribution could decline. However, if we were to lose a customer, we believe we could identify a substitute purchaser in a timely manner.

Price Risk Management Activities

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 an option premium, equal to the fair value of the option 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. Conditions sometimes arise where actual production is less than estimated, which has, and could result in overhedged volumes. The following table summarizes commodity derivative contracts in place at December 31, 2008:

	2009	2010	2011	2012
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	3,629,946	3,236,040	2,962,312	—
Fixed Price ($/MMBtu)	$ 9.42	$ 9.10	$ 7.82	$ —
Puts:				
Notional Volume (MMBtu)	840,143	—	—	—

Floor Price ($/MMBtu)	$ 7.50	$ —	$ —	$ —
Collars:				
Notional Volume (MMBtu)	1,000,000	730,000	—	—
Floor Price ($/MMBtu)	$ 7.50	$ 8.00	$ —	$ —
Ceiling Price ($/MMBtu)	$ 9.00	$ 9.30	$ —	$ —
Total:				
Notional Volume (MMBtu)	5,470,089	3,966,040	2,962,312	—
Oil Positions:				
Fixed Price Swaps:				
Notional Volume (Bbls)	181,500	164,250	151,250	144,000
Fixed Price ($/Bbl)	$ 87.23	$ 85.65	$ 85.50	$ 80.00
Collars:				
Notional Volume (Bbls)	36,500	—	—	—
Floor Price ($/Bbl)	$ 100.00	$ —	$ —	$ —
Ceiling Price ($/Bbl)	$ 127.00	$ —	$ —	$ —
Total:				
Notional Volume (Bbls)	218,000	164,250	151,250	144,000

In February 2009, we liquidated our 2012 oil swap and entered into new 2010 and 2011 natural gas swap and collar transactions. Specifically, an $8.04 and $7.85 fixed price NYMEX natural gas swap for January through September 2010 and April through September 2011, 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 set at prices above the current market by using the proceeds of the liquidation of the 2012 oil swap.

We have also 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.

The following summarizes information concerning our positions in open interest rate swaps at December 31, 2008.

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

Counterparty Risk

At December 31, 2008, based upon all of our open derivative contracts shown above and their respective mark-to-market values, the Company had the following current and long-term derivative assets and liabilities shown by counterparty with their March 5, 2009 S&P financial strength rating in parentheses:

	Citibank, N.A. (A+)	BNP Paribas (AA)	The Bank of Nova Scotia (AA-)	Wachovia Bank, N.A. (AA+)	Total
Current Assets	$ —	$ 20,636,355	$ 1,547,293	$ —	$ 22,183,648
Current Liabilities	$ (7,800)	$ —	$ —	$ (478,776)	$ (486,576)
Long-Term Assets	$ 212,133	$ 15,536,588	$ —	$ —	$ 15,748,721
Long-Term Liabilities	$ —	$ (1,394,750)	$ (658,599)	$ (259,986)	$ (2,313,335)
Total Amount Due from Counterparty/(Owed to Counterparty) at December 31, 2008	$ 204,333	$ 34,778,193	$ 888,694	$ (738,762)	$ 35,132,458

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

Competition

The natural gas and oil industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, leasing acreage, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staff substantially larger than ours or a different business model. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial, technical or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the natural gas and oil industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development and exploitation program.

Competition is also strong for attractive natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure unitholders that we will be able to compete satisfactorily when attempting to make further acquisitions.

Title to Properties

As is customary in the natural gas and oil industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, however, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We will not commence drilling operations on a property until we have cured any material title defects on such property. Prior to completing an acquisition of producing natural gas and oil leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our natural gas and oil properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the natural gas and oil industry. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, customary royalty interests, contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for taxes not yet payable and other burdens, restrictions and minor encumbrances customary in the natural gas and oil industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties, or will materially interfere with our use of these properties in the operation of our business.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in some of our operating areas, specifically the Appalachian region and, as a result, we generally perform the majority of our drilling in this area during the summer and fall months. These seasonal anomalies can pose challenges for meeting our well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations. Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain natural gas consumers utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Environmental Matters and Regulation

General. Our business involving the acquisition and development of natural gas and oil properties is subject to extensive and stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to conservation and environmental protection. These operations are subject to the same environmental laws and regulations as other similarly situated companies in the natural gas and oil industry. These laws and regulations may:

- require the acquisition of various permits and bonds before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to prevent pollution from historical and ongoing operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws and regulations may also restrict our ability to produce natural gas and oil by, among other things, limiting the amount of natural gas and oil we can produce from our wells, limiting the number of wells we are allowed to drill or limiting the locations at which we can conduct our drilling operations. The regulatory burden on the natural gas and oil industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal and clean-up requirements for the natural gas and oil industry could have a significant impact on our operating costs. We believe that operation of our wells is in substantial compliance with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot provide any assurance on how future compliance with environmental laws and regulations may impact our properties or the operations. For the year ended December 31, 2008, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. As of the date of this Annual Report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2009 or that will otherwise have a material impact on our financial position or results of operations.

Environmental laws and regulations that could have a material impact on our operations as well as the natural gas and oil exploration and production industry in general include the following:

National Environmental Policy Act. Natural gas and oil exploitation and production activities on federal lands are subject to the National Environmental Policy Act, as amended, or “NEPA”. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will typically prepare an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Our current exploitation and production activities, as well as proposed exploitation and development plans, on federal lands require governmental permits or similar authorizations that are subject to the requirements of NEPA. This process has the potential to delay, limit or add to the cost of developing natural gas and oil projects.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or “RCRA”, and comparable state laws, regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” as well as the disposal of non-hazardous wastes. Under the auspices of the U.S. Environmental Protection Agency, or “EPA”, individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. While drilling fluids, produced waters, and many other wastes associated with the exploitation, development, and production of crude oil, natural gas, or geothermal energy constitute “solid wastes”, which are regulated under the less stringent non-hazardous waste provisions of the RCRA, there is no assurance that the EPA or individual states will not in the future adopt more stringent and costly requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous. We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations. Although we do not believe the current costs of managing wastes generated by operation of our wells to be significant, any legislative or regulatory reclassification of natural gas and oil exploitation and production wastes could increase our costs to manage and dispose of such wastes.

Hazardous Substance Releases. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as "CERCLA", or "Superfund," and analogous state laws, impose, under certain circumstances, joint and several liability, without regard to fault or legality of conduct, on persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that transported or disposed or arranged for the transportation or disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While materials are generated in the course of operation of our wells that may be regulated as hazardous substances, we have not received any pending notifications that we may be potentially responsible for cleanup costs under CERCLA.

We currently own, lease, or have a non-operating interest in numerous properties that have been used for natural gas and oil exploitation and production for many years. Although we believe that operating and waste disposal practices have been used that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, as amended, or "Clean Water Act", and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other natural gas and oil wastes, into state waters as well as waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that we are in substantial compliance with the requirements of the Clean Water Act.

Air Emissions. The Clean Air Act, as amended, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new emission limitations. These regulations may increase the costs of compliance for some facilities, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance. We believe that we are in substantial compliance with the requirements of the Clean Air Act.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or "OSHA", and comparable state statutes. The OSHA hazard communication standard, EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with the applicable requirements of OSHA.

Climate Change. In response to recent studies suggesting that emissions of certain gases, referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere, the current administration has expressed support for, and it is anticipated that the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. In addition, at least one-third of the states, either individually or through multi-state initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, for greenhouse gas emissions resulting from our operations.

Also, as a result of the U.S. Supreme Court's decision in 2007 in *Massachusetts, et al. v. EPA* and certain provisions of the Clean Air Act, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in the *Massachusetts* decision that greenhouse gases including carbon dioxide fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain CAA programs. In July 2008, EPA released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in *Massachusetts*.

Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. New federal, regional or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the natural gas and oil we produce.

Other Regulation of the Natural Gas and Oil Industry

The natural gas and oil industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the natural gas and oil industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the natural gas and oil industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including natural gas and oil facilities. Our operations may be subject to such laws and regulations. If in the future one or more of our facilities becomes subject to such legislation, then the cost to comply with such law could be substantial.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Regulation of Transportation and Sales. The availability, terms and cost of transportation significantly affect sales of natural gas and oil. The interstate transportation of natural gas is subject to federal regulation primarily by the Federal Energy Regulatory Commission, or "FERC" under the Natural Gas Act of 1938. FERC regulates interstate natural gas pipeline transportation rates and service conditions, which may affect the marketing and sales of natural gas. FERC requires interstate pipelines to offer available firm transportation capacity on an open-access, non-discriminatory basis to all natural gas shippers. FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. State laws and regulations generally govern the gathering and intrastate transportation of natural gas. Natural gas gathering systems in the states in which we operate are generally required to offer services on a non-discriminatory basis, and are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

The ability to transport oil is generally dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act, or subject to regulation by the particular state in which such transportation takes place. Laws and regulation applicable to pipeline transportation of oil largely require pipelines to charge rates published in agency-approved tariffs and require pipelines to provide non-discriminatory access and terms and conditions of service. Certain regulations imposed by FERC, by the United States Department of Transportation and by other regulatory authorities on pipeline transporters in recent years could result in an increase in the cost of pipeline transportation service. We do not believe, however, that these regulations affect us any differently than other producers.

Under the Energy Policy Act of 2005, or "EPAct 2005," Congress made it unlawful for any entity, as defined in the EPAct 2005, including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services regulated by the FERC that violates the FERC's rules. FERC's rules implementing EPAct of 2005 make it unlawful for any entity, directly or indirectly, to use or employ any device, scheme, or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. Pursuant to authority granted to FERC by EPAct 2005, FERC has also put in place additional regulations intended to prevent market manipulation and to promote price transparency. For example, FERC has imposed new rules requiring wholesale purchasers and sellers of natural gas to report to FERC certain aggregated volume and other purchase and sales data for the previous calendar year. While EPAct 2005 reflects a significant expansion of the FERC's enforcement authority, we do not anticipate that we will be affected by EPAct 2005 any differently than energy industry participants.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

The various states regulate the drilling for, and the production, gathering and sale of, natural gas and oil, including imposing severance and other production related taxes and requirements for obtaining drilling permits. For example, currently, a severance tax on natural gas and oil production is imposed at a rate of 4.5%, 3.0% and 3.75% in Kentucky, Tennessee and New Mexico, respectively. Texas currently imposes a 7.5% severance tax on gas production and 4.6% severance tax on oil production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from natural gas and oil wells based on market demand or resource conservation, or both. States do not currently regulate wellhead prices or engage in other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas or oil that may be produced from our wells, to increase our cost of production, to limit the number of wells or locations we can drill and to limit the availability of pipeline capacity to bring our products to market.

The petroleum industry participants are also subject to compliance with various other federal, state and local regulations and laws. Some of these regulations and those laws relate to occupational safety, resource conservation and equal employment opportunity. We do not believe that compliance with these regulations and laws will have a material adverse effect upon the unitholders.

Employees

As of December 31, 2008, we had ten full time employees. Eight of our employees work in our Houston office, one employee works in our office in Lovington, New Mexico and the other in our office in Christoval, Texas. Under the management services agreement with Vinland, we rely on Vinland's employees to operate our existing producing wells in Appalachia and coordinate our development drilling program in Appalachia. In connection with the Permian Basin acquisition, we outsourced the production accounting to a third party and began operating our own wells. With respect to the south Texas properties, the operator manages the operations of all our wells and coordinates any drilling operations that might be conducted on the jointly owned leasehold interests. We also contract for the services of independent consultants involved in land, regulatory, tax, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Offices

We entered into a lease agreement in February 2009 for approximately 8,645 square feet of office space in Houston, Texas. The lease for our Houston office expires in April 2010.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

We may not have sufficient cash from operations to pay quarterly distributions on our common units following establishment of cash reserves and payment of operating costs.

We may not have sufficient cash flow from operations each quarter to pay distributions. Under the terms of our limited liability company agreement, the amount of cash otherwise available for distribution will be reduced by our operating expenses and the amount of any cash reserve amounts that our board of directors establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas and oil we produce;
- the price at which we are able to sell our natural gas and oil production;
- the level of our operating costs;
- the level of our interest expense which depends on the amount of our indebtedness and the interest payable thereon; and
- the level of our capital expenditures.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of our capital expenditures;
- our ability to make working capital borrowings under our credit facility to pay distributions;
- the cost of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- timing and collectibility of receivables;
- restrictions on distributions contained in our credit facility;
- prevailing economic conditions; and
- the amount of cash reserves established by our board of directors for the proper conduct of our business.

As a result of these factors, the amount of cash we distribute in any quarter to our unitholders may fluctuate significantly from quarter to quarter. If we do not achieve our expected operational results or cannot borrow the amounts needed, we may not be able to pay the full, or any, amount of the quarterly distribution, in which event the market price of our common units may decline substantially.

We rely on Vinland, an affiliate of our largest unitholder, to execute our drilling program in Appalachia. If Vinland fails to or inadequately performs, our operations will be disrupted and our costs could increase or our reserves may not be developed, reducing our future levels of production and our cash from operations, which could affect our ability to make cash distributions to our unitholders.

Effective as of January 5, 2007, we entered into various agreements with Vinland, an affiliate of our largest unitholder, under which we rely on Vinland to operate all of our existing producing wells and coordinate our development drilling program in Appalachia. For example, pursuant to a participation agreement that we have entered into with Vinland, Vinland generally has control over our drilling program in Appalachia and has the sole right to determine which wells are drilled until January 1, 2011. Under the agreements, Vinland will also advise and consult with us regarding all aspects of our production and development operations in Appalachia and provide us with administrative support services as necessary or useful for the operation of our business. If Vinland fails to or inadequately performs these functions, our operations in Appalachia will be disrupted and our costs could increase or our reserves may not be developed or properly developed, reducing our future levels of production and our cash from operations, which could affect our ability to make cash distributions to our unitholders.

We may not be able to obtain funding, obtain funding on acceptable terms or obtain funding under our reserve-based credit facility because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, we may be unable to obtain adequate funding under our reserve-based credit facility because our lending counterparties may be unwilling or unable to meet their funding obligations.

Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to grow our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Growing the Company will require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all.

We plan to fund our growth through acquisitions with proceeds from sales of our debt and equity securities and borrowings under our reserve-based credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms or in the proportions that we expect, or at all, and we may be unable refinance our reserve-based credit facility when it expires.

The cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, as well as the credit market and debt and equity capital market conditions discussed above could negatively impact our ability to remain in compliance with the financial covenants under our reserve-based credit facility which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our growth as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or not purse growth opportunities.

Our reserve-based credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We are prohibited from borrowing under our reserve-based credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our reserve-based credit facility reaches or exceeds 90% of the borrowing base. Our borrowing base is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will re-determine the borrowing base based on an engineering report with respect to our natural gas and oil reserves, which will take into account the prevailing natural gas and oil prices at such time. In the future, we may not be able to access adequate funding under our reserve-based credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. In October 2008, our borrowing base was set at $175.0 million. Our next borrowing base redetermination is scheduled for April 2009 utilizing our December 31, 2008 reserve report. The recent declines in commodity prices make it likely that we will be subject to a reduction in our borrowing base at our April 2009 borrowing base redetermination. A continuing decline in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. We anticipate that if, at the time of any distribution, our borrowings equal or exceed 90% of the then-specified borrowing base, our ability to pay distributions to our unitholders in any such quarter will be solely dependent on our ability to generate sufficient cash from our operations.

The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our reserve-based credit facility. Any increase in the borrowing base requires the consent of all the lenders. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under our reserve-based credit facility.

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

Our future 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 recent 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. It is likely that we will be subject to a reduction in our borrowing base at our next scheduled redetermination in April 2009. Further, because we have elected to use the full-cost accounting method, each quarter we must perform a "ceiling test" that is impacted by declining prices. Significant price declines could cause us to take one or more ceiling test write downs, which would be reflected as non-cash charges against current earnings.

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, 2008 and December 31, 2008 ranged from a high of $145.29 to a low of $33.87 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2008 to December 31, 2008 ranged from a high of $13.58 to a low of $5.29. As of March 5, 2009, the NYMEX crude oil spot price per barrel was $43.61 and the NYMEX natural gas spot price per MMBtu was $4.09. 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 recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. If the gas and oil industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can affect the value of our units.

Unless we replace our reserves, our existing reserves and production will decline, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

Producing natural gas and oil wells extract hydrocarbons from underground structures referred to as reservoirs. Reservoirs contain a finite volume of hydrocarbon reserves referred to as reserves in place. Based on prevailing prices and production technologies, only a fraction of reserves in place can be recovered from a given reservoir. The volume of the reserves in place that is recoverable from a particular reservoir is reduced as production from that well continues. The reduction is referred to as depletion. Ultimately, the economically recoverable reserves from a particular well will deplete entirely and the producing well will cease to produce and will be plugged and abandoned. In that event, we must replace our reserves. We do not intend to drill any development wells until market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. As a result, unless we are able over the long-term to replace the reserves that are produced, investors in our units should consider the cash distributions that are paid on the units not merely as a “yield” on the units, but as a combination of both a return of capital and a return on investment. Investors in our units will have to obtain the return of capital invested out of cash flow derived from their investments in units during the period when reserves can be economically recovered. Accordingly, we give no assurances that the distributions our unitholders receive over the life of their investment will meet or exceed their initial capital investment.

Future price declines may result in a write down of our asset carrying values.

Lower natural gas and oil prices may not only decrease our revenues, but also reduce the amount of natural gas and oil that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our natural gas properties for impairments. We are required to perform impairment tests on our assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carry amount may not be recoverable or whenever management’s plans change with respect to those assets. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken and our ability to borrow funds under our reserve-based credit facility, which may affect our ability to fund our operations and acquire additional reserves, which may adversely affect our ability to make cash distributions to our unitholders.

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

We use the full cost method of accounting to report our natural gas and oil properties. Under this method, we capitalize the cost to acquire, explore for, and develop natural gas and oil properties. Under full cost accounting rules, the net capitalized costs of proved natural gas and oil properties may not exceed a “ceiling limit,” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of proved natural gas and oil properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a “ceiling test write down.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test write down would not impact cash flow from operating activities, but it would reduce our members’ equity.

The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when oil and gas prices are low or volatile. In addition, write downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase. For example, natural gas and oil prices declined significantly throughout the second half of 2008. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. This impairment was calculated based on prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil. The volatility in commodity prices has continued and the conditions in the global economic markets have continued to deteriorate. These and other factors could cause us to record additional write downs of our oil and natural gas properties and other assets in the future and incur additional charges against future earnings.

Our acquisition activities will subject us to certain risks.

During 2008, we expanded our operations into the Permian Basin of west Texas and southeastern New Mexico and into south Texas. Any acquisition involves potential risks, including, among other things: the validity of our assumptions about reserves, future production, revenues and costs, including synergies; an inability to integrate successfully the businesses we acquire; a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions; a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions; the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate; the diversion of management's attention to other business concerns; an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; the incurrence of other significant charges, such as impairment of other intangible assets, asset devaluation or restructuring charges; unforeseen difficulties encountered in operating in new geographic areas; an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes; and customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

If our acquisitions do not generate increases in available cash per unit, our ability to make cash distributions to our unitholders could materially decrease.

Vinland controls our drilling program in Appalachia. Should we ask them to, Vinland has agreed to drill not less than 100 gross wells per calendar year for each of the next three years.

Pursuant to a participation agreement that we have entered into with Vinland, Vinland generally has control over our drilling program in Appalachia and has the sole right to determine which wells are drilled until January 1, 2011. During this period, when favorable conditions for drilling exists, we will meet with Vinland on a quarterly basis to review Vinland's proposal to drill not less than 25 nor more than 40 gross wells, in which we will own a 40% working interest, in any quarter. Up to 20% of the proposed wells may be carried over and added to the wells to be drilled in the subsequent quarter, provided that Vinland is required to drill at least 100 gross wells per calendar year. If Vinland proposes the drilling of less than 25 gross wells in any quarter, we have the right to propose the drilling of up to a total of 14 net wells, in which we will own a 100% working interest, in a given quarterly period. If Vinland drills its minimum commitment, we do not have the ability to drill our own additional wells in the AMI. If either party elects not to participate in the drilling of the proposed wells or future operations with respect to drilled wells, such party forfeits all right, title and interest in the natural gas and oil production that may be produced from such wells. Notwithstanding the foregoing, if both parties agree, no drilling is required.

A substantial majority of our properties in the Permian Basin and all of the properties in south Texas are operated by a third party. Because we do not control the development of the non-operated properties, we may not be able to achieve any production from these non-operated properties in a timely manner.

We currently only operate 41 of our 396 gross wells in the Permian Basin and we do not operate any of the wells in south Texas. In addition, we expect that a substantial majority of future wells on our existing Permian Basin properties will be operated by third parties and that all of our future wells in south Texas will be operated by Lewis. As a result, the success and timing of our drilling and development activities on such non-operated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in such properties; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

We could lose our interests in future wells if we fail to participate under our operating agreement with Lewis in the drilling of these wells.

Under the terms of our operating agreement with Lewis, we may elect to forego participation in the future drilling of wells. Should we do so, we will become obligated to transfer without compensation all of our right, title and interest in those wells.

We are exposed to the credit risk of Vinland and any material nonperformance by Vinland could reduce our ability to make distributions to our unitholders.

