Vanguard Natural Resources, LLC
Form 10-K
March 05, 2010

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from to .

Commission File Number 001-33756

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

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

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 o No x

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 o No x

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 x No o

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

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. o

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 filero	Accelerated filerx
Non-accelerated filero (Do not check if smaller reporting company)	Smaller reporting companyo

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

The aggregate market value of Vanguard Natural Resources, LLC common units held by non-affiliates of the registrant as of June 30, 2009 was approximately $102,762,900 based upon the New York Stock Exchange composite transaction closing price.

As of March 1, 2010, 18,416,173 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 2010 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, 2009 ("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 natural gas and oil, product price , natural gas and oil 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 compar 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, natural gas liquids and oil prices;
- the potential for additional impairment due to future decreases in natural gas, natural gas liquids and oil prices;
- uncertainties about the estimated quantities of natural gas, natural gas liquids and oil reserves, including uncertainties about the effects of the Securities and Exchange Commission's ("SEC") new rules governing reserve reporting;
- 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, natural gas liquids 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, natural gas liquids and oil;
- competition in the natural gas, natural gas liquids 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;
- the effect of legislation, regulatory initiatives and litigation related to climate change;
- 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	Mcf	= thousand cubic feet
Bbls	= barrels	Mcfe	= thousand cubic feet of natural gas equivalents
Bcf	= billion cubic feet	MGal	= thousand gallons
Bcfe	= billion cubic feet equivalents	MMBtu	= million British thermal units
Btu	= British thermal unit	MMcf	= million cubic feet
Gal	= gallons	MMcfe	= million cubic feet of natural gas equivalents
MBbls	= thousand barrels	NGL	= natural gas liquids

When we refer to natural gas, natural gas liquids and oil in “equivalents,” we are doing so to compare quantities of natural gas liquids and oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which 42 gallons is equal to one Bbl of oil or one Bbl of natural gas liquids and one Bbl of oil or one Bbl of natural gas liquids is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

References in this report to (1) “us,” “we,” “our,” “the Company,” “Vanguard” or “VNR” are to Vanguard Natural Resources, and its subsidiaries, including Vanguard Natural Gas, LLC, Trust Energy Company, LLC (“TEC”), VNR Holdings, Inc. (“VNRH”), Ariana Energy, LLC (“Ariana Energy”), Vanguard Permian, LLC (“Vanguard Permian”) and VNR Finance Corp. (“VNRF”) and (2) “Vanguard Predecessor,” “Predecessor,” “our operating subsidiary” or “VNG” are to Vanguard Natur 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 New York Stock Exchange 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 which 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), 56 gross wells (54 net wells) of which we operate. With respect to operations, we established two district offices, one in Lovington, New Mexico and the other in Christoval, Texas to manage these assets. Our operating focus has been on maximizing existing production and looking for complementary acquisitions that we can add to this operating platform. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4 million barrels of oil equivalent, 86% of which is oil and 89% of which is proved developed producing.

On July 18, 2008, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd. (“Segundo”), a wholly-owned subsidiary of the Lewis Energy Group (“Lewis”), for the acquisition of certain natural gas and oil properties located in the Dos Hermanos Field in Webb County, Texas, referred to as the "Dos Hermanos 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. 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 90 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 operates all the properties and is contractually obligated to drill seven wells each year from 2010 through 2013 unless mutually agreed not to do so. Upon closing this transaction, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from existing producing wells for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 16.0 Bcfe, 99% of which is natural gas and natural gas liquids and 59% of which is proved developed producing.

On July 17, 2009, we entered into a Purchase and Sale Agreement with Segundo to acquire certain natural gas and oil properties located in the Sun TSH Field in La Salle County, Texas for $52.3 million, referred to as the "Sun TSH acquisition." The acquisition had a July 1, 2009 effective date and was completed on August 17, 2009 for an adjusted purchase price of $50.5 million, subject to customary post-closing adjustments. An affiliate of Lewis operates all of the wells acquired in this transaction. This acquisition was funded with borrowings under our reserve-based credit facility and proceeds from the Company's public equity offering of 3.9 million common units completed on August 17, 2009. At closing, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from then-existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010, which had a fair value of $4.1 million on the closing date. In addition, concurrent with the execution of the Purchase and Sale Agreement, we entered into a collar for certain volumes in 2010 and a series of collars for a substantial portion of the expected gas production for 2011 at prices above the then-current market price with a total cost to the Company of $3.1 million, which was financed through deferred premiums. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 35.7 Bcfe, 98% of which is natural gas and natural gas liquids and 62% is proved developed producing.

On November 27, 2009, we entered into a Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and a Conveyance Agreement to acquire certain producing natural gas and oil properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million, subject to customary post-closing adjustments. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.3 million common unit offering. We will operate all but one of the ten wells acquired in this transaction. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4 million barrels of oil equivalent, 81% of which is oil and 55% is proved developed.