Effective January 5, 2007, we entered into several agreements with Vinland pursuant to which Vinland operates all of our existing producing wells in Appalachia and coordinates our development drilling program in Appalachia. In addition, Vinland generally has control over our drilling program in Appalachia and has the sole right to determine which wells are drilled until January 1, 2011. In the event Vinland becomes insolvent or is declared bankrupt, we would have to become the operator of our wells in Appalachia and pursue our own drilling program, which would require additional employees and increased expenses. In addition, there are no restrictions on Nami from selling his ownership in Vinland to a third party that should, but may not perform under our agreements with Vinland. Any material nonperformance under our agreements with Vinland could materially and adversely impact our ability to operate and make distributions to our unitholders.

The amount of cash that we have available for distribution to our unitholders depends primarily upon our cash flow and not our profitability.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital or other borrowings, and not solely on our profitability, which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may be able to pay distributions during periods when we incur net losses.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

No one can measure underground accumulations of natural gas or oil in an exact way. Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and/or oil and assumptions concerning future natural gas and oil prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Independent petroleum engineers prepare estimates of our proved reserves. Some of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Also, the calculation of estimated reserves requires certain assumptions regarding future natural gas and oil prices, production levels, and operating and development costs, any of which assumptions may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. For example, if natural gas prices decline by $1.00 per MMBtu or 18% and oil prices declined by $6.00 per barrel or 15%, the standardized measure of our proved reserves as of December 31, 2008 would decrease from $190.1 million to $138.1 million, based on price sensitivity generated from an internal evaluation. Our standardized measure is calculated using unhedged natural gas and oil prices and is determined in accordance with the rules and regulations of the Securities and Exchange Commission or "SEC." Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated natural gas reserves.

We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our natural gas and oil properties will be affected by factors such as:

- the volume, pricing and duration of our natural gas and oil hedging contracts;
- supply of and demand for natural gas and oil;
- actual prices we receive for natural gas and oil;
- our actual operating costs in producing natural gas and oil;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and our ability to make cash distributions to unitholders.

Our operations require substantial capital expenditures, which will reduce our cash available for distribution. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves and adversely affect our ability to make distributions to our unitholders.

The natural gas and oil industry is capital intensive. We have made and ultimately expect to continue to make substantial capital expenditures in our business for the development, production and acquisition of natural gas and oil reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and our financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas and oil we are able to produce from existing wells;
- the prices at which our natural gas and oil is sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our reserve-based credit facility decrease as a result of lower natural gas and oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels or to replace or add to our reserves. Our reserve-based credit facility restricts our ability to obtain new debt financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our reserve-based credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible decline in our reserves and production and a reduction in our cash available for distribution.

Our business depends on gathering and compression facilities owned by third parties and transportation facilities owned by Delta Natural Gas, Columbia Gas Transmission, Enterprise Products Partners, LP and other third-party transporters and we rely on third parties to gather and deliver our natural gas to certain designated interconnects with third-party transporters. Any limitation in the availability of those facilities or delay in providing interconnections to newly drilled wells would interfere with our ability to market the natural gas we produce and could reduce our revenues and cash available for distribution.

The marketability of our natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties in the respective operating areas. The amount of natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, compression or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, some of our wells are drilled in locations that are not serviced by gathering and transportation pipelines, or the gathering and transportation pipelines in the area may not have sufficient capacity to transport the additional production. As a result, we may not be able to sell the natural gas production from these wells until the necessary gathering and transportation systems are constructed. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering, compression and transportation facilities, could reduce our revenues and cash available for distribution.

We depend on certain key customers for sales of our natural gas and oil. To the extent these and other customers reduce the volumes of natural gas and oil they purchase from us, or to the extent these customers cease to be creditworthy, our revenues and cash available for distribution could decline.

For the year ended December 31, 2008, sales of natural gas and oil to Seminole Energy Services, Osram Sylvania, Inc., BP Energy Company, Plains Marketing L.P. and Sunoco Partners Marketing and Terminals, L.P. accounted for approximately 52%, 15%, 10%, 7% and 4%, respectively, of our natural gas and oil revenues. Our top five purchasers during the year ended December 31, 2008, therefore accounted for 88% of our total revenues. To the extent these and other customers reduce the volumes of natural gas and oil that they purchase from us and they are not replaced in a timely manner with a new customer, our revenues and cash available for distribution could decline.

Because we handle natural gas and other petroleum products, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

The operations of our wells are subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- the federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;

- the federal Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;

- RCRA and comparable state laws that impose requirements for the handling and disposal of waste from our facilities; and

- CERCLA and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent hazardous substances for disposal.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and implementing regulations, impose strict, and under certain circumstances, joint and several liability for costs required to clean up and restore sites where hazardous substances or wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resource damage allegedly caused by the release of hazardous substances or other waste products into the environment.

We may incur significant environmental costs and liabilities due to the nature of our business and the hazardous substances and wastes associated with operation of the wells. For example, an accidental release of petroleum hydrocarbons from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, property and natural resource damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance. Please read “Item 1—Business—Operations—Environmental Matters and Regulation.”

Our future distributions and proved reserves will be dependent upon the success of our efforts to prudently acquire, manage and develop natural gas and oil properties that conform to the acquisition profile described in this Annual Report.

In addition to ownership of the properties currently owned by us, unless we acquire properties in the future containing additional proved reserves or successfully develop proved reserves on our existing properties, our proved reserves will decline as the reserves attributable to the underlying properties are produced. In addition, if the costs to develop or operate our properties increase, the estimated proved reserves associated with properties will be reduced below the level that would otherwise be estimated. We will manage and develop our properties, and the ultimate value to us of such properties which we acquire will be dependent upon the price we pay and our ability to prudently acquire, manage and develop such properties. As a result, our future cash distributions will be dependent to a substantial extent upon our ability to prudently acquire, manage and develop such properties.

Suitable acquisition candidates may not be available on terms and conditions that we find acceptable, we may not be able to obtain financing for certain acquisitions, and acquisitions pose substantial risks to our businesses, financial conditions and results of operations. Even if future acquisitions are completed, the following are some of the risks associated with acquisitions, which could reduce the amount of cash available from the affected properties:

- some of the acquired properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;

- we may assume liabilities that were not disclosed or that exceed their estimates;

- we may be unable to integrate acquired properties successfully and may not realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays
  or other operational, technical or financial problems; substantial costs and delays or other operational, technical or financial problems;

- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and

- we may incur additional debt related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

A principal component of our business strategy is to grow our asset base and production through the acquisition of natural gas and oil properties characterized by long-lived, stable production. The character of newly acquired properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. The changes in the characteristics and risk profiles of such new properties will in turn affect our risk profile, which may negatively affect our ability to issue equity or debt securities in order to fund future acquisitions and may inhibit our ability to renegotiate our existing credit facilities on favorable terms.

Locations that we or the operators of our properties decide to drill may not yield natural gas or oil in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we or the operators of our properties drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If we or the operators of our properties drill future wells that we identify as dry holes, our drilling success rate would decline and may adversely affect our results of operations and our ability to pay future cash distributions at expected levels.

Many of our leases are in areas that have been partially depleted or drained by offset wells.

Many of our leases are in areas that have already been partially depleted or drained by earlier offset drilling. This may inhibit our ability to find economically recoverable quantities of natural gas or oil in these areas.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, resulting in temporarily lower cash from operations, which may impact our ability to pay distributions.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2008, we had identified 352 proved undeveloped drilling locations and over 252 additional drilling locations. These identified drilling locations represent a significant part of our strategy. We do not intend to drill any development wells until market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, natural gas prices, drilling and operating costs and drilling results. In addition, NSAI has not assigned any proved reserves to the over 252 unproved drilling locations we have identified and scheduled for drilling and therefore there may exist greater uncertainty with respect to the success of drilling wells at these drilling locations. Our final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the numerous drilling locations we have identified will be drilled within our expected timeframe or will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations and, as a result, our ability to pay distributions to our unitholders.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas or oil can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- the high cost, shortages or delivery delays of equipment and services;

- unexpected operational events;

- adverse weather conditions;

- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions;
- uncontrollable flows of natural gas or well fluids; and
- pipeline capacity curtailments.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

We may incur substantial additional debt in the future to enable us to pursue our business plan and to pay distributions to our unitholders.

Our business requires a significant amount of capital expenditures to maintain and grow production levels. Commodity prices have historically been volatile, and we cannot predict the prices we will be able to realize for our production in the future. As a result, we may borrow, to the extent available, significant amounts under our reserve-based credit facility in the future to enable us to pay quarterly distributions. Significant declines in our production or significant declines in realized natural gas and oil prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

When we borrow to pay distributions, we are distributing more cash than we are generating from our operations on a current basis. This means that we are using a portion of our borrowing capacity under our reserve-based credit facility to pay distributions rather than to maintain or expand our operations. If we use borrowings under our reserve-based credit facility to pay distributions for an extended period of time rather than toward funding capital expenditures and other matters relating to our operations, we may be unable to support or grow our business. Such a curtailment of our business activities, combined with our payment of principal and interest on our future indebtedness to pay these distributions, will reduce our cash available for distribution on our common units. If we borrow to pay distributions during periods of low commodity prices and commodity prices remain low, we may have to reduce or suspend our distribution in order to avoid excessive leverage and debt covenant violations.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas operations in the Appalachian Basin are adversely affected by seasonal weather conditions, primarily in the winter and spring. Many municipalities impose weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. This limits our access to these jobsites and our ability to service wells in these areas.

Our price risk management activities could result in financial losses or could reduce our income, which may adversely affect our ability to pay distributions to our unitholders.

We enter into derivative contracts to reduce the impact of natural gas and oil price volatility on our cash flow from operations. Currently, we use a combination of fixed-price swaps and NYMEX collars and put options to mitigate the volatility of future natural gas and oil prices received. Please read "Item 1—Operations— Price Risk Management Activities" and "Item 7A—Quantitative and Qualitative Disclosure About Market Risk."

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, our price risk management activities are subject to the following risks:

- a counterparty may not perform its obligation under the applicable derivative instrument;

- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and

- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures

If the Asher lease is terminated or if Nami Resource LLC's rights to production under wells in which we have a contract right to receive proceeds from the sale of production are adversely affected, we could lose our contract right to receive proceeds from the sale of production or it could be adversely affected.

Nami Resources, LLC, a subsidiary of our Predecessor that was retained by our founding unitholder, has been involved in an ongoing dispute with Asher Land and Mineral Company, Ltd., or Asher, pursuant to which Asher claims that Nami Resources Company, LLC did not correctly calculate the royalties paid to it and that it failed to abide by certain terms of the leases relating to the coordination of oil and gas development with coal development activities. As part of our separation from Vinland, we received from Nami Resources Company, LLC a contract right to receive approximately 99% of the net proceeds, after deducting royalties paid to other parties, severance taxes, third-party transportation costs, costs incurred in the operation of wells and overhead costs, from the sale of production from certain producing oil and gas wells located within the Asher lease, which accounted for 2.6% of our proved reserves as of December 31, 2008. The Asher lease and the litigation related thereto were retained by Nami Resources Company, LLC. If the Asher lease is terminated or if Nami Resources Company, LLC rights to production under wells in which we have a contract right to receive proceeds from the sale of production are adversely affected, we could lose our contract right to receive proceeds from the sale of production or it could be adversely affected.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our vendors', customers' and counterparties' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors', customers' and counterparties' liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could reduce our ability to make distributions to our unitholders.

We depend on senior management personnel, each of whom would be difficult to replace.

We depend on the performance of Scott W. Smith, our President and Chief Executive Officer, Richard A. Robert, our Executive Vice President and Chief Financial Officer and Britt Pence, our Vice President of Engineering. We maintain no key person insurance for either Mr. Smith, Mr. Robert or Mr. Pence. The loss of any or all of Messrs. Smith, Robert and Pence could negatively impact our ability to execute our strategy and our results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The natural gas and oil industry is intensely competitive, and we compete with other companies that have greater resources. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for natural gas and oil properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low natural gas and oil prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff. Please read "Item1—Business—Operations—Environmental Matters and Regulation" and "Business—Operations—Other Regulation of the Natural Gas and Oil Industry" for a description of the laws and regulations that affect us.

Shortages of drilling rigs, supplies, oilfield services, equipment and crews could delay our operations and reduce our cash available for distribution.

Higher natural gas and oil prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Over the past three years, we and other natural gas and oil companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Sustained periods of lower natural gas and oil prices could bring about the closure or downsizing of entities providing drilling services, supplies, oil field services, equipment and crews. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available for distribution.

Risks Related to Our Structure

Mr. Nami, who together with certain of his affiliates and related persons, own approximately 26.8% of our outstanding common units, and a certain member of our board of directors is a director of Vinland Energy, LLC and may have conflicts of interest with us. The ultimate resolution of any such conflict of interest may result in favoring the interests of these other parties over our unitholders' and may be to our detriment. Our limited liability company agreement limits the remedies available to our unitholders in the event unitholders have a claim relating to conflicts of interest.

One member of our board of directors is a director of Vinland, which is 90% owned by Nami. Conflicts of interest may arise between Nami and his affiliates, including Vinland, and a certain member of our board of directors, on the one hand, and us and our unitholders, on the other hand. These potential conflicts may relate to the divergent interests of these parties. Situations in which the interests of Nami and his affiliates, including Vinland and a certain member of our board of directors may differ from interests of owners of units include, among others, the following situations:

- our limited liability company agreement gives our board of directors broad discretion in establishing cash reserves for the proper conduct of our business, which will affect the amount of cash available for distribution. For example, our board of directors will use its reasonable discretion to establish and maintain cash reserves sufficient to fund our drilling program;

- none of our limited liability company agreement, management services agreement, participation agreement nor any other agreement requires Nami or any of his affiliates, including Vinland, to pursue a business strategy that favors us. Directors and officers of Vinland and its subsidiaries have a fiduciary duty while acting in the capacity as such director or officer of Vinland or such subsidiary to make decisions in the best interests of the members or stockholders of Vinland, which may be contrary to our best interests;

- we rely on Vinland to operate and develop our properties in Appalachia;

- we depend on Vinland to gather, compress, deliver and provide services necessary for us to market our natural gas in Appalachia; and

- Nami and his affiliates, including Vinland, are not prohibited from investing or engaging in other businesses or activities that compete with us.

If in resolving conflicts of interest that exist or arise in the future our board of directors or officers, as the case may be, satisfy the applicable standards set forth in our limited liability company agreement for resolving conflicts of interest, unitholders will not be able to assert that such resolution constituted a breach of fiduciary duty owed to us or to unitholders by our board of directors and officers.

We may issue additional units without unitholder approval, which would dilute their existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including units, without the approval of our unitholders.

The issuance of additional units or other equity securities may have the following effects:

- the proportionate ownership interest of unitholders in us may decrease;

- the amount of cash distributed on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the units may decline.

Our limited liability company agreement restricts the voting rights of unitholders owning 20% or more of our units.

Our limited liability company agreement restricts the voting rights of unitholders by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our founding unitholder and his affiliates or transferees and persons who acquire such units with the prior approval of the board of directors, cannot vote on any matter. Our limited liability agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting unitholders' ability to influence the manner or direction of management.

Our limited liability company agreement provides for a limited call right that may require unitholders to sell their units at an undesirable time or price.

If, at any time, any person owns more than 90% of the units then outstanding, such person has the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining units then outstanding at a price not less than the then-current market price of the units. As a result, unitholders may be required to sell their units at an undesirable time or price and therefore may receive a lower or no return on their investment. Unitholders may also incur tax liability upon a sale of their units.

The price of our common units could be subject to wide fluctuations, unitholders could lose a significant part of their investment.

During 2008, our unit price closed at a high of $18.41 on May 20, 2008 and declined to a closing low of $4.72 on December 23, 2008. The market price of our common units is subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- fluctuations in broader securities market prices and volumes, particularly among securities of natural gas and oil companies and securities of publicly traded limited partnerships and limited liability companies;
- changes in general conditions in the U.S. economy, financial markets or the natural gas and oil industry;
- changes in securities analysts' recommendations and their estimates of our financial performance;
- the public's reaction to our press releases, announcements and our filings with the SEC;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other natural gas and oil companies;
- variations in the amount of our quarterly cash distributions; and
- future issuances and sales of our units.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 18-607 of the Delaware Revised Limited Liability Company Act, or the "Delaware Act," we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, members or unitholders who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited liability company for the distribution amount. A purchaser of common units who becomes a member or unitholder is liable for the obligations of the transferring member to make contributions to the limited liability company that are known to such purchaser of units at the time it became a member and for unknown obligations if the liabilities could be determined from our limited liability company agreement.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly-traded limited liability company interests. Reduced demand for our units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, taxes paid, if any, would reduce the amount of cash available for distribution to unitholders.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter that affects us.

Despite the fact that we are a limited liability company (LLC) under Delaware law, it is possible in certain circumstances for an LLC such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gain, loss, deduction or credit would flow through to unitholders. Because a tax may be imposed on us as a corporation, our cash available for distribution to our unitholders could be reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been recently considered that would have eliminated partnership tax treatment for certain publicly traded LLCs. Although such legislation would not have appeared to have applied to us as currently proposed, it could be reconsidered in a manner that would apply to us. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are required to pay Texas franchise tax which is assessed on Texas sourced taxable margin defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. If any other state were to impose a tax upon us as an entity, the cash available for distribution to unitholders would be reduced.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted and the costs of any IRS contest will reduce our cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from their share of our taxable income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decreases the tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholders sells their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning units that may result in adverse tax consequences to them.

Investment in units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual units purchased. The

IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. If treated as a new partnership, we must make new tax election and could be subject to penalties if we are unable to determine that a termination occurred.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Kentucky, New Mexico, Tennessee and Texas. Each of these states, other than Texas, imposes an income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Part I, Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. 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 governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Nami Resources Company, LLC, a subsidiary of our Predecessor that was retained by our founding unitholder in connection with the Restructuring, has been involved in an ongoing dispute with Asher Land and Mineral Company, Ltd., or Asher, pursuant to which Asher claims, among other things, that Nami Resources Company, LLC did not correctly calculate the royalties paid to it and that it failed to abide by certain terms of the leases relating to the coordination of oil and gas development with coal development activities.

On September 8, 2006, Asher filed a complaint in Kentucky state court initiating an action styled *Asher Land and Mineral, Ltd. v. Nami Resources Company, LLC,* Bell Circuit Court, Civil Action No. 06-CI-00417. In that action, Asher sought monetary damages and court-ordered rescission of the leases. Before a responsive pleading was filed, Asher voluntarily withdrew its complaint and dismissed the case. On December 15, 2006, Asher filed a new action styled *Asher Land and Mineral, Ltd. v. Nami Resources Company, LLC*, Bell Circuit Court, Civil Action No. 06-CI-00566. In that action, Asher has made the same allegations as in the prior suit and added a claim for an undetermined amount of punitive damages. The parties have exchanged limited initial discovery requests.

On August 29, 2007, Asher filed a motion to add additional defendants to the action cited above, including Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC and Trust Energy Company, LLC. The Company has filed several motions to be dismissed from this action but to date is still a named defendant in this case. Since that time, no discovery has been sought from the Company by Asher. We have retained separate counsel to represent us in this case as it progresses and intend to continue to vigorously defend the action.

We received a contract right to receive approximately 99% of the net proceeds from the sale of production from certain producing oil and gas wells located within the Asher lease, which accounted for approximately 2.6% of our estimated proved reserves as of December 31, 2008. We did not receive an assignment of any working interest in the Asher lease. The Asher lease and the litigation related thereto were retained by Nami Resources Company, LLC. If the Asher lease is terminated or if Nami Resources Company, LLC’s rights to production under wells of which we have contract rights to receive proceeds are adversely affected, we could lose our contract rights to receive such proceeds or it could be adversely affected.

Nami Resources Company, LLC and Vinland have agreed to indemnify us for all liabilities, judgments and damages that may arise in connection with the litigation referenced above as well as providing for the defense of any such claims. The indemnities agreed to by Nami Resources Company, LLC and Vinland will remain in place until the resolution of the Asher litigation.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITYHOLDERS

None.

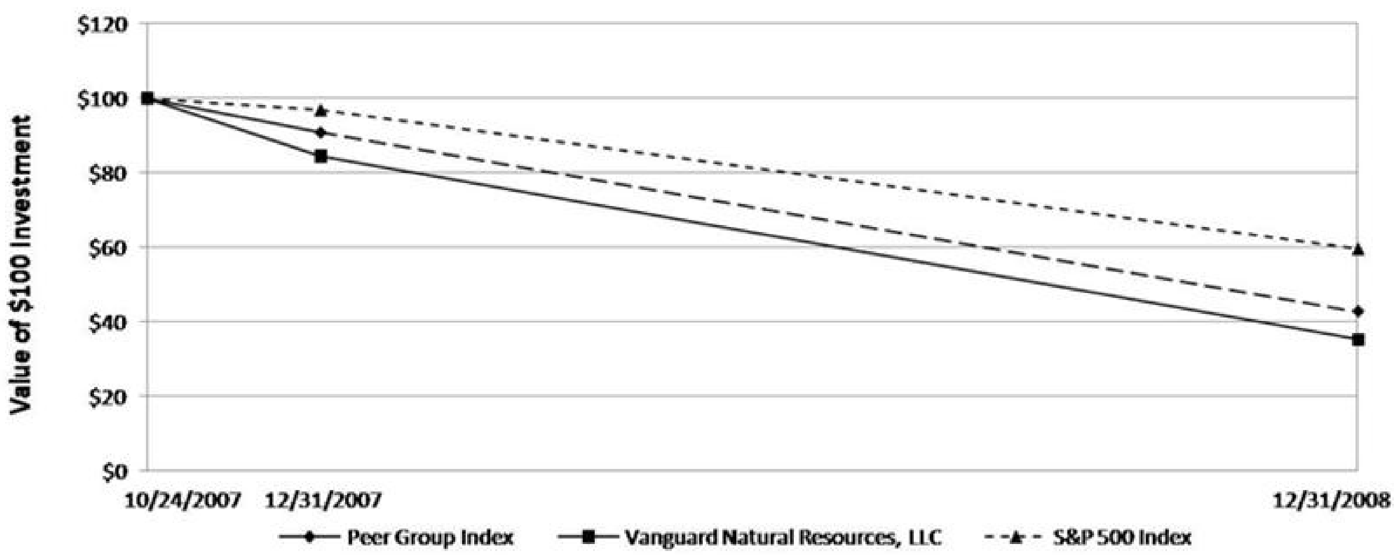
PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON UNITS, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are traded on the NYSE Arca, Inc. under the symbol “VNR”. Our units began trading on October 24, 2007, in connection with our IPO. On March 5, 2009, there were 12,145,873 common units outstanding and approximately eleven unitholders, which does not include beneficial owners whose units are held by a clearing agency, such as a broker or a bank. On March 5, 2009, the market price for our common units was $8.85 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $78,728,476. The following table presents the high and low sales price for our common units during the periods indicated.

	Common Units	
	High	Low
2008		
Fourth Quarter	$ 12.00	$ 4.62
Third Quarter	$ 16.75	$ 11.70
Second Quarter	$ 18.55	$ 15.30
First Quarter	$ 17.25	$ 13.55
2007		
Fourth Quarter	$ 19.15	$ 14.12

Stock Performance Graph. The performance graph below compares total unitholder return on our units, with the total return of the Standard & Poor's 500 Index, or "S&P 500 Index" and our Peer Group Index, a weighted composite of nine natural gas and oil production publicly traded partnerships. Total return includes the change in the market price, adjusted for reinvested dividends or distributions, for the period shown on the performance graph and assumes that $100 was invested in VNR at the last reported sale price of units as reported by NYSE Arca, Inc. ($18.94) on October 24, 2007 (the day trading of units commenced), and in the S&P 500 Index and our peer group index on the same date. The results shown in the graph below are not necessarily indicative of future performance.



	October 24, 2007	December 31, 2007	December 31, 2008
Vanguard Natural Resources, LLC	$ 100	$ 84.48 (1)	$ 35.37 (1)
Peer Group Index	$ 100	$ 90.76	$ 42.75
S&P 500 Index	$ 100	$ 96.87	$ 59.59

(1) Based on the last reported sale price of VNR units as reported by NYSE Arca, Inc. on December 31, 2007 ($16.00) and 2008 ($5.90).

Distributions Declared. The following table shows the amount per unit, record date and payment date of the quarterly cash distributions we paid on each of our common units for each period presented. Future distributions are at the discretion of our board of directors and will depend on business conditions, earnings, our cash requirements and other relevant factors.

	Cash Distributions		
	Per Unit	Record Date	Payment Date
2008			
Fourth Quarter	$ 0.50	January 30, 2009	February 14, 2009
Third Quarter	$ 0.50	October 31, 2008	November 14, 2008
Second Quarter	$ 0.445	July 31, 2008	August 14, 2008
First Quarter	$ 0.445	April 30, 2008	May15, 2008

2007				
Fourth Quarter	$	0.425(1)	February 7, 2008	February 14, 2008

(1) This distribution was pro-rated for the period from the closing of the IPO on October 29, 2007 through December 31, 2007, resulting in a distribution of $0.291 per unit for the period.

Our limited liability company agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended December 31, 2007, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation:

(a) the sum of:

(i) all our and our subsidiaries' cash and cash equivalents (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly owned) on hand at the end of that quarter; and

(ii) all our and our subsidiaries' additional cash and cash equivalents (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly owned) on hand on the date of determination of available cash for that quarter resulting from working capital borrowings made subsequent to the end of such quarter,

(b) less the amount of any cash reserves established by the board of directors (or our proportionate share of cash and cash equivalents in the case of subsidiaries that are not wholly owned) to:

(i) provide for the proper conduct of our or our subsidiaries' business (including reserves for future capital expenditures, including drilling and acquisitions, and for our and our subsidiaries' anticipated future credit needs),

(ii) comply with applicable law or any loan agreement, security agreement, mortgage, debt instrument or other agreement or obligation to which we or any of our subsidiaries is a party or by which we are bound or our assets are subject; or

(iii) provide funds for distributions to our unitholders with respect to any one or more of the next four quarters;

provided that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of a quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if the board of directors so determines.

Equity Compensation Plans. See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for information regarding our equity compensation plans as of December 31, 2008.

Unregistered Sale of Equity Securities and Use of Proceeds. On July 28, 2008, we completed the acquisition of certain natural gas and oil properties located in the Dos Hermanos Field in Webb County, Texas from Segundo Navarro Drilling, Ltd., a wholly owned subsidiary of the Lewis Energy Group. As consideration for the purchase, we paid $30.0 million in cash and issued 1,350,873 unregistered common units, valued at $15.81 per unit.

ITEM 6. SELECTED FINANCIAL DATA

Set forth below is our summary of our consolidated financial and operating data for the periods indicated for Vanguard Natural Resources, LLC and our Predecessor. The historical financial data for the years ended December 31, 2004, 2005 and 2006 and the balance sheet data as of December 31, 2005 and 2006 have been derived from the audited financial statements of our Predecessor. Please read "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations—Comparability of Our Financial Statements to Our Predecessor" for the reasons why the historical financial statements of our Predecessor included in this Annual Report on Form 10-K may not be comparable to our results of operations.

The selected financial data should be read together with Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data included in this Report on Form 10-K.

The following table presents a non-GAAP financial measure, adjusted EBITDA, which we use in our business. This measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to the most directly comparable financial measure calculated and presented in accordance with GAAP in "Non-GAAP Financial Measure."

	Year Ended December 31, (6) (7) (in thousands, except per unit data)				
	Vanguard		Vanguard Predecessor		
	2008	2007	2006	2005	2004
Statement of Operations Data:					
Revenues:					
Natural gas and oil sales	$ 68,850	$ 34,541	$ 38,184	$ 40,299	$ 23,881
Gain (loss) on commodity cash flow hedges (1)	269	(702)	—	—	—
Gain (loss) on other commodity derivative contracts (1)	32,477	—	15,540	(28,803)	(6,917)
Other	—	—	665	451	29
Total revenues	101,596	33,839	54,389	11,947	16,993
Costs and Expenses:					
Lease operating expenses	11,112	5,066	4,896	4,607	2,407
Depreciation, depletion and amortization	14,910	8,981	8,633	6,189	4,029
Impairment of natural gas and oil properties	58,887	—	—	—	—
Selling, general and administrative	6,715 (2)	3,507 (2)	5,199	5,946	3,154
Bad debt expense	—	1,007	—	—	—
Taxes other than income	4,965	2,054	1,774	1,249	611
Total costs and expenses	96,589	20,615	20,502	17,991	10,201
Income (Loss) from Operations:	5,007	13,224	33,887	(6,044)	6,792
Other Income and (Expenses):					
Interest income	17	62	40	52	7
Interest and financing expenses	(5,491)	(8,135)	(7,372)	(4,566)	(1,455)
Loss on interest rate derivative contracts (3)	(3,284)	—	—	—	—
Loss on extinguishment of debt	—	(2,502)	—	—	—
Total other expenses	(8,758)	(10,575)	(7,332)	(4,514)	(1,448)
Net income (loss)	$ (3,751)	$ 2,649	$ 26,555	$ (10,558)	$ 5,344
Net income (loss) per unit:					
Common and Class B units- basic & diluted (4)	$ (0.32)	$ 0.39			
Cash Flow Data:					
Net cash provided by operating activities (1)	$ 39,555	$ 1,372	$ 16,087	$ 10,530	$ 9,607
Net cash used in investing activities	(119,540)	(26,409)	(37,383)	(37,068)	(19,598)
Net cash provided by (used in) financing activities	76,878	26,415	19,985	25,571	(12,721)
Other Financial Information (unaudited):					
Adjusted EBITDA (5)	$ 48,754	$ 30,395	$ 24,772	$ 18,924	$ 11,812

(1) Natural gas and oil derivative contracts were used to reduce our exposure to changes in natural gas and oil prices. Prior to 2007, they were not specifically designated as hedges under Statement of Financial Accounting Standards (SFAS) No. 133 *"Accounting for Derivatives Instruments and Hedging Activities"* ("SFAS 133"), thus the changes in the fair value of commodity derivative contracts were marked to market in our earnings. In 2007, we designated all commodity derivative contracts as cash flow hedges; therefore, the changes in fair value in 2007 are included in other comprehensive income (loss). In 2008, all commodity derivative contracts were either de-designated as cash flow hedges or they failed to meet the hedge documentation requirements for cash flow hedges. As a result, (a) for the cash flow hedges that were settled in 2008, the change in fair value through December 31, 2007 has been reclassified to earnings from accumulated other comprehensive loss and is classified as gain on commodity cash flow hedges and (b) the changes in the fair value of other commodity derivative contracts are recorded in earnings and classified as gain on other commodity derivative contracts. Unrealized gains (losses) on other commodity derivative contracts, which represent non-cash charges, were $39.0 million, $17.7 million, $(18.8) million and $(1.0) million in 2008, 2006, 2005 and 2004, respectively.

(2) Includes $3.6 million and $2.1 million of non-cash unit-based compensation expense in 2008 and 2007, respectively.

(3) Includes $3.2 million in unrealized losses in 2008.

(4) No calculation of earnings per unit was made for the Vanguard Predecessor as there was a single member interest prior to 2007.

(5) See “Non-GAAP Financial Measure” below.

(6) The Permian acquisition closed on January 31, 2008 and, as such, only eleven months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007, 2006, 2005 and 2004.

(7) The south Texas acquisition closed on July 28, 2008 and, as such, only five months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007, 2006, 2005 and 2004.

	As of December 31, (1) (2) (in thousands)				
	Vanguard		Vanguard Predecessor		
	2008	2007	2006	2005	2004
Balance Sheet Data:					
Cash and cash equivalents	$ 3	$ 3,110	$ 1,731	$ 3,041	$ 4,009
Short-term derivative assets	22,184	4,017	—	—	—
Other current assets	9,691	4,826	20,438	19,598	10,033
Natural gas and oil properties, net of accumulated depreciation, depletion, amortization and accretion	182,269	106,983	104,684	83,513	54,761
Property, plant and equipment, net of accumulated depreciation	184	166	11,873	4,104	1,894
Long-term derivative assets	15,749	1,330	—	—	—
Other assets	2,482	10,747	—	—	—
Total Assets	$ 232,562	$ 131,179	$ 138,726	$ 110,256	$ 70,697
Short-term derivative liabilities	$ 487	$ —	$ 2,022	$ 11,527	$ 800
Other current liabilities	7,277	5,355	11,505	12,033	6,347
Long-term debt	135,000	37,400	94,068	72,708	42,318
Long-term derivative liabilities	2,313	5,903	—	8,243	191
Other long-term liabilities	2,134	190	418	212	130
Members’ capital	85,351	82,331	30,713	5,533	20,911
Total Liabilities and Members’ Capital	$ 232,562	$ 131,179	$ 138,726	$ 110,256	$ 70,697

(1) The Permian acquisition closed on January 31, 2008 and, as such, only eleven months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007, 2006, 2005 and 2004.

(2) The south Texas acquisition closed on July 28, 2008 and, as such, only five months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007, 2006, 2005 and 2004.

Summary Reserve and Operating Data

The following tables show estimated net proved reserves based on a reserve report prepared by our independent petroleum engineers, NSAI, and certain summary unaudited information with respect to our production and sales of natural gas and oil. You should refer to “Item 1A—Risk Factors,” “Item 7—Management’s Discussion and Analysis of Financial Condition and Results of Operations,” “Item 1—Business—Natural Gas and Oil Data—Proved Reserves” and “—Production and Price History” included in this Annual report on Form 10-K in evaluating the material presented below.

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		As of December 31, 2008
Reserve Data:		
Estimated net proved reserves:		
Natural gas (Bcf)		81.2
Crude oil (MBbls)		4,547
Total (Bcfe)		108.5
Proved developed (Bcfe)		80.9
Proved undeveloped (Bcfe)		27.6
Proved developed reserves as % of total proved reserves		75%
Standardized Measure (in millions) (1)	$	190.1
Representative Natural Gas and Oil Prices:		
Natural gas—spot Henry Hub per MMBtu	$	5.71
Oil—WTI per Bbl	$	41.00

	Year Ended December 31,					
	Vanguard				Vanguard Predecessor	
	2008		2007		2006	
Net Production:						
Total realized production (MMcfe)		5,931		4,238		4,378
Average daily production (Mcfe/day)		16,206(2)		11,610		11,995
Average Realized Sales Prices ($ per Mcfe):						
Average sales prices (including hedges)	$	11.43(3)	$	8.99(3)	$	8.22
Average sales prices (excluding hedges)	$	11.61	$	8.15	$	8.72
Average Unit Costs ($ per Mcfe):						
Production costs	$	2.71	$	1.68	$	1.52
Selling, general and administrative expenses	$	1.13(5)	$	0.83(5)	$	1.19
Depreciation, depletion, amortization and accretion	$	2.51	$	2.12	$	1.97

(1) Standardized Measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as selling, general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion, amortization and accretion and discounted using an annual discount rate of 10%. Our Standardized Measure does not include future income tax expenses because we are not subject to income taxes and our reserves are owned by our subsidiary Vanguard Natural Gas, LLC which is also not subject to income taxes. Standardized Measure does not give effect to derivative transactions. For a description of our derivative transactions, please read "Item 1—Operations—Price Risk Management Activities" and "Item 7A—Quantitative and Qualitative Disclosures About Market Risk."

(2) Average daily production for 2008 calculated based on 366 days including production for the Permian Basin and south Texas acquisitions from the closing dates of these acquisitions.

(3) Excludes amortization of premiums paid and non-cash settlement on derivative contracts.

(4) Production costs include such items as lease operating expenses, production taxes (severance and ad valorem taxes) as well as gathering and compression fees and other customary charges.

(5) Includes $3.6 million ($.60/Mcfe) and $2.1 million ($0.51/Mcfe) of non-cash unit-based compensation expense in 2008 and 2007, respectively.

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;
- Loss on extinguishment of debt;
- Depreciation, depletion and amortization (including accretion of asset retirement obligations);
- Impairment of natural gas and oil properties;
- Bad debt expenses;
- Amortization of premiums paid and non-cash settlement on derivative contracts;
- Unrealized gains and losses on other commodity and interest rate derivative contracts;
- Change in fair value of derivative contracts;
- Deferred tax liabilities;
- Unit-based compensation expense; and
- Realized gains and losses on cancelled derivatives.

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.

The following table presents a reconciliation of our consolidated net income (loss) to adjusted EBITDA:

	Year Ended December 31, (in thousands)				
	Vanguard		Vanguard Predecessor		
	2008	2007	2006	2005	2004
Net Income (Loss)	$ (3,751)	$ 2,649	$ 26,555	$ (10,558)	$ 5,344
Plus:					
Interest expense, including realized loss on interest rate derivative contracts	5,597	8,135	7,372	4,566	1,455
Loss on extinguishment of debt	—	2,502	—	—	—
Depreciation, depletion, amortization and accretion	14,910	8,981	8,633	6,189	4,029
Impairment of natural gas and oil properties	58,887	—	—	—	—
Bad debt expense	—	1,007	—	—	—
Amortization of premiums paid and non-cash settlement on derivative contracts	5,226	4,274	—	—	—
Unrealized (gains) losses on other commodity and interest rate derivative contracts (1)	(35,852)	—	(17,748)	18,779	991

Deferred tax liability	177	—	—	—	—
Unit-based compensation expense	3,577	2,132	—	—	—
Realized loss on cancelled derivatives	—	777	—	—	—
Less:					
Interest income	17	62	40	52	7
Adjusted EBITDA	$ 48,754	$ 30,395	$ 24,772	$ 18,924	$ 11,812

(1) Natural gas and oil derivative contracts were used to reduce our exposure to changes in natural gas and oil prices. Prior to 2007, they were not specifically designated as hedges under FAS 133, thus the changes in the fair value of commodity derivative contracts were marked to market in our earnings and classified as gain (loss) on other commodity derivative contracts. In 2007, we designated all commodity derivative contracts as cash flow hedges. In 2008, all commodity derivative contracts were either de-designated as cash flow hedges or they failed to meet the hedge documentation requirements for cash flow hedges. As a result, the changes in the fair value of other commodity derivative contracts are recorded in earnings and classified as gain on other commodity derivative contracts. The changes in fair value of interest rate derivative contracts in recorded in earnings and classified as loss on interest rate derivative contracts.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OFOPERATIONS

The following discussion and analysis should be read in conjunction with "Item 6 – Selected Financial Data" and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, particularly in "Item 1A –Risk Factors" and "Forward Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

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. As of December 31, 2008, 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.

At December 31, 2008, we owned working interests in 1,444 gross (958 net) productive wells. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. As of December 31, 2008, we had a 40% working interest in approximately 109,500 gross undeveloped acres surrounding or adjacent to our existing wells located in the Appalachian Basin. In south Texas, we own working interests ranging from 45-50% in approximately 5,300 undeveloped acres surrounding our existing wells. Approximately 25% or 27.6 Bcfe of our estimated proved reserves were attributable to our working interests in undeveloped acreage.

Initial Public Offering

In October 2007, we completed our IPO of 5.25 million units representing limited liability interests in VNR at $19.00 per unit for net proceeds of $92.8 million after deducting underwriting discounts and fees of $7.0 million. In addition, we incurred offering costs of $2.8 million in connection with the IPO .The proceeds were used to reduce indebtedness under our reserve-based credit facility by $80.0 million and the balance was used for the payment of accrued distributions to pre-IPO unitholders and the payment of a deferred swap obligation.

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 natural gas and oil 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. With respect to operations, we have established two district offices, one in Lovington, New Mexico and the other in Christoval, Texas to manage these assets. Our operating focus will be on maximizing existing production and looking for complementary acquisitions that we can add to this operating platform. With this acquisition, based on internal reserve estimates, we acquired 4.4 million barrels of oil equivalent, 83% of which is oil and 90% of which is proved developed producing.

South Texas Acquisition

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. 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 to do so. Based on internal reserve estimates, we acquired 20 Bcfe of proved reserves, 98% of which is natural gas and 65% of which is proved developed producing. 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 for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008.

Our Relationship with Vinland

On April 18, 2007 but effective as of January 5, 2007, we entered into various agreements with Vinland, under which we rely on Vinland to operate our existing producing wells in Appalachia and coordinate our development drilling program in Appalachia. We expect to benefit from the substantial development and operational expertise of Vinland management in the Appalachian Basin. Under a management services agreement, Vinland advises and consults with us regarding all aspects of our production and development operations in Appalachia and provides us with administrative support services as necessary for the operation of our business. In addition, Vinland may, but does not have any obligation to, provide us with acquisition services under the management services agreement. While Vinland is not obligated to provide us with acquisition services, we expect that due to significant common ownership Vinland has an incentive to grow our business by helping us to identify, evaluate and complete acquisitions that will be accretive to our distributable cash. In addition, under a gathering and compression agreement that we entered into with Vinland Energy Gathering, LLC (“VEG”), VEG gathers, compresses, delivers and provides the services necessary for us to market our natural gas production in the area of mutual interest, or AMI. VEG will deliver our natural gas production to certain designated interconnects with third-party transporters. Since the various agreements were executed on April 18, 2007 but were effective as of January 5, 2007, Vinland reimbursed us for the drilling costs and expenses that we incurred on their behalf associated with their interest in the wells drilled between January 5, 2007 and April 18, 2007. In addition, Vinland reimbursed us for selling, general and administrative expenses that we incurred on their behalf between January 5, 2007 and April 18, 2007. We reimbursed Vinland for certain transaction costs and expenses relating to entering into these agreements.

Restructuring Plan

Prior to the separation, our Predecessor owned all of the assets in Appalachia that are currently owned by us and Vinland. As part of the separation of our operating company and Vinland, effective January 5, 2007, we conveyed to Vinland 60% of our Predecessor’s working interest in the known producing horizons in approximately 95,000 gross undeveloped acres in the AMI, 100% of our Predecessor’s interest in an additional 125,000 undeveloped acres and certain coalbed methane rights located in the Appalachian Basin, the rights to any natural gas and oil located on our acreage at depths above and 100 feet below our known producing horizons, all of our gathering and compression assets and all employees except, our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer. 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 in the AMI and a contract right to receive approximately 99% of the net proceeds, after deducting royalties paid to other parties, severance taxes, third-party transportation costs, costs incurred in the operation of wells and overhead costs, from the sale of production from certain producing natural gas and oil wells, which accounted for approximately 2.6% of our estimated proved reserves as of December 31, 2008. In addition, we changed the name of our operating company from Nami Holding Company, LLC to Vanguard Natural Gas, LLC. Collectively, we refer to these events as the “Restructuring.”

Private Offering

In April 2007, we completed a private equity offering pursuant to which we issued 2,290,000 units to certain private investors, which we collectively refer to as the Private Investors, for $41.2 million. We used the net proceeds of this private equity offering to make a distribution to Majeed S. Nami, VNR's largest unitholder, who used a portion of these funds to capitalize Vinland and also paid us $3.9 million to reduce outstanding accounts receivable from Vinland. We then used the $3.9 million to repay borrowings and interest under our reserve-based credit facility, and for general limited liability company purposes. Under the terms of the private offering, all outstanding units accrued distributions at $1.75 annually from the closing of the private offering to September 30, 2007 and then distributions payable to the Private Investors only increased to $2.40 until the completion of the IPO at which time all accrued distributions totaling $5.6 million were paid.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility which is available for our general limited liability company purposes, including, without limitation, capital expenditures and acquisitions. Our obligations under the reserve-based credit facility are secured by substantially all of our assets. Our initial borrowing base under the reserve-based credit facility was set at $115.5 million. However, the borrowing base was subject to $1.0 million reductions per month starting on July 1, 2007 through November 1, 2007, which resulted in a borrowing base of $110.5 million as reaffirmed in November 2007 pursuant to a semi-annual borrowing base redetermination. We applied $80.0 million of our net proceeds from our IPO in October 2007 to reduce our indebtedness under our reserve-based credit facility. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In October 2008, our borrowing base was set at $175.0 million. Our next borrowing base redetermination is scheduled for April 2009 utilizing our December 31, 2008 reserve report. As a result of lower commodity prices, it is likely that we will be subject to a decrease in our borrowing base at our April 2009 redetermination. Until the redetermination occurs, the amount of the potential reduction is uncertain but based on preliminary discussions with our lead bank the expected reduction would not be material to the borrowing base as a whole and would not inhibit our ability to make distributions to our unitholders.

Additional borrowings under our reserve-based credit facility 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, Compass Bank. As a result, indebtedness under the reserve-based credit facility totaled $135.0 million at December 31, 2008 and the applicable margins and the utilization percentages on our borrowing base utilization grid were changed to reflect the following:

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%

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.

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 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to raise debt and equity at prices that are similar to offerings in recent years to be limited as long as the capital markets remain constrained.

During 2008, our unit price closed at a high of $18.41 on May 20, 2008 and declined to a closing low of $4.72 on December 23, 2008, which is the lowest our unit price has closed at since our initial public offering. Since that date our unit price has partially recovered to a level of $8.85 on March 5, 2009. 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, could require reductions in our capital spending, and could require a reduction in our distribution. In the near-term we will focus on maximizing returns on existing assets by managing our costs and selectively deploying capital to improve existing production.

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 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. 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 re-determined 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.

Comparability of Our Financial Statements to Our Predecessor

The historical financial statements of our Predecessor included in this Annual Report on Form 10-K may not be comparable to our results of operations for the following reasons:

- On April 18, 2007, but effective January 5, 2007, we conveyed to Vinland 60% of our Predecessor's working interest in the known producing horizons in approximately 95,000 gross undeveloped acres in the AMI, 100% of our Predecessor's interest in an additional 125,000 undeveloped acres and certain coalbed methane rights located in the Appalachian Basin, the rights to any natural gas and oil located on our acreage at depths above and 100 feet below our known producing horizons and all of our gathering and compression assets. In addition, all of the employees except, our President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer, were transferred to Vinland.

- On April 18, 2007, but effective January 5, 2007, we entered into a management services agreement and a gathering and compression agreement with Vinland which fixed a portion of our production costs for wells owned in the area of mutual interest.

- Our Predecessor did not account for its derivative instruments as cash flow hedges under SFAS 133. Accordingly, the changes in the fair value of its derivative instruments were reflected in earnings for all periods prior to 2007 and in other comprehensive income (loss) for the year ended December 31, 2007. In 2008, unrealized gains and losses were recorded in earnings as all commodity and interest rate derivative contracts were either de-designated as cash flow hedges or they failed to meet the hedge documentation requirements for cash flow hedges.

Results of Operations

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

	Year Ended December 31, (a) (b) (in thousands)		
	Vanguard		Vanguard Predecessor
	2008	2007	2006
Revenues:			
Gas sales	$ 44,920	$ 32,517	$ 36,306
Oil sales	23,930	2,024	1,878
Natural gas and oil sales	68,850	34,541	38,184
Gain (loss) on commodity cash flow hedges	269	(702)	—
Gain on other commodity derivative contracts	32,477	—	15,540

Other	—	—	665
Total revenues	$ 101,596	$ 33,839	$ 54,389
Costs and expenses:			
Lease operating expenses	$ 11,112	$ 5,066	$ 4,896
Depreciation, depletion, amortization and accretion	14,910	8,981	8,633
Impairment of natural gas and oil properties	58,887	—	—
Selling, general and administrative expenses	6,715	3,507	5,199
Bad debt expense	—	1,007	—
Production and other taxes	4,965	2,054	1,774
Total costs and expenses	$ 96,589	$ 20,615	$ 20,502
Other expenses:			
Interest expense, net	$ (5,474)	$ (8,073)	$ (7,332)
Loss on interest rate derivative contracts	(3,284)	—	—
Loss on extinguishment of debt	—	(2,502)	—

(a) The Permian acquisition closed on January 31, 2008 and, as such, only eleven months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007 and 2006.

(b) The south Texas acquisition closed on July 28, 2008 and, as such, only five months of operations are included in the year ended December 31, 2008 and were not included in the results of 2007 and 2006.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues

Natural gas and oil sales increased $34.3 million to $68.8 million during the year ended December 31, 2008 as compared to the same period in 2007. The key revenue measurements were as follows:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	3,578	4,044	(12)%
Permian gas (MMcf)	218(a)	—	N/A
South Texas gas (MMcf)	566(b)	—	N/A
Total natural gas production (MMcf)	4,362	4,044	8%
Average Appalachian daily gas production (Mcf/day)	9,777	11,080	(12)%
Average Permian daily gas production (Mcf/day)	650(a)	—	N/A
Average south Texas daily gas production (Mcf/day)	3,602(b)	—	N/A
Average Vanguard daily gas production (Mcf/day)	14,029	11,080	
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$10.40(c)	$8.92(c)	17%
Net realized gas price, excluding hedges	$10.30	$8.04	28%
Net Oil Production:			
Appalachian oil (Bbls)	48,977	30,629	60%
Permian oil (Bbls)	212,599(a)	—	N/A
Total oil (Bbls)	261,576	30,629	
Average Appalachian daily oil production (Bbls/day)	134	84	60%
Average Permian daily oil production (Bbls/day)	635(a)	—	N/A
Average Vanguard daily oil production (Bbls/day)	769	84	
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$85.69	$66.08	30%
Net realized oil price, excluding hedges	$91.48	$66.08	38%

(a) The Permian acquisition closed on January 31, 2008 and, as such, only eleven months of operations are included in the year ended December 31, 2008 and were not included in the operations of 2007.

(b) The south Texas acquisition closed on July 28, 2008 and, as such, only five months of operations are included in the year ended December 31, 2008 and were not included in the operations of 2007.

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

The increase in natural gas and oil sales was due primarily to the impact of the Permian Basin acquisition completed on January 31, 2008, the south Texas acquisition completed on July 28, 2008 and increases in commodity prices during the first three quarters of 2008. Production from the Permian Basin and south Texas acquisitions contributed $25.8 million of natural gas and oil sales for the year ended December 31, 2008. In Appalachia, a 12% decline in natural gas production was partially offset by a 60% increase in oil production for a net production decline of 9% on an Mcfe basis. The 60% increase in oil production was primarily due to a greater focus on the completion of oil zones as prices increased which conversely affected the amount of natural gas produced. However, the negative impact of the natural gas production decline was offset by a 28% increase in the average realized natural gas sales price received (excluding hedges) and a 38% increase in the average realized oil price (excluding hedges).

Hedging and Price Risk Management Activities

During the year ended December 31, 2008, the Company recognized $0.3 million and $32.5 million related to gains on commodity cash flow hedges and gains on other commodity derivative contracts, respectively. These amounts relate to derivative contracts that the Company entered into in order to mitigate commodity price exposure on a portion of our expected production. On November 10, 2008, the Company concluded that since January 1, 2008 the contemporaneous formal documentation it had prepared to support its initial hedge designations and subsequent assessments for ineffectiveness in connection with the Company's natural gas and oil hedging program in 2008 had not met the technical requirements to qualify for cash flow hedge accounting treatment in accordance with SFAS 133 and it discontinued hedge accounting effective January 1, 2008. The gain on commodity cash flow hedges relates to the amount that settled in 2008 and has been reclassified to earnings from accumulated other comprehensive loss. The gain on other commodity derivative contracts relates to the change in fair value of derivative contracts no longer accounted for under cash flow hedge accounting.

Costs and Expenses

Production costs consist of the lease operating expenses and production and other taxes (severance and ad valorem taxes). Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses in Appalachia also include a $60 per month per well administrative charge pursuant to a management services agreement with Vinland, 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, paid to Vinland pursuant to a gathering and compression agreement with Vinland. Lease operating expenses increased by $6.0 million to $11.1 million for the year ended December 31, 2008 as compared to the year months ended December 31, 2007 of which $4.8 million related to the Permian Basin and south Texas acquisitions. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $2.9 million for the year ended December 31, 2008 as compared to the same period in 2007 of which $2.0 million related to the Permian Basin and south Texas acquisitions, and the remaining increase is attributable to higher severance taxes resulting from increased revenues in Appalachia.

Depreciation, depletion, amortization and accretion increased to approximately $14.9 million for the year ended December 31, 2008 from approximately $9.0 million for the year ended December 31, 2007 due primarily to the additional depletion recorded on the oil and gas properties acquired in the Permian Basin and south Texas acquisitions.

An impairment of natural gas and oil properties in the amount of $58.9 million was recognized during the year ended December 31, 2008 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 and oil prices at the measurement date. 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 year ended December 31, 2008 increased $3.2 million as compared to the year ended December 31, 2007. For the years ended December 31, 2008 and 2007 these expenses included a $3.6 million and $2.1million non-cash compensation charge related to the grant of restricted

Class B units to officers and an employee, the grant of unit options to management, and the grant of common units to board members during 2007 and 2008. The remaining increase of $1.7 million during the year ended December 31, 2008 as compared to the same period in 2007 is principally due to incremental costs associated with being a public company.

Interest expense declined to $5.5 million for the year ended December 31, 2008 compared to $8.1 million for the year ended December 31, 2007 primarily due to lower interest rates which more than offset the higher average outstanding debt for the year ended December 31, 2008. All of our Predecessor's outstanding debt was repaid with borrowings under our reserve-based credit facility in January 2007, including an early prepayment penalty of $2.5 million.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues

Natural gas and oil sales decreased to approximately $34.5 million for the year ended December 31, 2007 from approximately $38.2 million for the year ended December 31, 2006. The key revenue measurements were as follows:

	Year Ended December 31,		
	Vanguard 2007	Vanguard Predecessor 2006	Percentage Increase (Decrease)
Total natural gas production (MMcf)	4,044	4,182	(3)%
Average Vanguard daily gas production (Mcf/day)	11,080	11,457	(3)%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$8.92(a)	$8.00	12%
Net realized gas price, excluding hedges	$8.04	$8.68	(7)%
Total oil production (Bbls)	30,629	32,718	(6)%
Average Vanguard daily oil production (Bbls/day)	84	90	(6)%
Average Oil Sales Price per Bbl, including and excluding hedges	$66.08	$57.40	15%

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

The decrease in natural gas and oil sales was primarily due to the 3% decrease in natural gas production and the 6% decrease in oil production. Additionally, contributing to the decrease in natural gas and oil sales was the 7% decrease in the average realized gas price during the year ended December 31, 2007 over December 31, 2006. However, the negative impact of the production decline was offset by a 15% increase in the average realized oil price. The decrease in production can be attributed to our drilling 83 wells during the 2007 as compared to the Predecessor drilling 100 wells in the same period in 2006.

Hedging and Price Risk Management Activities

During the year ended December 31, 2007, we hedged approximately 88% of our natural gas production, which resulted in reported revenues that were approximately $0.7 million lower than we would have achieved at unhedged prices. However, the actual cash impact of the hedges increased realizations by $4.3 million for the period after excluding the premiums paid on the settled derivatives. In addition, in January 2007, we terminated existing natural gas swaps at a cost of approximately $2.8 million which resulted in an additional realized loss on derivative contracts of approximately $0.8 million during the year ended December 31, 2007. During the year ended December 31, 2006, our Predecessor hedged approximately 53% of our natural gas production, which resulted in revenues that were approximately $2.2 million lower than our Predecessor would have achieved at unhedged prices. The derivative contracts entered into in 2006 were not specifically designated as hedges under SFAS 133 and therefore did not qualify for hedge accounting treatment. As a result, the change in the fair value of these natural gas derivative contracts was marked to market in earnings each period in 2006 and resulted in a $17.7 million non-cash gain for the year ended December 31, 2006.

Costs and Expenses

Production costs consist of the lease operating expenses and production and other taxes (severance and ad valorem taxes). Lease operating expenses includes third-party transportation costs, operating and maintenance costs associated with our gathering systems (which were conveyed to Vinland in connection with the Restructuring) and other customary charges. As a result of the Restructuring, lease operating expenses for the year ended December 31, 2007 includes third-party transportation costs, a $60 per month per well administrative charge pursuant to a management services agreement with Vinland, a $0.25 per Mcf and $0.55 per Mcf gathering and compression charge for production from wells drilled pre and post January 5, 2007, respectively, paid to Vinland pursuant to a gathering and compression agreement with Vinland, as well as other customary charges. Lease operating expenses increased only slightly to $5.1 million for the year ended December 31, 2007 as compared to $4.9 million for the year ended December 31, 2006 due primarily to amounts paid to Vinland under the management services agreement and gathering and compression agreement being comparable to our actual costs incurred for the same period in 2006. On a per Mcfe basis, lease operating expenses increased by 7% to $1.20 for the year ended December 31, 2007 compared to $1.12 for the same period in 2006. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state and county and are based on the value of our reserves. Production and other taxes increased $0.3 million to $2.1 million or 20% on a per Mcfe basis, for the year ended December 31, 2007 as compared to the year ended December 31, 2006. This increase was principally due to a $0.2 million underaccrual of severance taxes in 2006, which was charged to expense in the first quarter of 2007.

Depreciation, depletion, amortization and accretion increased $0.3 million to $8.9 million for the year ended December 31, 2007 despite the conveyance of certain assets to Vinland pursuant to the Restructuring effective January 2007. This result occurred due to the conveyance of long-lived depreciable assets which generated little associated depreciation and the conveyed value of the 60% interest in proved undeveloped properties which was largely offset by the cost of new wells drilled since December 31, 2006. In addition, the increase in depletion can be attributed to upward revisions of future drilling costs in the 2007 reserve report which increased the full cost pool to be depleted.

Selling, general and administrative expenses include the cost of our employees and executive officers, related benefits, office leases, professional fees and other costs associated with being a public company not directly resulting from field operations. These expenses for the year ended December 31, 2007 decreased $1.7 million to $3.5 million as compared to $5.2 million for the year ended December 31, 2006 primarily due to the impact of the Restructuring which transferred all of the employees, except two of its officers to Vinland. The decrease in selling, general and administrative expenses during the year ended December 31, 2007 as compared to 2006 was offset by two principal factors. First, our Predecessor capitalized $3.9 million of internal costs under the full cost method of accounting for natural gas and oil properties for the year ended December 31, 2006 whereas we have not capitalized any internal costs in 2007, respectively. Second, the year ended December 31, 2007 includes a $2.1 million non-cash compensation charge related to the grant of Class B units to management, an employee and a board member in April, August and October 2007.

Bad debt expense of approximately $1.0 million was recorded during the year ended December 31, 2007 as a result of a provision for a loss on the entire amount due from a customer which filed for protection under Chapter 11 of the Bankruptcy Code in May 2007. The account receivable was due from oil sales through December 2006 at which time we ceased selling oil to the customer. As the amount of any potential recovery is uncertain, we elected to reserve the entire balance. We began selling our oil production to a new customer beginning March 2007.

Interest and financing expenses were approximately $8.1 million for the year ended December 31, 2007 compared to approximately $7.3 million for the year ended December 31, 2006. The increase in 2007 is primarily due to increased debt levels associated with drilling additional wells and rising interest rates. In addition, our interest rates during 2007 were directly affected by the provision in our credit facility which increased our rates by 1% on LIBOR loans effective July 1, 2007 until we completed our IPO in October 2007.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We have discussed the development, selection and disclosure of each of these with our audit committee. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. Please read *Note 1* to the Notes to the Consolidated Financial Statements included in item 8 of this Annual Report on Form 10-K for a discussion of additional accounting policies and estimates made by management.

Full-Cost Method of Accounting for Natural Gas and Oil Properties

The accounting for our business is subject to special accounting rules that are unique to the natural gas and oil industry. There are two allowable methods of accounting for gas and oil business activities: the successful-efforts method and the full-cost method. There are several significant differences between these methods. Under the successful-efforts method, costs such as geological and geophysical (G&G), exploratory dry holes and delay rentals are expensed as incurred, where under the full-cost method these types of charges would be capitalized to the full-cost pool. In the measurement of impairment of gas and oil properties, the successful-efforts method of accounting follows the guidance provided in Statement of Financial Accounting Standards (SFAS) No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* where the first measurement for impairment is to compare the net book value of the related asset to its undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method, the net book value (full-cost pool) is compared to the future net cash flows discounted at 10% using commodity prices in effect on the last day of the reporting period (ceiling limitation). If the full-cost pool is in excess of the ceiling limitation, the excess amount is charged through income.

We have elected to use the full-cost method to account for our investment in natural gas and oil properties. Under this method, we capitalize all acquisition, exploration and development costs for the purpose of finding natural gas and oil reserves, including salaries, benefits and other internal costs directly related to these finding activities. For the years ended December 31, 2008 and 2007, there were no internal costs capitalized. For the year ended December 31, 2006 such internal costs capitalized totaled $3.9 million. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. In addition, gains or losses on the sale or other disposition of natural gas and oil
properties are not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Our results of operations would have been different had we used the successful-efforts method for our natural gas and oil investments. Generally, the application of the full-cost method of accounting results in higher capitalized costs and higher depletion rates compared to similar companies applying the successful-efforts method of accounting.

Full-Cost Ceiling Test

At the end of each quarterly reporting period, the unamortized cost of natural gas and oil properties is limited to the sum of the estimated future net revenues from proved properties using period-end prices, after giving effect to cash flow hedge positions, for which hedge accounting is applied, discounted at 10% and the lower of cost or fair value of unproved properties ("Ceiling Test").

The calculation of the Ceiling Test and the provision for depletion and amortization are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development as more fully discussed in "Natural Gas and Oil Reserve Quantities" below. Due to the imprecision in estimating natural gas and oil reserves as well as the potential volatility in natural gas and oil prices and their effect on the carrying value of our proved natural gas and oil reserves, there can be no assurance that additional Ceiling Test write downs in the future will not be required as a result of factors that may negatively affect the present value of proved natural gas and oil properties. These factors include declining natural gas and oil prices, downward revisions in estimated proved natural gas and oil reserve quantities and unsuccessful drilling activities. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. This impairment was calculated based on prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil. No ceiling test impairment was required during 2007 or 2006.

Asset Retirement Obligation

We have obligations to remove tangible equipment and restore land at the end of a natural gas or oil well's life. Our removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future plugging and abandonment costs requires management to make estimates and judgments inherent in the present value calculation of the future obligation. These include ultimate plugging and abandonment costs, inflation factors, credit adjusted discount rates, and timing of the obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the natural gas and oil property balance.

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of natural gas and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI prepares a reserve and economic evaluation of all our properties on a well-by-well basis.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare our reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing their reserve reports. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas, natural gas liquids and oil eventually recovered.

Revenue Recognition

Sales of natural gas and oil are recognized when natural gas and oil have been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. We sell natural gas and oil on a monthly basis. Virtually all of our contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the natural gas or oil, and prevailing supply and demand conditions, so that the price of the natural gas and oil fluctuates to remain competitive with other available natural gas and oil supplies. As a result, our revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase without consideration of hedging. We believe that the pricing provisions of our natural gas and oil contracts are customary in the industry.

Gas imbalances occur when we sell more or less than our entitled ownership percentage of total gas production. Any amount received in excess of our share is treated as a liability. If we receive less than our entitled share the underproduction is recorded as a receivable. We did not have any significant gas imbalance positions at December 31, 2008 or 2007.

Price Risk Management Activities

We periodically use derivative financial instruments to achieve a more predictable cash flow from our natural gas and oil production by reducing our exposure to price fluctuations. Currently, these derivative financial instruments include fixed-price swaps, collars and put options. The derivative instruments we established in 2007 were designated as hedges under SFAS 133. In connection with preparing its quarterly report for third quarter 2008 and discussion with BDO Seidman, LLP, the Company's new independent registered public accounting firm, management of the Company and the Audit Committee of its Board of Directors concluded that the contemporaneous formal documentation it had prepared to support its initial hedge designations and subsequent assessments for ineffectiveness in connection with the Company's natural gas and oil hedging program in 2008 did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with SFAS 133. The primary reasons for this determination were that the formal hedge documentation lacked specificity of the hedged cash flow and the quantitative subsequent assessments for ineffectiveness were insufficient. Therefore, the cash flow designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. In addition, the natural gas derivative swap contracts entered into in 2007 were de-designated as cash flow hedges in the first quarter of 2008 due to an overhedged position in natural gas which made them ineffective.

Under SFAS 133, the fair value of hedge contracts is recognized in the Consolidated Balance Sheets as an asset or liability, and the change in fair value of the hedge contracts are reflected in earnings. If the hedge contracts qualify for hedge accounting treatment, the fair value of the hedge contract is recorded in "accumulated other comprehensive income," and changes in the fair value do not affect net income until the contract is settled. If the hedge contract does not qualify for hedge accounting treatment, the change in the fair value of the hedge contract is reflected in earnings during the period as gain or loss on other commodity derivatives. Under the cash flow hedge accounting treatment used by the Company in 2007, the fair values of the hedge contracts were recognized in the consolidated balance sheets with the resulting unrealized gain or loss recorded initially in accumulated other comprehensive income and later reclassified through earnings when the hedged production affected earnings. As a result of the determination that the documentation failed to meet cash flow hedge accounting treatment, the unrealized gain or loss on other commodity derivatives was recorded in the consolidated statements of operations as a component of revenues in 2008. In addition, the net derivative loss at December 31, 2007 related to the de-designated natural gas derivative contracts entered into in 2007 is reported in accumulated other comprehensive income until the month in which the transactions settle.

Our Predecessor did not specifically designate the derivative instruments established in 2006 as hedges under SFAS 133, even though they protected our Predecessor from changes in commodity prices. Therefore, the mark to market of these instruments was recorded in current earnings as a component of total revenues. Further, these mark to market amounts represent non-cash charges. Had no hedges been in place, our Predecessor would have received additional revenue of $2.2 million during 2006. In January 2007, we terminated existing hedges at a cost of approximately $2.8 million, of which $0.8 million is reflected as a realized loss on commodity cash flow hedges on the statement of operations for the year ended December 31, 2007.

Stock Based Compensation

We account for Stock Based Compensation pursuant to SFAS No. 123(R)— *Share-Based Payment* ("SFAS 123(R)"). SFAS 123(R) requires an entity to recognize the grant-date fair-value of stock options and other equity-based compensation issued to employees in the income statement and eliminates the alternative to use the intrinsic value method of accounting that was provided in SFAS 123, which generally resulted in no compensation expense recorded in the financial statements related to the issuance of equity awards to employees. It establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires all companies to apply a fair-value-based measurement method in accounting for generally all share-based payment transactions with employees. On March 29, 2005, the SEC staff issued SAB No. 107, Share-Based Payment, to express the views of the staff regarding the interaction between SFAS 123(R) and certain SEC rules and regulations and to provide the staff's views regarding the valuation of share-based payment arrangements for public companies.

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 will vest 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.

Furthermore, on March 27, 2008, phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2008 and the amount to be paid was equal to the appreciation in value of the units, if any, from the date of the grant until the determination date (December 31, 2008), plus cash distributions paid on the units, less an 8% hurdle rate. These phantom units expired on December 31, 2008 and no liability or expense was recognized as there was no appreciation in the value of these units.

In January 2009, new phantom units were granted to two officers equal to 1% of our units outstanding at January 1, 2009, subject to the same terms as the 2008 phantom units. Additionally, in January 2009, four board members were each granted 5,000 common 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 are subject to accounting for these grants under SFAS 123(R), *Share-Based Payment*. With respect to the 420,000 restricted Class B units granted, we expect to incur $2.2 million and $0.1 million in non-cash compensation expense for the years 2009 and 2010, respectively. For the years ended December 31, 2008 and 2007, we recorded $3.6 million and $2.1 million of non-cash compensation expense, respectively. Non-cash compensation expense to be incurred on the 40,000 Class B units to be issued in the future will be determined based on the trading price of the units when they are granted.

Recently Adopted Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 157 "*Fair Value Measurements*" ("SFAS 157"). SFAS 157 introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. On February 6, 2008, the FASB issued a final FASB Staff Position ("FSP") No. FAS 157-b, "*Effective Date of FASB Statement No. 157.*" This FSP delays 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 a recurring basis. In addition, the FSP removes certain leasing transactions from the scope of SFAS 157. The effective date of SFAS 157 for non-financial assets and non-financial liabilities has been delayed by one year to fiscal years beginning after November 15, 2008 and interim periods within those fiscal years. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007, and the Company prospectively adopted the standard for those assets and liabilities as of January 1, 2008. In adopting SFAS 157, the Company determined that the impact of these additional assumptions on fair value measurements did not have a material effect on financial position or results of operations. The Company is still assessing the potential impact of implementation in 2009 of those portions of the guidance for which the effective date has been deferred by the FASB.

In February 2007, the FASB issued SFAS No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115*" ("SFAS 159"), which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of SFAS 159 is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of SFAS 159 apply only to entities that elect to use the fair value option. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Effective January 1, 2008, the Company adopted SFAS 159. Because the Company did not elect to apply the provisions of SFAS 159 to any eligible financial instrument, the adoption did not affect the consolidated financial statements.

New Pronouncements Issued But Not Yet Adopted

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *"Business Combinations"* ("SFAS 141(R)"), which replaces FASB Statement No. 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, which will be our fiscal year 2009. The impact, if any, on the consolidated financial statements will depend on the nature and size of business combinations that we consummate after the effective date.

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, which will be our fiscal year 2009. Based upon the December 31, 2008 balance sheet, SFAS 160 would have no impact on the 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, with early application encouraged. We are currently evaluating the impact of adopting SFAS 161 on our consolidated financial statements.

In December 2008, the 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: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) 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. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on its disclosures, financial position or results of operations.

Capital Resources and Liquidity

Disruption to Functioning of Capital Markets

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to issue debt and equity on favorable terms will be limited as long as the capital markets remain constrained. We intend to move forward with our development drilling program when market conditions allow for an adequate return on a 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, 2008 and December 31, 2008 ranged from a high of $145.29 to a low of $33.87 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2008 to December 31, 2008 ranged from a high of $13.58 to a low of $5.29. As of March 5, 2009, the NYMEX crude oil spot price per barrel was $43.61and the NYMEX natural gas spot price per MMBtu was $4.09.

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, as a result of our IPO, 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 or acquiring additional reserves. We expect to fund our 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 March 5, 2009, we have $37.0 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. In October 2008, our borrowing base was set at $175.0 million. Our next borrowing base redetermination is scheduled for April 2009 utilizing our December 31, 2008 reserve report. Based on the current commodity price environment, banks have lowered their internal projections of future natural gas and oil prices which will decrease the borrowing base and thus decrease the amount available to be borrowed under our reserve-based credit facility. However, based on preliminary discussions with our lead bank, due to our favorable hedging contracts, we anticipate that the reduction would not be material to the borrowing base as a whole and would not inhibit our ability to make distributions to our unitholders. 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 decreases in our borrowing base availability in the future. As a result, to the extent available after unitholder distributions, debt service, and capital expenditures, it is our current intention to utilize our excess cash flow during 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.

Cash Flow from Operations

Net cash provided by operating activities was $39.6 million during the year ended December 31, 2008, compared to $1.4 million during the year ended December 31, 2007 and $16.1 million during the year ended December 31, 2006. The increase in cash provided by operating activities during the year ended December 31, 2008 was substantially due to increased income, after adjusting for non-cash items, generated from increased production related to acquisitions and higher average realized prices, a decrease in cash used in price risk management activities and an increase in accounts payable accrued expenses, offset by an increase in accounts receivable. The cash used in operating activities during the year ended December 31, 2007 included the termination of existing natural gas swaps at a cost of approximately $2.8 million, cash paid on early extinguishment of debt of approximately $2.5 million, the payment of $6.5 million for put option derivative contracts, and the payment of $7.5 million of premiums to reset derivative strike prices at a higher value.

Our 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 and political 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 of natural gas and oil. 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. Please read "Item 1—Operations—Price Risk Management Activities" and "Item 7A—Quantitative and Qualitative Disclosures About Market Risk" for details about derivatives in place through 2012.

Investing Activities—Acquisitions and Capital Expenditures

Our capital expenditures were $119.5 million in the year ended December 31, 2008, and $26.4 million and $37.4 million for the years ended December 31, 2007 and 2006, respectively. The increase in cash used in investing activities was primarily attributable to $100.7 million used for the acquisition of natural gas and oil properties in the Permian Basin and south Texas. In addition, the total for the year ended December 31, 2008 includes $18.2 million for the drilling and development of natural gas and oil properties as compared to $12.8 million for the year ended December 31, 2007. The total for 2007 includes $3.6 million for acquisitions of natural gas and oil properties and $9.8 million for deposits on acquisition of and prepayments of natural gas and oil properties. There were no acquisitions during 2006. The totals for 2006 include $28.9 million for drilling and development of natural gas properties, and $8.5 million for furniture, fixtures and equipment, respectively, which includes expenditures for extensions of the gathering system and related midstream activities. The furniture, fixtures and equipment were retained by our Predecessor in the Restructuring.

Excluding any potential acquisitions, we currently anticipate a capital budget for 2009 of between $6.0 million and $6.5 million, which predominantly consists of recompletions and workovers of existing wells and a limited amount of new drilling in south Texas in the second half of 2009. This capital budget is expected to be funded through cash from operations. As of March 5, 2009, we had

$37.0 million available for borrowing under our reserve-based credit facility. Our current borrowing base is $175.0 million. Our next borrowing base redetermination is scheduled for April 2009 utilizing our December 31, 2008 reserve report. Based on the current commodity price environment, banks have lowered their internal projections of future natural gas and oil prices which will decrease the borrowing base and thus decrease the amount available to be borrowed under our reserve-based credit facility. However, based on preliminary discussions with our lead bank, due to our favorable hedging contracts, we anticipate that the reduction would not be material to the borrowing base as a whole. 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 decreases in our borrowing base availability in the future. We anticipate that our cash flow from operations and available borrowing capacity under our reserve-based credit facility will exceed our planned capital expenditures and other cash requirements for the year ended December 31, 2009. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Financing Activities

Cash provided by financing activities was approximately $76.9 million for the year ended December 31, 2008, compared to $26.4 million for the year ended December 31, 2007. During the year ended December 31, 2008, total proceeds from borrowings under our reserve-based credit facility, net of repayments were $97.6 million which were used to fund the Permian Basin and south Texas acquisitions. During the year ended December 31, 2007, total proceeds from borrowings under our reserve-based credit facility were $126.2 million, which were principally used to pay off our Predecessor's outstanding borrowings. Additionally, during the year ended December 31, 2007, we completed a private equity offering for $41.2 million and used the net proceeds of this private equity offering to make a distribution to Majeed S. Nami, VNR's sole member at that time.

Available Credit

Credit markets in the United States and around the world remain constrained due to a lack of liquidity and confidence in a number of financial institutions. Investors continue to seek perceived safe investments in securities of the United States government rather than individual entities. We may experience difficulty accessing the long-term credit markets due to prevailing market conditions. Additionally, existing constraints in the credit markets may increase the rates we are charged for utilizing these markets. Notwithstanding the continuing weakness in the United States credit markets, we expect that our available liquidity is sufficient to meet our operating and capital requirements into 2009.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. Our reserve-based credit facility was amended and restated in February 2008 to extend the maturity date from January 2011 to March 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and the Bank of Nova Scotia. The increase in the borrowing base was principally the result of inclusion of the reserves related to the Permian Basin acquisition in January 2008. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. As of October 22, 2008, our reserve-based credit facility was amended and restated to increase the borrowing base to $175.0 million and add one lender, 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. At December 31, 2008, we had $135.0 million outstanding under our reserve-based credit facility and as of March 5, 2009, we have $37.0 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. In October 2008, our borrowing base was set at $175.0 million. Our next borrowing base redetermination is scheduled for April 2009 utilizing our December 31, 2008 reserve report. Based on the current commodity price environment, banks have lowered their internal projections of future natural gas and oil prices which will decrease the borrowing base and thus decrease the amount available to be borrowed under our reserve-based credit facility. However, based on preliminary discussions with our lead bank, due to our favorable hedging contracts, we anticipate that the reduction would not be material to the borrowing base as a whole. 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 decreases in our borrowing base availability in the future. As a result, absent accretive acquisitions, it is our current intention to utilize our excess cash flow during 2009 to reduce our borrowings under our reserve-based credit facility.

Borrowings under the reserve-based credit facility are available for 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 December 31, 2008, 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, impairment, changes in fair value of derivative instruments and other similar charges, minus all non-cash income added to consolidated net income, the aggregate amount of cash used to purchase our own units during the preceding twelve months 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;
- consolidated debt to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, accretion, impairment, 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 and if the amount of borrowings outstanding under our reserve-based credit facility is less than 90% of the borrowing base.

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

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

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

Off-Balance Sheet Arrangements

We have no guarantees or off-balance-sheet debt to third parties, and we maintain no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Contingencies

The Company regularly analyzes current information and accrues 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 December 31, 2008, there were no material loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of December 31, 2008 is provided in the following table.

	Payments Due by Year (in thousands)						
	2009	2010	2011	2012	2013	After 2013	Total
Management compensation	$ 600	$ 100	$ —	$ —	$ —	$ —	$ 700
Asset retirement obligations	—	37	183	32	14	1,868	2,134
Derivative liabilities	677	1,225	1,445	1,102	292	—	4,741
Long-term debt (1)	—	—	135,000	—	—	—	135,000
Operating leases (2)	154	41	—	—	—	—	195
Total	$ 1,431	$ 1,403	$ 136,628	$ 1,134	$ 306	$ 1,868	$ 142,770

(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.

(2) Includes lease agreement entered into in February 2009 which expires in April 2010.

ITEM 7A. 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 prices for natural gas production and the West Texas Intermediate Light Sweet price for oil production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside our control. In addition, the potential exists that if commodity prices decline to a certain level, the borrowing base can be decreased at the borrowing base redetermination date to an amount lower than the amount of debt currently outstanding and, because it would be uneconomical, production could decline to levels below our hedged volumes.

Furthermore, the risk that we will be required to write down the carrying value of our natural gas and oil properties increases when oil and gas prices are low or volatile. In addition, write downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase. For example, natural gas and oil prices declined significantly throughout the second half of 2008. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. This impairment was calculated based on prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil. Additionally, if natural gas prices decline by $1.00 per MMBtu or 18% and oil prices declined by $6.00 per barrel or 15%, the standardized measure of our proved reserves as of December 31, 2008 would decrease from $190.1 million to $138.1 million, based on price sensitivity generated from an internal evaluation.

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 and option premium, equal to the fair value of the option 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 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 December 31, 2008, the fair value of commodity derivative contracts was an asset of approximately $37.9 million, of which $22.2 million settle during the next twelve months. A 10% increase in the gas and oil index price above the December 31, 2008 price would result in a decrease in the fair value of all of our commodity derivative contracts of approximately $5.3 million; conversely, a 10% decrease in the gas and oil index price would result in an increase of approximately $5.4 million.

The following table summarizes commodity derivative contracts in place at December 31, 2008:

	2009	2010	2011	2012
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	3,629,946	3,236,040	2,962,312	—
Fixed Price ($/MMBtu)	$ 9.42	$ 9.10	$ 7.82	$ —
Puts:				
Notional Volume (MMBtu)	840,143	—	—	—
Floor Price ($/MMBtu)	$ 7.50	$ —	$ —	$ —
Collars:				
Notional Volume (MMBtu)	1,000,000	730,000	—	—
Floor Price ($/MMBtu)	$ 7.50	$ 8.00	$ —	$ —
Ceiling Price ($/MMBtu)	$ 9.00	$ 9.30	$ —	$ —
Total:				
Notional Volume (MMBtu)	5,470,089	3,966,040	2,962,312	—

Oil Positions:				
Fixed Price Swaps:				
Notional Volume (Bbls)	181,500	164,250	151,250	144,000
Fixed Price ($/Bbl)	$ 87.23	$ 85.65	$ 85.50	$ 80.00
Collars:				
Notional Volume (Bbls)	36,500	—	—	—
Floor Price ($/Bbl)	$ 100.00	$ —	$ —	$ —
Ceiling Price ($/Bbl)	$ 127.00	$ —	$ —	$ —
Total:				
Notional Volume (Bbls)	218,000	164,250	151,250	144,000

In February 2009, we liquidated our 2012 oil swap and entered into new 2010 and 2011 natural gas swap and collar transactions. Specifically, an $8.04 and $7.85 fixed price NYMEX natural gas swap for January through September 2010 and April through September 2011, 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 set at prices above the current market by using the proceeds of the liquidation of the 2012 oil swap.

Interest Rate Risks

At December 31, 2008, we had debt outstanding of $135.0 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 $0.4 million increase in annual interest expense after consideration of the interest rate swaps discussed below. In December 2007 and during 2008, 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, the company reduced its borrowing cost 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, the company 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, the Company recorded changes in the fair value of its interest rate derivatives in current earnings under 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.

The following summarizes information concerning our positions in open interest rate swaps at December 31, 2008.

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data.

All schedules are omitted as the required information is not applicable or the information is presented in the Consolidated Financial Statements and related notes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Members
Vanguard Natural Resources, LLC
Houston, Texas

We have audited the accompanying consolidated balance sheet of Vanguard Natural Resources, LLC as of December 31, 2008 and the related consolidated statements of operations, comprehensive income (loss), members' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Vanguard Natural Resources, LLC at December 31, 2008, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Vanguard Natural Resources, LLC's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 10, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Houston, Texas
March 10, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of
Vanguard Natural Resources, LLC
and Subsidiaries

We have audited the accompanying consolidated balance sheet of Vanguard Natural Resources, LLC (a Delaware limited liability company) and subsidiaries (the “Company”) as of December 31, 2007, and the related consolidated statements of operations, members’ equity, comprehensive income and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Vanguard Natural Resources, LLC and subsidiaries as of December 31, 2007, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
March 31, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of
Vanguard Natural Gas, LLC
and Subsidiaries

We have audited the accompanying consolidated statements of operations and cash flows of Vanguard Natural Gas, LLC (formerly Nami Holding Company, LLC), and subsidiaries (the “Company”) for the year ended December 31, 2006. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Vanguard Natural Gas, LLC and subsidiaries for the year ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
April 20, 2007

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Operations
For the Years Ended December 31,

	Vanguard		Vanguard Predecessor
	2008	2007	2006
Revenues			
Natural gas and oil sales	$ 68,850,004	$ 34,540,500	$ 38,849,142
Gain (loss) on commodity cash flow hedges	269,260	(701,675)	—
Gain on other commodity derivative contracts	32,476,472	—	15,539,915
Total revenues	101,595,736	33,838,825	54,389,057
Costs and expenses			
Lease operating expenses	11,111,849	5,066,230	4,896,327
Depreciation, depletion, amortization and accretion	14,910,454	8,981,179	8,633,235
Impairment of natural gas and oil properties	58,886,660	—	—
Selling, general and administrative expenses	6,715,036	3,506,539	5,198,760
Bad debt expense	—	1,007,458	—
Production and other taxes	4,964,987	2,053,604	1,774,215
Total costs and expenses	96,588,986	20,615,010	20,502,537
Income from operations	5,006,750	13,223,815	33,886,520
Other income (expense)			
Interest income	17,232	61,621	40,256
Interest expense	(5,490,816)	(8,134,600)	(7,371,930)
Loss on interest rate derivative contracts	(3,284,514)	—	—
Loss on extinguishment of debt expense	—	(2,501,528)	—
Total other expense	(8,758,098)	(10,574,507)	(7,331,674)
Net income (loss)	$ (3,751,348)	$ 2,649,308	$ 26,554,846
Net income (loss) per unit:			
Common and Class B units - basic	$ (0.32)	$ 0.39	
Common and Class B units - diluted	$ (0.32)	$ 0.39	
Weighted average units outstanding:			
Common units – basic & diluted	11,374,473	6,533,411	
Class B units – basic & diluted	420,000	278,945	

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Balance Sheets
As of December 31,

	2008	2007
Assets		
Current assets		
Cash and cash equivalents	$ 2,616	$ 3,109,563
Trade accounts receivable, net	6,083,479	3,875,078
Derivative assets	22,183,648	4,017,085
Other receivables	2,762,730	497,653
Other currents assets	845,404	453,198
Total current assets	31,877,877	11,952,577
Property and equipment, net of accumulated depreciation	184,224	166,455
Natural gas and oil properties, at cost	284,446,984	135,435,240
Accumulated depletion, amortization and accretion	(102,178,304)	(28,451,891)
Natural gas and oil properties evaluated, net – full cost method	182,268,680	106,983,349
Other assets		
Derivative assets	15,748,721	1,329,511
Deferred financing costs	881,996	941,833
Non-current deposits	45,963	8,285,883
Other assets	1,554,416	1,519,577
Total assets	$232,561,877	$131,179,185
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 2,147,664	$ 1,056,627
Accounts payable – natural gas and oil	1,327,361	257,073
Payables to affiliates	2,554,624	3,838,328
Derivative liabilities	486,576	—
Accrued expenses	1,247,606	203,159
Total current liabilities	7,763,831	5,355,187
Long-term debt	135,000,000	37,400,000
Derivative liabilities	2,313,335	5,903,384
Asset retirement obligations	2,133,791	189,711
Total liabilities	147,210,957	48,848,282
Commitments and contingencies (Note 9)		
Members' equity		
Members' capital, 12,145,873 and 10,795,000 common units issued and outstanding at December 31, 2008 and 2007, respectively	88,550,178	90,257,856
Class B units, 420,000 issued and outstanding at December 31, 2008 and 2007	4,605,463	2,131,995
Accumulated other comprehensive loss	(7,804,721)	(10,058,948)
Total members' equity	85,350,920	82,330,903
Total liabilities and members' equity	$232,561,877	$131,179,185

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity
For the Years Ended December 31, 2008 and 2007

	Common Units	Class B Units	Total Members' Equity
Balance, January 1, 2007	—	—	$ —
Initial contribution	5,540,000	—	3,289,055
Sale of private placement units	—	—	41,220,000
Distribution to member	—	—	(41,220,000)
Issuance of common units, net of offering costs of $9,804,085	5,250,000	—	89,945,916
Distribution to members	—	—	(5,626,423)
Unit-based compensation	5,000	420,000	2,131,995
Net income	—	—	2,649,308
Changes in fair value of cash flow hedges	—	—	(10,058,948)
Balance, December 31, 2007	10,795,000	420,000	$ 82,330,903
Distribution to members ($0.291, $0.445, $0.445 and $0.50 per unit to unit holders of record on February 7, 2008, April 30, 2008, July 31, 2008 and October 31, 2008, respectively)	—	—	(20,128,990)
Issuance of common units for acquisition of natural gas and oil properties, net of offering costs of $54,191	1,350,873	—	21,305,809
Unit-based compensation	—	—	3,340,319
Settlement of cash flow hedges in other comprehensive income	—	—	2,254,227
Net loss	—	—	(3,751,348)
Balance, December 31, 2008	12,145,873	420,000	$ 85,350,920

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Cash Flows
For the Years Ended December 31,

	Vanguard		Vanguard Predecessor
	2008	2007	2006
Operating activities			
Net income (loss)	$ (3,751,348)	$ 2,649,308	$ 26,554,846
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	14,910,454	8,981,179	8,633,235
Impairment of natural gas and oil properties	58,886,660	—	—
Amortization of deferred financing costs	362,400	296,115	—
Bad debt expense	—	1,007,458	—
Unit-based compensation	3,576,558	2,131,995	—
Amortization of premiums paid and non-cash settlements on derivative contracts	5,226,465	4,274,120	—
Unrealized gains on other commodity and interest rate derivative contracts	(35,851,133)	—	(17,747,817)
Changes in operating assets and liabilities:			
Trade accounts receivable	(2,208,401)	(504,683)	1,634,402
Payables to affiliates	(1,850,094)	(530,809)	(3,448,823)
Price risk management activities, net	(342,778)	(15,798,359)	—
Other receivables	(2,265,077)	—	1,004,464
Inventory	—	—	(54,988)
Other current assets	(344,940)	(340,060)	40,803
Accounts payable	2,161,325	1,243,817	373,381
Accrued expenses	1,044,447	(2,037,794)	(902,185)
Net cash provided by operating activities	39,554,538	1,372,287	16,087,318
Investing activities			
Additions to property and equipment	(74,053)	(132,371)	(8,486,055)
Additions to natural gas and oil properties	(18,174,285)	(12,821,192)	(28,896,671)
Acquisitions of natural gas and oil properties	(100,742,893)	(3,649,702)	—
Deposits and prepayments of natural gas and oil properties	(548,271)	(9,805,460)	—
Net cash used in investing activities	(119,539,502)	(26,408,725)	(37,382,726)
Financing activities			
Proceeds from borrowings	340,300,000	126,200,000	21,360,000
Repayment of debt	(242,700,000)	(182,867,500)	—
Proceeds from sale of initial public offering units, net	(54,191)	89,946,916	—
Proceeds from private placement units	—	41,220,000	—
Distributions to members	(20,128,990)	(46,846,423)	(1,375,104)
Financing costs	(302,563)	(1,237,948)	—
Purchase of units for issuance as unit-based compensation	(236,239)	—	—
Net cash provided by financing activities	76,878,017	26,415,045	19,984,896
Net increase (decrease) in cash and cash equivalents	(3,106,947)	1,378,607	(1,310,512)
Cash and cash equivalents, beginning of year	3,109,563	1,730,956	3,041,468
Cash and cash equivalents, end of year	$ 2,616	$ 3,109,563	$ 1,730,956
Supplemental cash flow information:			
Cash paid for interest	$ 5,039,665	$ 8,839,169	$ 7,233,549
Non-cash financing and investing activities:			
Asset retirement obligations	$ 1,882,397	$ 177,153	$ 187,638
Derivative assets assumed in acquisition of natural gas and oil properties	$ 2,467,573	$ —	$ —
Initial contribution of assets	$ —	$ 3,289,055	$ —
Issuance of common units for acquisition of natural gas and oil properties	$ 21,360,000	$ —	$ —
Transfer of deposit for acquisition of natural gas and oil properties	$ 7,830,000	$ —	$ —

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Other Comprehensive Income (Loss)
For the Years Ended December 31,

	Vanguard		Vanguard Predecessor
	2008	**2007**	**2006**
Net income (loss)	$ (3,751,348)	$ 2,649,308	$26,554,846
Net income (losses) from derivative contracts:			
Unrealized mark-to-market gains (losses) arising during the period	2,747,150	(9,644,224)	—
Reclassification adjustments for settlements	(492,923)	(414,724)	—
Other comprehensive income (loss)	2,254,227	(10,058,948)	—
Comprehensive income (loss)	$(1,497,121)	$ (7,409,640)	$26,554,846

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Notes to Consolidated Financial Statements
December 31, 2008

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 ("VNG"), Trust Energy Company, LLC ("TEC"), VNR Holdings, Inc. ("VNRH"), and Ariana Energy, LLC ("Ariana Energy") and Vanguard Permian, LLC ("Vanguard Permian") and (2) "Vanguard Predecessor," "Predecessor," "our operating subsidiary" or "VNG" are to Vanguard Natural Gas, LLC.

We were formed in October 2006 and 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, and 100% of our Predecessor's working interest in depths above and 100 feet below our known producing horizons. Vinland operates all of our existing wells in Appalachia and all of the wells that we drilled in Appalachia. We refer to these events as the "Restructuring."

In October 2007, we completed our initial public offering ("IPO") of 5.25 million units representing limited liability interests in VNR at $19.00 per unit for net proceeds of $92.8 million after deducting underwriting discounts and fees of $7.0 million. In addition, we incurred offering costs of $2.8 million in connection with the IPO. The proceeds were used to reduce indebtedness under our Credit Facility by $80.0 million and the balance was used for the payment of accrued distributions to pre-IPO unitholders and the payment of a deferred swap obligation.

1. Summary of Significant Accounting Policies

(a) Basis of Presentation and Principles of Consolidation:

The consolidated financial statements as of and for the years ended December 31, 2008 and 2007 include the accounts of VNR and its wholly owned subsidiaries. In conjunction with the Restructuring, Nami Resources Company, LLC conveyed its assets to Vinland or TEC as appropriate and as of January 5, 2007 is not a wholly-owned subsidiary of VNG and therefore is not consolidated in these consolidated financial statements. The consolidated financial statements as of and for the year ended December 31, 2006 are based on the annual audited financial statements of VNG prior to the Restructuring. As such, these periods are labeled Vanguard Predecessor and are separated from VNR financial data by a bold black line.

Our consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles and include the accounts of all subsidiaries after the elimination of all significant intercompany accounts and transactions. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or member's equity.

(b) Recently Adopted Accounting Pronouncements:

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 157 *"Fair Value Measurements"* ("SFAS 157"). SFAS 157 introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. On February 6, 2008, the FASB issued a final FASB Staff Position ("FSP") No. FAS 157-b, "Effective Date of FASB Statement No. 157." This FSP delays 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 a recurring basis. In addition, the FSP removes certain leasing transactions from the scope of SFAS 157. The effective date of SFAS 157 for non-financial assets and non-financial liabilities has been delayed by one year to fiscal years beginning after November 15, 2008 and interim periods within those fiscal years. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007, and the Company prospectively adopted the standard for those assets and liabilities as of January 1, 2008. In adopting SFAS 157, the Company determined that the impact of these additional assumptions on fair value measurements did not have a material effect on financial position or results of operations. The Company is still assessing the potential impact of implementation in 2009 of those portions of the guidance for which the effective date has been deferred by the FASB.

In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115"* ("SFAS 159"), which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of SFAS 159 is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of SFAS 159 apply only to entities that elect to use the fair value option. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Effective January 1, 2008, the Company adopted SFAS 159. Because the Company did not elect to apply the provisions of SFAS 159 to any eligible financial instrument, the adoption did not affect the consolidated financial statements.

(c) New Pronouncements Issued But Not Yet Adopted:

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *"Business Combinations"* ("SFAS 141(R)"), which replaces FASB Statement No. 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, which will be our fiscal year 2009. The impact, if any, on the consolidated financial statements will depend on the nature and size of business combinations that we consummate after the effective date.

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, which will be our fiscal year 2009. Based upon the December 31, 2008 balance sheet, SFAS 160 would have no impact on the 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, with early application encouraged. We are currently evaluating the impact of adopting SFAS161on our consolidated financial statements.

In December 2008, the Securities and Exchange Commission or "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: (*a*) report the independence and qualifications of its reserves preparer or auditor; (*b*) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and (*c*) 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. The Company has not yet determined the impact of this Final Rule, which will vary depending on changes in commodity prices, on its disclosures, financial position or results of operations.

(d) Cash Equivalents:

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents.

(e) Accounts Receivable and Allowance for Doubtful Accounts:

Accounts receivable are customer obligations due under normal trade terms and are presented on the consolidated balance sheets net of allowances for doubtful accounts. We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

(f) Inventory:

Materials, supplies and commodity inventories are valued at the lower of cost or market. The cost is determined using the first-in, first-out method. Inventories are included in other current assets in the accompanying consolidated balance sheets.

(g) Property and Equipment:

Property and equipment is recorded at cost. Major property additions, replacements and betterments are capitalized, while maintenance and repairs that do not extend the useful life of an asset are expensed as incurred. Depreciation is recorded using the straight-line method over the respective estimated useful lives of our assets.

The estimated useful lives of our property and equipment are as follows:

	Lives (Years)
Furniture and fixtures	3-5
Machinery and equipment	7

Depreciation expense for the years ended December 31, 2008 and 2007 was $56,283 and $36,539, respectively. Our Predecessor's consolidated statement of operations included depreciation expense in the amount of $693,266 for the year ended December 31, 2006.

(h) Natural Gas and Oil Properties:

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

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs on a quarterly basis. Specifically, costs are transferred to the amortizable base when properties are determined to have proved reserves. In addition, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory wells are determined to be unsuccessful. Additionally, the amortizable base includes estimated future development costs, dismantlement, restoration and abandonment costs net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with unevaluated properties or prospects in which we own a direct interest.

Capitalized costs are limited to a ceiling based on the present value of future net revenues using end of period spot prices discounted at 10%, plus the lower of cost or fair market value of unproved properties. If the ceiling is not greater than or equal to the total capitalized costs, we are required to write down capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write downs are included in the consolidated statements of operations as an impairment charge. Ceiling test calculations include the effects of the portion of natural gas and oil derivative contracts that have been recorded in other comprehensive income. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2008 of $58.9 million as a result of a decline in natural gas and oil prices at the measurement date. This impairment was calculated based on prices of $5.71 per MMBtu for natural gas and $41.00 per barrel of crude oil. No ceiling test impairment was required during 2007 or 2006.

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

(i) Asset Retirement Obligations:

Under SFAS No. 143, "*Accounting for Asset Retirement Obligations*," we record a liability for asset retirement obligations at fair value in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the assets useful life. Our recognized asset retirement obligation exclusively relates to the plugging and abandonment of natural gas and oil wells. Management periodically reviews the estimate of the timing of well abandonments as well as the estimated plugging and abandonment costs, which are discounted at the credit adjusted risk free rate. These retirement costs are recorded as a long-term liability on the consolidated balance sheet with an offsetting increase in natural gas and oil properties. An ongoing accretion expense is recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion, amortization and accretion expense in the consolidated statements of operations.

(j) Impairment of Long-Lived Assets:

We evaluate the carrying value of long-lived assets, other than investments in natural gas and oil properties, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. For property and equipment used in operations, the determination of impairment is based upon expectations of undiscounted future cash flows, before interest, of the related asset. If the carrying value of the asset exceeds the undiscounted future cash flows, the impairment would be computed as the difference between the carrying value of the asset and the fair value.

(k) Revenue Recognition and Gas Imbalances:

We apply the sales method of accounting for natural gas and oil revenue. Under this method, revenues are recognized based on the actual volume of natural gas and oil sold to customers, net of any royalty interests owed on the sold product. In the movement of natural gas, it is common for differences to arise between the volume of gas contracted or nominated, and the volume of gas actually received or delivered. These variances or imbalances, are the result of certain attributes of the natural gas commodity and the industry itself. Consequently, the credit given by a pipeline for volumes received from producers may be different than volumes actually delivered by a pipeline. When all necessary information, such as the final pipeline statement for receipts and deliveries are available, the imbalances are resolved and adjustments to the trade accounts receivable or trade accounts payable is recorded as appropriate. The amounts of imbalances were not material at December 31, 2008 and 2007.

(l) Concentration of Credit Risk:

Financial instruments that potentially subject us to concentrations of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative contracts. We control our exposure to credit risk associated with these instruments by (i) placing our assets and other financial interests with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include the evaluation of customers' financial condition and monitoring payment history, although we do not have collateral requirements and (iii) netting derivative assets and liabilities for counterparties where we have a legal right of offset.

At December 31, 2008 and 2007, the cash and cash equivalents are concentrated in three financial institutions. We periodically assess the financial condition of these institutions and believe that any possible credit risk is minimal.

The following purchasers accounted for 10% or more of the Company's natural gas and oil sales for the years ended December 31:

	2008	2007	2006
Seminole Energy Services	52%	—	—
North American Energy Corporation	—	41%	32%
Osram Sylvania, Inc.	15%	16%	13%
BP Energy Company	10%	11%	10%
Dominion Field Services, Inc.	—	13%	13%
Eagle Energy Partners, LLC	—	11%	7%

This concentration of customers may impact the overall exposure to credit risk in that the customers are in the energy industry and they may be similarly affected by changes in economic or other conditions.

(m) Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the Unites States of America 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.

(n) 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, the Company receives 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 in the period that the related production is delivered. 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 in the Consolidated Statements of Operations.

In connection with preparing our quarterly report for third quarter 2008 and discussion with BDO Seidman, LLP, the Company's new independent registered public accounting firm, management of the Company and the Audit Committee of its Board of Directors concluded that the contemporaneous formal documentation it had prepared to support its initial hedge designations and subsequent assessments for ineffectiveness in connection with the Company's natural gas and oil hedging program in 2008 did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with SFAS 133. The primary reasons for this determination were that the formal hedge documentation lacked specificity of the hedged cash flow and the quantitative subsequent assessments for ineffectiveness were insufficient. Therefore, the cash flow designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. In addition, the natural gas derivative swap contracts entered into in 2007 were de-designated as cash flow hedges in the first quarter of 2008 due to an overhedged position in natural gas which made them ineffective. As a result, the Company now recognizes changes in its derivatives' fair values in current earnings under gains (losses) on other commodity derivative contracts. In addition, the net derivative loss at December 31, 2007 related to the de-designated natural gas derivate swap contracts entered into in 2007 is reported in accumulated other comprehensive income until the month in which the transactions settle, at which time it is recognized as gains (losses) on commodity cash flow hedges.

(o) Income Taxes:

The Company is treated as a partnership for federal and state income tax purposes. As such, it is not a taxable entity and does not directly pay federal and state income tax. Its taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statements of operations, is included in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for the operations of the Company. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as the Company does not have access to information about each unitholders' tax attributes in the Company. However with respect to the Company, the Company's book basis in its net assets exceeded the Company's net tax basis by $54.7 million at December 31, 2008.

Legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the Revised Texas Franchise Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. The Company recorded a current tax liability of $0.1 million and a deferred tax liability of $0.2 million during the year ended December 31, 2008, respectively. The charges of $0.1 million and $0.2 million are included on our consolidated statements of operations for the year ended December 31, 2008, respectively, as a component of production and other taxes. The Company had no Texas sourced margin tax prior to 2008.

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. The purchase price included a payment of $7.8 million paid by us to the seller in December 2007 and this amount is reported in non-current deposits in our consolidated balance sheet at December 31, 2007. 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 $1.1million 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 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 years ended December 31, 2008 and 2007 show the effect on the Company's consolidated results of operations as if the January 2008 acquisition and July 2008 acquisition had occurred on January 1, 2008 and 2007. The pro forma results for the 2008 and 2007 periods presented are the results of combining the statement of operations for the Company 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) impairment of natural gas and oil properties, (4)interest expense on added borrowings necessary to finance the acquisition, and (5) 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:

	Year Ended December 31, 2008 Pro forma	2007 Pro forma
	(in thousands, except per unit amounts) (unaudited)	
Total revenues	$ 109,919	$ 60,774
Net income	$ 1,893	$ 6,321
Net income per unit:		
Common & Class B units – basic	$ 0.15	$ 0.77
Common & Class B units – diluted	$ 0.15	$ 0.77

3. Accounts Receivable and Allowance for Doubtful Accounts

We established an approximate $1.0 million provision for a loss on the entire amount due from a customer which filed for protection under Chapter 11 of the Bankruptcy Code in May 2007. The account receivable was due from oil sales through December 2006 at which time we ceased selling oil to the customer. As the amount of any potential recovery is uncertain, we elected to reserve the entire balance and it is reflected as bad debt expense on our consolidated statement of operations for the year ended December 31, 2007. We began selling our oil production to a new customer beginning in March 2007.

4. Credit Facilities and Long-Term Debt

Our credit facilities and long-term debt consisted of the following at December 31,:

Description	Interest Rate	Maturity Date	2008	2007
Senior secured reserve-based credit facility	Variable	March 31, 2011	$ 135,000,000	$ 37,400,000
Total			$ 135,000,000	$ 37,400,000

Senior Secured Reserve-Based Credit Facility

In January 2007, the Company entered into a four-year revolving reserve-based credit facility ("reserve-based credit facility") with Citibank, N.A. and BNP Paribas. All of our Predecessor's outstanding debt was repaid with borrowings under this reserve-based credit facility, including an early prepayment penalty of $2.5 million. The available credit line ("borrowing base") is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value (as determined by independent petroleum engineers) of estimated future net cash flows from certain proved natural gas and oil reserves of the Company. The initial borrowing base was set at $115.5 million and is secured by a first lien security interest in all of the Company's natural gas and oil properties. 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 the 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 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. 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, Compass Bank. As a result, indebtedness under the reserve-based credit facility totaled $135.0 million at December 31, 2008. In February 2009 our reserve-based credit facility was amended. See Note 12. *Subsequent Events* for further discussion.

Interest rates under the reserve-based credit facility are based on Euro-Dollars (LIBOR) or ABR (Prime) indications, plus a margin. Pursuant to the October 2008 reserve-based credit facility amendment our borrowing base utilization grid is 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%

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 certain distributions. Additionally, our reserve-based credit facility stipulates that a change of control is not permitted, which includes (1) an acquisition of ownership, directly or indirectly, beneficially or of record, by any person or group (within the meaning of the Securities Exchange Act of 1934 and the rules of the SEC) of equity interests representing more than 25% of the aggregate ordinary voting power represented by our issued and outstanding equity interests other than by Majeed S. Nami or his affiliates, or (2) the replacement of a majority of our directors by persons not approved by our board of directors. At December 31, 2008, we were in compliance with our debt covenants.

Our reserve-based credit facility required us to enter into a commodity price hedge position establishing certain minimum fixed prices for anticipated future production equal to approximately 84% of the projected production from proved developed producing reserves from the second half of 2007 through 2011. Also, our reserve-based credit facility 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 5. *Price Risk Management Activities* for further discussion.

5. 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, the Company receives 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 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 in the period that the related production is delivered. 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 in the Consolidated Statements of Operations.

On January 3, 2007, our Predecessor's natural gas price swaps were terminated, which resulted in the Company incurring swap termination fees of $2.8 million and an additional loss on derivative contracts of approximately $0.8 million included in our consolidated statement of operations for the year ended December 31, 2007. New natural gas derivative contracts were put in place in conjunction with entering into the reserve-based credit facility as described in Note 4. *Credit Facility and Long-Term Debt.* The Company paid $6.5 million for the put option contracts and payments for the put option contracts and the swap termination fee were funded with borrowings under the reserve-based credit facility. At our election, also in January 2007, we entered into a NYMEX natural gas collar contract. In May 2007, we reset our 2007, 2008 and 2009 natural gas swaps at higher prices and incurred a $7.3 million deferred swap payment obligation with the derivative counterparty which accrued interest daily at 7.36% and was payable at the earlier of five days after the closing of an equity issuance or November 1, 2007. The deferred swap obligation was paid in October 2007 using proceeds from our IPO.

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 the Company 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 existing producing wells for the period beginning July 2008 through December 2011.

In November 2008, in connection with preparing our quarterly report for third quarter 2008 and discussion with BDO Seidman, LLP, the Company's new independent registered public accounting firm, management of the Company and the Audit Committee of its Board of Directors concluded that the contemporaneous formal documentation it had prepared to support its initial hedge designations and subsequent assessments for ineffectiveness in connection with the Company's natural gas and oil hedging program in 2008 did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with SFAS 133. The primary reasons for this determination were that the formal hedge documentation lacked specificity of the hedged cash flow and the quantitative subsequent assessments for ineffectiveness were insufficient. Therefore, the cash flow designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. In addition, the natural gas derivative swap contracts entered into in 2007 were de-designated as cash flow hedges in the first quarter of 2008 due to an overhedged position in natural gas which made them ineffective. As a result, the Company now recognizes changes in its derivatives' fair values in current earnings under gains (losses) on other commodity derivative contracts. In addition, the net derivative loss at December 31, 2007 related to the de-designated natural gas derivate swap contracts entered into in 2007 is reported in accumulated other comprehensive income until the month in which the transactions settle, at which time it is recognized as gains (losses) on commodity cash flow hedges.

At December 31, 2008, the Company had 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**
2009	3,629,946	$ 9.42	181,500	$ 87.23
2010	3,236,040	$ 9.10	164,250	$ 85.65
2011	2,962,312	$ 7.82	151,250	$ 85.50
2012	—	$ —	144,000	$ 80.00

Put Option Contracts

Contract Period	Volume in MMBtu	Purchased NYMEX Price Floor
2009	840,143	$ 7.50

Collars

	Gas			Oil		
	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
Production Period:						
2009	1,000,000	$ 7.50	$ 9.00	36,500	$ 100.00	$ 127.00
2010	730,000	$ 8.00	$ 9.30	—	$ —	$ —

In February 2009, we liquidated our 2012 oil swap and entered into new natural gas derivative contracts. See Note 12. *Subsequent Events* for further discussion.

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, the company reduced its borrowing cost 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, the company 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, the Company recorded changes in the fair value of its 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.

At December 31, 2008, the Company had open interest rate derivative contracts as follows:

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

6. Fair Value Measurements

As discussed in Note 1. Summary of Significant Accounting Policies (b), we prospectively adopted SFAS 157 for financial assets and financial liabilities. 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 natural gas and oil 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 the Company's 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.

Certain provisions of SFAS 157 have been deferred by the FASB. Accordingly, the Company has not applied the provisions of SFAS 157 to those non-financial assets and liabilities which are not measured at fair value on a non-recurring basis. This includes asset retirement obligations, and any assets other than natural gas and oil properties, for which an impairment write down is recorded during the period. There have been no such asset impairments in the current period.

The Company has 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 the company's own credit standing (when valuing liabilities) and the buyer's risk premium. In adopting SFAS 157, the Company determined that the impact of these additional assumptions on fair value measurements did not have a material effect on financial position or results of operations. The Company is still assessing the potential impact of implementation in 2009 of those portions of the guidance for which the effective date has been deferred by the FASB.

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 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 external corroboration 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. The Company has 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:

	December 31, 2008			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
Assets:				
Commodity derivative contracts	$ —	$ 37,932,369	$ —	$ 37,932,369
Total derivative instruments	$ —	$ 37,932,369	$ —	$ 37,932,369
Liabilities:				
Interest rate derivative contracts	$ —	$ (2,799,911)	$ —	$ (2,799,911)
Total derivative instruments	$ —	$ (2,799,911)	$ —	$ (2,799,911)

7. Asset Retirement Obligations

The asset retirement obligations as of December 31 reported on our consolidated balance sheets and the changes in the asset retirement obligations for the year ended December 31, were as follows:

	2008	2007
Asset retirement obligation at January 1,	$ 189,711	$ —
Liabilities added during the current period	1,882,397	177,153
Accretion expense	61,683	12,558
Asset retirement obligation at December 31,	$ 2,133,791	$ 189,711

Accretion expense for the years ended December 31, 2008, 2007 and 2006 was $61,683, $12,558 and $18,307, respectively.

8. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. We reimburse Vinland $60 per well per month (in addition to normal third party operating costs) for operating our current natural gas and oil properties in Appalachia under a Management Services Agreement ("MSA") which costs are reflected in our lease operating expenses. Also, Vinland receives a $0.25 per mcf transportation fee for producing wells as of January 5, 2007 and $0.55 per mcf transportation fee on any new wells drilled after January 5, 2007 within the area of mutual interest or "AMI." This transportation fee only encompasses transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets apply. These transportation fees are outlined under a Gathering and Compression Agreement ("GCA") with Vinland and are reflected in our lease operating expenses. For the years ended December 31, 2008 and 2007, costs incurred under the MSA were $0.6 million and $0.5 million, respectively and costs incurred under the GCA were $1.0 million and $1.2 million, respectively. In addition, for the year ended December 31, 2007, Vinland reimbursed us for certain gas sales contracts that were fixed at prices below market in the amount of $1.0 million which is reflected in natural gas and oil sales. A payable of $2.6 million and $3.8 million, respectively, is reflected on our December 31, 2008 and December 31, 2007 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. In September 2008, the Company acquired certain natural gas and oil properties in Appalachia from Vinland for a total purchase price of $4.0 million. The consideration included $3.1 million in cash and $0.9 million reduction in amounts previously due to Vanguard.

9. Commitments and Contingencies

The Company is a defendant in a legal proceeding arising in the normal course of our business. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management does not believe that it is probable that the outcome of any action will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flow.

Nami Resources Company, LLC, a subsidiary of our Predecessor that was retained by our founding unitholder in connection with the Restructuring, has been involved in an ongoing dispute with Asher Land and Mineral Company, Ltd., or Asher, pursuant to which Asher claims, among other things, that Nami Resources Company, LLC did not correctly calculate the royalties paid to it and that it failed to abide by certain terms of the leases relating to the coordination of oil and gas development with coal development activities.

On September 8, 2006, Asher filed a complaint in Kentucky state court initiating an action styled *Asher Land and Mineral, Ltd. v. Nami Resources Company, LLC,* Bell Circuit Court, Civil Action No. 06-CI-00417. In that action, Asher sought monetary damages and court-ordered rescission of the leases. Before a responsive pleading was filed, Asher voluntarily withdrew its complaint and dismissed the case. On December 15, 2006, Asher filed a new action styled *Asher Land and Mineral, Ltd. v. Nami Resources Company, LLC*, Bell Circuit Court, Civil Action No. 06-CI-00566. In that action, Asher has made the same allegations as in the prior suit and added a claim for an undetermined amount of punitive damages. The parties have exchanged limited initial discovery requests.

On August 29, 2007, Asher filed a motion to add additional defendants to the action cited above, including Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC and Trust Energy Company, LLC. The Company has filed several motions to be dismissed from this action but to date is still a named defendant in this case. Since that time, no discovery has been sought from the Company by Asher. We have retained separate counsel to represent us in this case as it progresses and intend to continue to vigorously defend the action.

We received a contract right to receive approximately 99% of the net proceeds from the sale of production from certain producing oil and gas wells located within the Asher lease, which accounted for approximately 2.6% of our estimated proved reserves as of December 31, 2008. We did not receive an assignment of any working interest in the Asher lease. The Asher lease and the litigation related thereto were retained by Nami Resources Company, LLC. If the Asher lease is terminated or if Nami Resources Company, LLC's rights to production under wells of which we have contract rights to receive proceeds are adversely affected, we could lose our contract rights to receive such proceeds or it could be adversely affected.

Nami Resources Company, LLC and Vinland have agreed to indemnify us for all liabilities, judgments and damages that may arise in connection with the litigation referenced above as well as providing for the defense of any such claims. The indemnities agreed to by Nami Resources Company, LLC and Vinland will remain in place until the resolution of the Asher litigation.

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

In April 2007, the sole member of VNG contributed all of the issued and outstanding common units in VNG to VNR for six million common units representing all of the issued and outstanding common units of VNR at such time. VNR then completed a private equity offering pursuant to which it sold 2.29 million common units to certain private investors for $41.2 million. The proceeds of this private equity offering were used to make a distribution to Majeed S. Nami, VNR's largest unitholder. Mr. Nami used a portion of these funds to capitalize Vinland and Vinland paid us $3.9 million to reduce outstanding accounts receivable from Vinland. In October 2007, we successfully completed our IPO of 5.25 million common units.

Basic earnings per unit is computed in accordance with SFAS No. 128, *"Earnings Per Share"* ("SFAS 128") by dividing net earnings 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. The Company uses the treasury stock method to determine the dilutive effect. At December 31, 2008, the Company had two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on NYSE Arca under the symbol VNR and (ii) Class B units, issued to officers and an employee as discussed in Note 11.*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 and phantom units granted to officers under our long-term incentive plan had no dilutive effect; 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 years ended December 31, 2008 and 2007 for 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 units and the Class B units on an equal basis. No calculation was made for the Vanguard Predecessor period.

11. Unit-Based Compensation

In April 2007, the sole member 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, 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 which will vest 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, have a term of five years and had a fair value of $0.1 million on the date of grant.

Furthermore, on March 27, 2008, phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2008 and the amount to be paid was equal to the appreciation in value of the units, if any, from the date of the grant until the determination date (December 31, 2008), plus cash distributions paid on the units, less an 8% hurdle rate. As of December 31, 2008, there was no appreciation in the value of these units; therefore, no liability or expense was recognized. 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 are subject to accounting for these grants under SFAS 123(R), Share-Based Payment.

The fair value of restricted units issued is determined based on the fair market value of VNR 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 December 31, 2008 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2007	425,000	$ 18.14
Granted	15,000	16.79
Non-vested units at December 31, 2008	440,000	$ 18.10

At December 31, 2008, there was approximately $2.3 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 0.8 years. Our consolidated statements of operations reflects non-cash compensation of $3.6 million and $2.1 million in the selling, general and administrative expenses line item for the years ended December 31, 2008 and 2007, respectively.

12. Subsequent Events

Our reserve-based credit facility was amended in February 2009 to amend covenants to allow the Company to repurchase up to $5.0 million of our own units.

In February 2009, we liquidated our 2012 oil swap and entered into new 2010 and 2011 natural gas swap and collar transactions. Specifically, an $8.04 and $7.85 fixed price NYMEX natural gas swap for January through September 2010 and April through September 2011, 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 set at prices above the current market by using the proceeds of the liquidation of the 2012 oil swap.

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(in thousands, except per unit amounts)				
2008					
Natural gas and oil sales	$ 14,002	$ 20,852	$ 20,839	$ 13,157	$ 68,850
Gain (loss) on commodity cash flow hedges	416	155	45	(347)	269
Gain (loss) on other commodity derivative contracts	(21,772)	(58,045)	63,364	48,930	32,477
Total revenues	(7,354)	(37,038)	84,248	61,740	101,596
Impairment of natural gas and oil properties	—	—	—	58,887	58,887
Other costs and expenses (1)	7,452	8,696	10,495	11,059	37,702
Total costs and expenses	7,452	8,696	10,495	69,946	96,589
Net income (loss)	$ (15,932)	$ (47,020)	$ 71,809	$ (12,608)	$ (3,751)
Net income (loss) per unit:					
Common & Class B units – basic	$ (1.42)	$ (4.19)	$ 5.90	$ (1.00)	$ (0.32)
Common & Class B units – diluted	$ (1.42)	$ (4.19)	$ 5.90	$ (1.00)	$ (0.32)
2007					
Natural gas and oil sales	$ 8,962	$ 10,107	$ 7,641	$ 7,831	$ 34,541
Gain (loss) on commodity cash flow hedges	(748)	(918)	940	24	(702)
Total revenues	8,214	9,189	8,581	7,855	33,839
Total costs and expenses (1)	5,128	4,767	5,026	5,694	20,615
Net income (loss)	$ (1,626)	$ 2,240	$ 1,051	$ 984	$ 2,649
Net income (loss) per unit:					
Common & Class B units – basic	$ (0.29)	$ 0.38	$ 0.18	$ 0.10	$ 0.39
Common & Class B units – diluted	$ (0.2 9)	$ 0.38	$ 0.18	$ 0.10	$ 0.39

(1) Includes lease operating expenses, depreciation, depletion, amortization and accretion, selling, general and administration expenses, bad debt expense and production and other taxes.

Supplemental Natural Gas and Oil Information (Unaudited)

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.

Capitalized costs related to natural gas and oil producing activities and related accumulated depletion, amortization and accretion were as follows at December 31:

	2008	2007
Aggregate capitalized costs relating to natural gas and oil producing activities	$ 284,446,984	$ 135,435,240
Aggregate accumulated depletion, amortization and accretion	(102,178,304)	(28,451,891)
Net capitalized costs	$182,268,680	$106,983,349
SFAS 143 asset retirement obligations	$ 2,133,791	$ 189,711

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows for the years ended December 31:

	Vanguard		Vanguard Predecessor
	2008	2007	2006
Property acquisition costs	$128,323,699	$ 3,670,561	$ —
Development costs	19,097,637	12,859,838	37,467,066
Total cost incurred	$ 147,421,336	$16,530,399	$37,467,066

The table above includes capitalized internal costs incurred in connection with the development of natural gas and oil reserves of $3,880,000 in 2006. No internal costs were capitalized in 2008 or 2007. Additionally, capitalized interest of $58,960, $75,672 and $117,097 for the years ended December 31, 2008, 2007 and 2006, respectively, are included in the table above.

Net quantities of proved developed and undeveloped reserves of natural gas and oil and changes in these reserves at December 31, 2008, 2007 and 2006 are presented below. Information in these tables is based on reserve reports prepared by our independent petroleum engineers, Netherland, Sewell & Associates, Inc. for 2008, 2007 and 2006.

	Gas (in Mcf)	Oil (in Bbls)
Net proved reserves		
January 1, 2006	107,690,281	463,693
Revisions of previous estimates	(17,529,333)	(106,630)
Extensions, discoveries and other	8,205,425	18,623
Production	(4,181,708)	(32,718)
December 31, 2006	94,184,665	342,968
Revisions of previous estimates	(31,943,375)	798
Extensions, discoveries and other	4,544,443	16,725
Purchases of reserves in place	2,387,113	6,165
Production	(4,044,380)	(30,629)
December 31, 2007	65,128,466	336,027
Revisions of previous estimates	(5,475,099)	73,480
Extensions, discoveries and other	5,856,100	25,017
Purchases of reserves in place	20,089,537	4,374,410
Production	(4,361,907)	(261,575)
December 31, 2008	81,237,097	4,547,359
Proved developed reserves		
December 31, 2006	48,166,327	249,329
December 31, 2007	48,897,929	233,507
December 31, 2008	58,315,899	3,766,394

Revisions of previous estimates of reserves are a result of changes in natural gas and oil prices, production costs, well performance and the reservoir engineer's methodology. Changes in natural gas prices had a significant impact on proved reserves in 2006. From December 31, 2005 to December 31, 2006, the revisions of previous estimates for natural gas reduced proved reserves by 17.5 Bcf largely due to natural gas prices decreasing from $9.89 per MMbtu to $5.63 per MMbtu at the respective year ends. From December 31, 2006 to December 31, 2007, the revisions of previous estimates for natural gas reduced proved reserves by 31.9 Bcf primarily due to the value of the 60% interest in proved undeveloped properties which was conveyed to Vinland in the Restructuring.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2008.

Results of operations from producing activities were as follows for the years ended December 31:

	Vanguard		Vanguard Predecessor
	2008	2007	2006
Production revenues (1)	$ 62,542,789	$ 33,838,191	$ 35,976,571
Production costs (2)	(15,799,836)	(7,119,834)	(6,670,542)
Depreciation, depletion and amortization	(14,812,305)	(8,960,524)	(8,511,390)
Impairment of natural gas and oil properties	(58,886,660)	—	—
Results of operations from producing activities	$(26,956,012)	$ 17,757,833	$ 20,794,639

(1) Production revenues include gains and losses on commodity cash flow hedges in 2008 and 2007 and realized losses on other commodity derivative contracts in 2008 and 2006.

(2) Production cost includes lease operating expenses and production related taxes, including ad valorem and severance taxes.

The standardized measure of discounted future net cash flows relating to our proved natural gas and oil reserves at December 31 is as follows (in thousands):

	Vanguard		Vanguard Predecessor
	2008	2007	2006
Future cash inflows	$ 739,560	$ 587,639	$ 663,604
Future production costs	(258,948)	(173,485)	(192,520)
Future development costs	(50,268)	(36,842)	(66,906)
Future net cash flows	430,344	377,312	404,178
10% annual discount for estimated timing of cash flows	(240,271)	(226,315)	(255,357)
Standardized measure of discounted future net cash flows	$ 190,073	$ 150,997	$ 148,821

For the December 31, 2008 calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $5.71 per MMBtu for natural gas, adjusted by field for energy content, and $41.00 per barrel of oil, adjusted for quality, transportation fees and a regional price differential. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

The following are the principal sources of change in our standardized measure of discounted future net cash flows (in thousands):

	Year Ended December 31, (1)		
	Vanguard		Vanguard Predecessor
	2008	2007	2006
Sales and transfers, net of production costs	$ (53,050)	$ (26,718)	$ (29,306)
Net changes in prices and production costs	(20,385)	52,625	(231,630)
Extensions discoveries and improved recovery, less related costs	13,036	10,791	21,110
Changes in estimated future development costs	(12,056)	18,045	(24,336)
Previously estimated development costs incurred during the period	19,956	16,531	37,467
Revision of previous quantity estimates	(10,149)	(75,071)	(31,726)
Accretion of discount	15,100	14,882	40,043
Purchases of reserves in place	82,454	4,249	—
Change in production rates, timing and other	4,170	(13,158)	(33,230)
Net change	$ 39,076	$ 2,176	$ (251,608)

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

As previously reported in our Current Report on Form 8-K dated September 2, 2008, on August 27, 2008, UHY LLP ("UHY") advised us that, in light of the Company's employment of a member of the UHY audit engagement team, effective as of September 8, 2008, UHY would no longer be able to serve as the Company's independent registered public accounting firm because it believed it would no longer satisfy the independence requirements necessary to certify the financial statements of the Company. As a result, UHY resigned as the Company's independent registered public accounting firm, effective as of August 27, 2008. UHY expressed an unqualified opinion on the consolidated financial statements of the Company for the year ended December 31, 2007 and the consolidated financial statements of Vanguard Natural Gas, LLC (formerly Nami Holding Company, LLC) for the year ended December 31, 2006. During the two most recent fiscal years and interim period preceding UHY's resignation, there were no (a) disagreements with UHY or (b) any reportable events as defined under Item 304(a)(1)(v) of Regulation S-K. Also, as previously reported in our Current Report on Form 8-K dated October 14, 2008, our audit committee approved the engagement terms of BDO Seidman, LLP ("BDO") and authorized BDO to serve as our independent registered public accountants for the fiscal year ending December 31, 2008.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management has established and maintains a system of disclosure controls and procedures to provide reasonable assurances that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

As part of the preparation of our financial statements for the quarters ended March 31, 2008 and June 30, 2008, we undertook a review of our accounting for natural gas and oil and interest rate derivatives. We use derivative instruments as a means of reducing financial exposure to fluctuating natural gas and oil prices and interest rates. We included changes from period to period in the fair value of derivatives classified as cash flow hedges as increases or decreases to Accumulated Other Comprehensive Income ("AOCI") as allowed by Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" ("SFAS 133"). This hedge accounting treatment is allowed for certain derivatives, including the types of derivatives used by us to reduce exposure to changes in natural gas and oil prices associated with the sale of natural gas and oil production and fluctuations in interest rates. In order to qualify for hedge accounting treatment, specific standards and documentation requirements must be met. We believed that we met those requirements and that our hedge accounting treatment was permitted under SFAS 133. However, in connection with preparing our quarterly report for third quarter of 2008 and discussion with BDO, we determined that our commodity derivative instruments did not qualify for hedge accounting treatment under SFAS 133 in 2008. Specifically, we determined that the formal hedge documentation lacked specificity of the hedged cash flow and the quantitative subsequent assessments for ineffectiveness were insufficient. Therefore, the cash flow designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment for commodity derivative contracts entered into during periods subsequent to December 31, 2007; and, that accounting for commodity derivative instruments entered into during periods subsequent to December 31, 2007 as cash flow hedges was, therefore, inappropriate. In addition, the natural gas derivative swap contracts entered into in 2007 were de-designated as cash flow hedges in the first quarter of 2008 due to an overhedged position in natural gas which made them ineffective. Accordingly, we restated the consolidated financial statements for the three months ended March 31, 2008 and June 30, 2008 as reflected in our Form 10-Q's to reflect the appropriate changes. Management has concluded, based on the circumstances involving the restatement of the aforementioned financial statements that from March 31, 2008 through September 30, 2008, a material weakness in internal control over financial reporting existed with respect to the design of the Company's controls over the proper recording and disclosure of derivative instruments in accordance with SFAS 133.

We carried out an evaluation in accordance with Exchange Act Rules 13a-15 under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, due to the aforementioned material weakness, our disclosure controls and procedures were not effective through September 30, 2008. The Company evaluated the necessary changes in control procedures required to remediate this material weakness and elected to no longer account for future derivative instruments as cash flow hedges under SFAS 133. As such, the Company now recognizes changes in its derivatives' fair value in current earnings under gains (losses) on other commodity and interest rate derivative contracts. Accordingly, the Company's internal controls over financial reporting were effective at the reasonable assurance level at December 31, 2008. See BDO Seidman, LLP's report on our internal control over financial reporting as of December 31, 2008 set forth below in Part II, Item 9A (d) under Attestation Report.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by SEC rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed 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. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2008. In making this assessment, we used the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2008. The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by BDO Seidman, LLP, an independent registered public accounting firm, as stated in their report included herein.

(c) Changes in Internal Control over Financial Reporting

In response to the material weakness noted in Item 9A (a) above during the fourth quarter 2008, the Company elected to no longer account for future derivative instruments as cash flow hedges under SFAS 133 and now recognizes changes in its derivatives' fair value in current earnings under gains (losses) on other commodity and interest rate derivative contracts. There were no other changes in our internal control over financial reporting during this quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(d) Attestation Report

Report of Independent Registered Public Accounting Firm
on Internal Control over Financial Reporting

Board of Directors and Shareholders
Vanguard Natural Resources, LLC
Houston, Texas

We have audited Vanguard Natural Resources, LLC's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Vanguard Natural Resources, LLC's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Item 9A, Management's Report on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Vanguard Natural Resources, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Vanguard Natural Resources LLC as of December 31, 2008 and the related consolidated statements of operations, comprehensive income (loss), members' equity, and cash flows for the year ended December 31, 2008 and our report dated March 10, 2009 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Houston, Texas
March 10, 2009

ITEM 9B.OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2008.

ITEM 11. EXECUTIVE COMPENSATION

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2008.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Item 12 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2008.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2008.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2008.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Financial statements

The following consolidated financial statements are included in Part II, Item 8 of this report:

(b) Exhibits

The following exhibits are incorporated by reference into the filing indicated or are filed herewith.

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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)
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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	Filed herewith

	the Sarbanes-Oxley Act of 2002		
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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 on the 11th day of March, 2009.

VANGUARD NATURAL RESOURCES, LLC

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

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Scott W. Smith and Richard A. Robert, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this Annual Report on Form 10-K, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

March 11, 2009	/s/ Scott W. Smith Scott W. Smith President, Chief Executive Officer and Director (Principal Executive Officer)
March 11, 2009	/s/ Richard A. Robert Richard A. Robert Executive Vice President and Chief Financial Officer (Principal Financial Officer)
March 11, 2009	/s/ W. Richard Anderson W. Richard Anderson Director
March 11, 2009	/s/ Bruce W. McCullough Bruce W. McCullough Director
March 11, 2009	/s/ John R. McGoldrick John R. McGoldrick Director
March 11, 2009	/s/ Loren Singletary Loren Singletary Director
March 11, 2009	/s/ Lasse Wagene Lasse Wagene Director

Vanguard Natural Resources, LLC
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EXHIBIT 10.34

FIRST AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT

THIS FIRST AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT is made as of May15, 2008 (the ***"First Amendment to Restated Credit Agreement,"*** or this ***"Amendment"***), among **VANGUARD NATURAL GAS, LLC**, a Kentucky limited liability company (***"Borrower"***), the lenders listed on the signature pages hereto as Lenders (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 (the ***"Restated Credit Agreement"***).

B. The parties desire to amend the Restated 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 Restated 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 Restated 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 May 15, 2008.

"Modification Papers" means this Amendment, the First Amendment to NRC Guaranty Agreement, the Guarantor Confirmation Letters, 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. **First Amendment to Restated Credit Agreement**. This First Amendment to Restated Credit Agreement shall be in full force and effect.

B. **First Amendment to NRC Guaranty Agreement**. Nami Resources Company L.L.C. shall have executed and delivered to Administrative Agent an amendment to the Unconditional Guaranty of Nami Resources Company L.L.C. (the ***"First Amendment to NRC Guaranty Agreement"***), which shall be satisfactory in form and substance to Administrative Agent.

C. **Guarantor Confirmation Letters**. Each of Ariana Energy, LLC and Trust Energy Company, LLC shall have executed a letter in favor of Administrative Agent (each a ***"Guarantor Confirmation Letter"***) confirming that its Guaranty remains in full force and effect.

D. **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.

E. **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. **Amendments to Restated Credit Agreement**. On the Effective Date, the Restated Credit Agreement shall be deemed to be amended as follows:

(a) The definition of "Swap Agreement" shall be amended to read in its entirety as follows:

"'**Swap Agreement**' means any agreement with respect to any swap, forward, future or derivative transaction or option (whereby the aggregate position for options creates an obligation for Borrower) or similar agreement, whether exchange traded, "over-the-counter" or otherwise, involving, or settled by reference to, one or more rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions; provided that no phantom stock or similar plan providing for payments only on account of services provided by current or former directors, managers, officers, employees or consultants of Borrower or the Subsidiaries shall be a Swap Agreement."

(b) Section 2.07(a) of the Restated Credit Agreement shall be deemed to be amended as follows:

"The term '**Borrowing Base**' means, as of the date of the determination thereof, the designated loan value as calculated by the Lenders in their sole discretion assigned to the discounted present value of future net income accruing to the Mortgaged Property, based upon the Lenders' in-house evaluation of the Mortgaged Property. The Lenders' determination of the Borrowing Base will be made in accordance with then-current practices, economic and pricing parameters, methodology, assumptions, and customary procedures and standards established by each Lender from time to time for its petroleum industry customers. Borrower acknowledges that the determination of the Borrowing Base contains an equity cushion (market value in excess of loan amount) which Borrower acknowledges to be essential for the adequate protection of the Lenders. For the period from and including the date on which the conditions in Section 6.03 were satisfied to but excluding the next Redetermination Date, the amount of the Borrowing Base shall be $150,000,000. Borrower further acknowledges and agrees that in calculating the Borrowing Base, the combined value of the Asher PD Properties and the Asher PUD Properties shall not exceed the maximum liability of NRC with respect to the principal amount of the Notes guaranteed by NRC as provided in the Guaranty Agreement of NRC as amended from time to time. Notwithstanding the foregoing, the Borrowing Base may be subject to further adjustments from time to time pursuant to Section 8.13(c)."

4. **Temporary Waiver – 95% Ceiling for Crude Oil Swaps**. Pursuant to Section 9.18 of the Restated Credit Agreement, Borrower is prohibited from hedging more than 95% of the reasonably anticipated projected production from proved, developed, producing Oil and Gas Properties for natural gas and crude oil. Borrower proposes to acquire certain non-operating working interests in proved, developed, producing Oil and Gas Properties producing natural gas and crude oil from Greenbriar Energy LP IV (the ***"Greenbriar Acquisition"***). Concurrently with its execution of the purchase and sale agreement for the Greenbriar Acquisition, Borrower proposes to enter into Swap Agreements for forecasted production of crude oil which will exceed the 95% ceiling imposed by Section 9.18 of the Restated Credit Agreement (the ***"Swap Violation"***). If the Greenbriar Acquisition is consummated, the additional production from the newly acquired Oil and Gas Properties will bring Borrower back into compliance with Section 9.18 of the Restated Credit Agreement. If the Greenbriar Acquisition fails to close, Borrower will unwind the Swap Agreements in order to get back into compliance with the 95% ceiling for crude oil production set forth in Section 9.18 of the Restated Credit Agreement. Absent a waiver, the Swap Violation will constitute an Event of Default under Section 10.01(d) of the Restated Credit Agreement. The Administrative Agent and the Lenders hereby waive the exercise of their rights and remedies for the Event of Default resulting from the Swap Violation until 5:00 p.m. Friday, July 11, 2008, subject to the following:

(i) During the period that the Swap Violation exists, Borrower will maintain unencumbered liquid assets having an aggregate value of at least $10,000,000 (the phrase "unencumbered liquid assets" shall have the same meaning as set forth in Section 9.01(d) of the Restated Credit Agreement);

(ii) During the period that the Swap Violation exists, Borrower will not enter into Swap Agreements for forecasted production of crude oil which will exceed more than 107% of the reasonably anticipated projected production from proved, developed, producing Oil and Gas Properties for crude oil; and

(iii) If the Swap Violation continues to exist after 5:00 p.m. on Friday, July 11, 2008, an Event of Default shall be deemed to exist under Section 10.01(d) of the Restated Credit Agreement.

5. **Limitations as to Temporary Waiver of Swap Violation**. The waivers granted herein and the future failure of the Administrative Agent and/or the Lenders to exercise available rights and remedies is not intended (a) to operate as a waiver of rights and remedies due to defaults other than the Event of Default resulting from the Swap Violation, or (b) to indicate any agreement on the part of the Administrative Agent and the Lenders to waive their rights and remedies in the future. The waivers and consents set forth herein are limited precisely as written and shall not be deemed (a) to be a waiver or waivers of or a consent or consents to the modification of or deviation from any other term or condition of the Credit Agreement or the Loan Documents, or (b) to prejudice any right or rights which the Administrative Agent and/or the Lenders may now have or may have in the future under or in connection with the Credit Agreement or any of the other Loan Documents.

6. **Release**. To induce the Administrative Agent and the Lenders to agree to the temporary waiver of the Swap Violation, Borrower warrant and represent that as of the Effective Date, there are no claims or offsets or defenses or counterclaims to the obligations of Borrower under the Loan Documents, and in accordance therewith, Borrower:

(a) Waives any and all such claims, offsets, defenses or counterclaims, whether known or unknown, arising under the Loan Documents prior to the Effective Date; and

(b) Releases and discharges the Administrative Agent and the Lenders and their officers, directors, employees, agents, shareholders, affiliates and attorneys (the "***Released Parties***") from any and all obligations, indebtedness, liabilities, claims, rights, causes of action or other demands whatsoever, whether known or unknown, suspected or unsuspected, in law or equity, which Borrower ever had, now have or claim to have or may have against any Released Parties arising prior to the Effective Date and from or in connection with the Loan Documents or the transactions contemplated thereby, except those resulting from the gross negligence or willful misconduct of the Released Parties.

7. **Certain Representations**. Borrower represents and warrants that, as of the Effective Date: (a) Borrower and each Guarantor has full power and authority to execute the Modification Papers to which it is a party and the Modification Papers executed by Borrower and each Guarantor constitute the legal, valid and binding obligation of Borrower and each such Guarantor 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 or each such Guarantor thereof. In addition, Borrower represents that all representations and warranties contained in the Restated 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).

8. **No Further Amendments.** Except as previously amended in writing or as amended hereby, the Restated Credit Agreement shall remain unchanged and all provisions shall remain fully effective among the parties.

9. **Limitation on Agreements**. 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 Restated 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 Restated 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.

10. **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.

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

12. **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.

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/ Betsy Jocher
Name: Betsy Jocher
Title: Director

By: /s/ Robert Long
Name: Robert Long
Title: Vice President

LENDERS: **WACHOVIA BANK, NATIONAL ASSOCIATION**

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

LENDERS: **THE BANK OF NOVA SCOTIA**

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

EXHIBIT 10.35

THIRD AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT

THIS THIRD AMENDMENT TO FIRST AMENDED AND RESTATED CREDIT AGREEMENT is made as of February 18, 2009 (the ***"Third 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 (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 February 18, 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. **Third Amendment to Restated Credit Agreement**. This Third Amendment to Restated Credit Agreement shall be in full force and effect.

B. **Guarantor Confirmation Letters**. Each of Ariana Energy, LLC and Trust Energy Company, LLC shall have executed a letter in favor of Administrative Agent (each a ***"Guarantor Confirmation Letter"***) confirming that its Guaranty remains in full force and effect.

C. **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.

D. **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. **Amendments to Original Credit Agreement**. On the Effective Date, the Original Credit Agreement shall be deemed to be amended as follows:

(a) The Equity Interests of the Borrower are owned 100% by Vanguard Natural Resources, LLC. The parties have agreed to include the financial results of Vanguard Natural Resources, LLC with the consolidated financial results of the Borrower and its Subsidiaries for purposes of determining compliance with the financial covenants set forth in Sections 9.01(a), (b) and (c) of the Original Credit Agreement. Accordingly, the definitions of "Consolidated Leverage Ratio," "EBITDA," "Interest Expense" and "Total Debt" set forth in Section 1.02 of the Original Credit Agreement shall be amended to read in their entirety as follows:

"'**Consolidated Leverage Ratio**' means, as of any date of determination, for the Borrower, the Consolidated Subsidiaries and Vanguard Natural Resources, LLC on a consolidated basis, the ratio of (a) Total Debt as of such date to (b) EBITDA for each four consecutive fiscal quarter period ending on and after December 31, 2007. For purposes of calculating the Consolidated Leverage Ratio at any date, EBITDA shall be calculated on a pro forma basis (as certified by the Borrower to the Administrative Agent and as approved by the Administrative Agent) assuming that all acquisitions made, and all dispositions completed, during the four consecutive fiscal quarters then most recently ended have been made on the first day of such period (but without any adjustment for projected cost savings or other synergies).

'**EBITDA**' means, for any twelve-month period (except as otherwise expressly provided) ending on the last day of any fiscal quarter, consolidated net income, excluding any non-cash revenue or expense associated with Swap Agreements resulting from FAS 133, **plus** without duplication and to the extent deducted from revenues in determining consolidated net income, the sum of (a) the aggregate amount of consolidated Interest Expense for such period, (b) the aggregate amount of income tax expense for such period, (c) all amounts attributable to depletion, depreciation and amortization for such period, and (d) all other non-cash charges, all determined on a consolidated basis with respect to Borrower, the Consolidated Subsidiaries and Vanguard Natural Resources, LLC in accordance with GAAP, using the results of the twelve-month period ending with that reporting period (except as otherwise herein provided).

'**Interest Expense**' means, for any period, the sum (determined without duplication) of the aggregate gross interest expense of the Borrower, the Consolidated Subsidiaries and Vanguard Natural Resources, LLC for such period, including to the extent included in interest expense under GAAP: (a) amortization of debt discount, (b) capitalized interest and (c) the portion of any payments or accruals under Capital Leases allocable to interest expense, minus (i) the portion of any payments or accruals under Synthetic Leases allocable to interest expense, and (ii) and any imputed interest pursuant to asset retirement obligations whether or not the same constitutes interest expense under GAAP.

'**Total Debt**' means, at any date, all Debt of the Borrower, the Consolidated Subsidiaries and Vanguard Natural Resources, LLC on a consolidated basis, excluding (i) non-cash obligations under FAS 133 and (ii) accounts payable and other accrued liabilities (for the deferred purchase price of Property or services) from time to time incurred in the ordinary course of business which are not greater than sixty (60) days past the date of invoice or delinquent or which are being contested in good faith by appropriate action and for which adequate reserves are maintained in accordance with GAAP."

(b) Section 9.01(a) of the Original Credit Agreement shall be amended to read in its entirety as follows:

"(a) Interest Coverage Ratio. The Borrower will not, as of the last day of any fiscal quarter beginning with the fiscal quarter ending December 31, 2007, permit its ratio of EBITDA, *less* the aggregate amount of cash used to purchase Equity Interests of Vanguard Natural Resources, LLC for the twelve month period ending on the last day of such fiscal quarter, to Interest Expense for such twelve month period, to be less than 2.5 to 1.0."

(c) Section 9.04(e) of the Original Credit Agreement shall be amended to read in its entirety as follows:

"(e) the Borrower may make Restricted Payments to its Equity Interest holders provided that (i) no Default has occurred and is continuing or would result from the making of such Restricted Payment, and (ii) after giving effect to such Restricted Payment, the Revolving Credit Exposure is less than 90% of the Borrowing Base as of such date, and (iii) in the case of a Restricted Payment which will be used by Vanguard Natural Resources, LLC to purchase treasury stock, the sum of the amounts of all such payments to date, plus the amount of such proposed Restricted Payment, does not exceed $5,000,000."

(d) Exhibit D to the Original Credit Agreement shall be amended by replacing it in its entirety with Exhibit D attached hereto.

4. **Guarantor Confirmation Letter – Nami Resources**. On or before April 30, 2009, Borrower shall have caused Nami Resources Company L.L.C. to deliver to Administrative Agent a Guarantor Confirmation Letter which shall be satisfactory in form and substance to Administrative Agent. A breach of this covenant shall constitute an Event of Default under the Original Credit Agreement with no further grace period being applicable.

5. **Certain Representations**. Borrower represents and warrants that, as of the Effective Date: (a) Vanguard Natural Resources, LLC owns 100% of the issued and outstanding Equity Interests of Borrower; (b) 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 (c) 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).

6. **No Further Amendments**. 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.

7. **Limitation on Agreements**. 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.

8. **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.

9. **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.

10. **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.

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/ Betsy Jocher
Name: Betsy Jocher
Title: Director

By: /s/ Edward Pak
Name: Edward Pak
Title: Vice President

LENDERS: **WACHOVIA BANK, NATIONAL ASSOCIATION**

By: /s/ Shawn Young
Name: Shawn Young
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

EXHIBIT D

FORM OF

COMPLIANCE CERTIFICATE

The undersigned hereby certifies that he/she is the _______________ of **VANGUARD NATURAL GAS, LLC**, a Kentucky limited liability company (the "**Borrower**"), and that as such he/she is authorized to execute this certificate on behalf of the Borrower. With reference to the First Amended and Restated Credit Agreement dated as of February 14, 2008 (together with all amendments, restatements, supplements or other modifications thereto being the "**Agreement**") among the Borrower, **CITIBANK, N.A.**, as Administrative Agent, and the other agents and lenders (the "**Lenders**") which are or become a party thereto, and such Lenders, the undersigned represents and warrants as follows (each capitalized term used herein having the same meaning given to it in the Agreement unless otherwise specified):

(a) The representations and warranties of the Borrower contained in Article VII of the Agreement and in the Loan Documents and otherwise made in writing by or on behalf of the Borrower pursuant to the Agreement and the Loan Documents were true and correct in all material respects when made, and are repeated at and as of the time of delivery hereof and are true and correct in all material respects at and as of the time of delivery hereof, except to the extent such representations and warranties are expressly limited to an earlier date or the Majority Lenders have expressly consented in writing to the contrary.

(b) The Borrower has performed and complied with all agreements and conditions contained in the Agreement and in the Loan Documents required to be performed or complied with by it prior to or at the time of delivery hereof [or specify default and describe].

(c) Since _________________, 200_, no change has occurred, either in any case or in the aggregate, in the condition, financial or otherwise, of the Borrower or any Subsidiary which could reasonably be expected to have a Material Adverse Effect [or specify event].

(d) There exists no Default or Event of Default [or specify Default and describe].

(e) The aggregate amount of cash used to date by Vanguard Natural Resources, LLC to repurchase treasury stock is $_________________.

(f) Attached hereto are the detailed computations necessary to determine whether the Borrower is in compliance with Section 9.01 and Section 8.14 as of the end of the [fiscal quarter][fiscal year] ending [ ].

EXECUTED AND DELIVERED this _________ day of __________, 20__.

VANGUARD NATURAL GAS, LLC

By: ________________________
Name: ________________________
Title: ________________________

For the Quarter/Year ended ___________________("***Statement Date***")

SCHEDULE 2
to the Compliance Certificate
($ in 000's)

I. Section 9.01(a) – Interest Coverage Ratio.
A. EBITDA

1.consolidated net income, less	$_______________
2.non-cash revenue or expense associated with Swap Agreements resulting from FAS 133, less	($_______________)
3.income or plus loss from discontinued operations and extraordinary items, plus	($_______________)
4.income taxes, plus	$_______________
5.interest expense, plus	$_______________
6.depreciation, plus	$_______________
7.depletion, plus	$_______________
8.amortization, plus	$_______________
9.non-cash and extraordinary items	$_______________
10.Total EBITDA	$_______________
11. less the aggregate amount of cash used to purchase Equity Interests of Vanguard Natural Resources, LLC during the twelve month period ending on the Statement Date	$_______________
B. Interest Expense	$_______________
C. Ratio (Line I.A.11 ÷ Line I.B)	_________ to 1.0

Minimum Required: 2.5 to 1.0

II. Section 9.01(b) – Consolidated Leverage Ratio.

A. Total Debt	
1.Debt, less	$________________
2.Non-cash obligations under FAS 133, less	($________________)
3.Accounts payable and other accrued liabilities not greater than 60 days past due or which are being contested in good faith	($________________)
4.Total Debt	$________________
B. EBITDA (amount on Line I.A.10)	$________________
C. Ratio (Line II.A.4 ÷ Line II.B)	___________ to 1.0
Maximum Permitted: 4.0 to 1.0	

III. Section 9.01(c) – Current Ratio.

A. Current Assets (including Borrowing Base availability)	$________________
B. Current Liabilities (excluding current maturities of Indebtedness owed to Lenders)	$________________
C. Ratio (Line III.A ÷ Line III.B):	__________ to 1.0
Minimum Required: 1.0 to 1.0	

EXHIBIT 21.1

Vanguard Natural Resources, LLC
OWNERSHIP LIST
as of December 31, 2008

Entity Name	Place of Incorporation	Owner	Relationship	Percentage Ownership
Trust Energy Company, LLC	Kentucky	Vanguard Natural Gas, LLC	Sole Member	100%
Ariana Energy, LLC	Tennessee	Vanguard Natural Gas, LLC	Sole Member	100%
Vanguard Natural Gas, LLC	Kentucky	Vanguard Natural Resources, LLC	Sole Member	100%
VNR Holdings, LLC	Delaware	Vanguard Natural Gas, LLC	Sole member	100%
Vanguard Permian, LLC	Delaware	Vanguard Natural Gas, LLC	Sole Member	100%

EXHIBIT 31.1

CERTIFICATION

I, Scott W. Smith, certify that:

1. I have reviewed this Annual Report on Form 10-K 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: March 11, 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 Annual Report on Form 10-K 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: March 11, 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 OF
CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Annual Report on Form 10-K of Vanguard Natural Resources, LLC (the “Company”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Scott W. Smith, Chief Executive Officer of the Company certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Scott W. Smith
Scott W. Smith

President and Chief Executive Officer
(Principal Executive Officer)

March 11, 2009

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

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

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

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

/s/ Richard A. Robert
Richard A. Robert

Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

March 11, 2009