Based on reserve reports prepared by our independent reserve engineers, Netherland, Sewell & Associates, Inc., or "NSAI," and DeGolyer and MacNaughton, or "D&M," our total estimated proved reserves at December 31, 2009 were 142.9 Bcfe, of which approximately 73% were natural gas and natural gas liquids and 68% were classified as proved developed. At December 31, 2009, we owned working interests in 2,011 gross (1,185 net) productive wells and our average net production for the year ended December 31, 2009 was 20,010 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 12%, or 16.7 Bcfe, of our estimated proved reserves as of December 31, 2009 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 1.7% of our estimated proved developed reserves as of December 31, 2009. 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 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 and the Permian Basin, we own working interests ranging from 30-100% in approximately 16,130 undeveloped acres surrounding our existing wells.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 20 years based on our proved reserves as of December 31, 2009 and our production for 2009. As of December 31, 2009, we have identified 470 proved undeveloped drilling locations and over 205 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 until January 5, 2012 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 January 5, 2011, 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 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector appears to have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved.

During 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $22.07 on December 31, 2009. Also during 2009, we did not drill any wells on our operated properties, and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment, and only when we have sufficient liquidity to do so. Maintaining adequate liquidity may involve the issuance of debt and equity at less attractive terms, could involve the sale of non-core assets and could require reductions in our capital spending. In the near-term we will focus on maximizing returns on existing assets by managing our costs, selectively deploying capital to improve existing production and drilling a limited number of wells which we believe will provide an adequate return on the investment.

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.

Natural Gas, Natural Gas Liquids 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, 2009, 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 $0.18 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, 2009, our average realized natural gas prices in Appalachia (before hedging), represented a $1.07 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 the sale of natural gas liquids resulting from such processing, depending on the terms of the various agreements. For the year ended December 31, 2009, the average premium over NYMEX from the sale of casinghead gas plus our share of the revenues from the sale of natural gas liquids was $0.13 per MMBtu.

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 Dos Hermanos and Sun TSH properties, an affiliate of 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. During 2009, we received the average WTI price less $7.58 per barrel in Appalachia and the average WTI price less $5.55 per barrel in the Permian Basin.

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 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 for a period of time, 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, Natural Gas Liquids and Oil Data

In December 2008, the SEC adopted new rules related to modernizing reserve calculations and disclosure requirements for oil and natural gas companies, which became effective prospectively for annual reporting periods ending on or after December 31, 2009. The new rules expand the definition of oil and gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Other definitions and terms were revised, including the definition of proved reserves, which was revised to indicate that entities must use the unweighted arithmetic average of the first-day-of-the-month commodity price over the preceding 12-month period (the “12-month average price”), rather than the end-of-period price, when estimating whether reserve quantities are economical to produce. Likewise, the 12-month average price is now used to calculate cost center ceilings for impairment and to compute depreciation, depletion and amortization. Another significant provision of the new rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

The initial application of the new rules related to modernizing reserve calculations and disclosure requirements resulted in a downward adjustment of 10.6 Bcfe to our total proved reserves and a downward adjustment of $152.2 million to the standardized measure of discounted future net cash flows as of December 31, 2009. Approximately 14.2 Bcfe of this downward adjustment is attributable to the new requirement that 12-month average prices, instead of end-of-period prices, are used in estimating our quantities of proved oil and natural gas reserves. Additional proved undeveloped reserves of 3.6 Bcfe were added as a result of new SEC rules that allow for additional drilling locations to be classified as proved undeveloped reserves assuming such locations are supported by reliable technologies. No proved undeveloped reserves were removed that exceeded the five year development limitation on proved undeveloped reserves imposed by the new rules. The downward adjustment of 10.6 Bcfe to our total proved reserves due to the new SEC rules was more than offset by a 74.7 Bcfe increase in our reserves due to acquisitions completed during the year ended December 31, 2009.

Proved Reserves

The following table presents our estimated net proved natural gas, natural gas liquids and oil reserves and the present value of the estimated proved reserves at December 31, 2009, based on reserve reports prepared by NSAI and D&M. A copy of their summary reports are included as exhibits to this Annual Report. 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, natural gas liquids and oil reserves.

	As of December 31, 2009		As of December 31, 2008	
Reserve Data:				
Estimated net proved reserves:				
Natural gas (Bcf)	83.1		81.2	
Natural gas liquids (MBbls)	3,550		—	
Crude oil (MBbls)	6,413		4,547	
Total (Bcfe)	142.9		108.5	
Proved developed (Bcfe)	96.9		80.9	
Proved undeveloped (Bcfe)	46.0		27.6	
Proved developed reserves as % of total proved reserves	68	%	75	%
Standardized measure (in millions) (1)	$ 178.7		$ 190.1	
Representative Natural Gas and Oil Prices (2):				
Natural gas—Henry Hub per MMBtu	$ 3.87		$ 5.71	
Oil—WTI per Bbl	$ 61.04		$ 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 are based on spot prices per MMBtu and Bbl, respectively, calculated using the 12-month average price for January through December 2009, with these representative prices adjusted by field for quality, transportation fees and regional price differentials to arrive at the appropriate net price.

The data in the above table represents estimates only. Natural gas, natural gas liquids and oil reserve engineering is inherently a subjective process of estimating underground accumulations of natural gas, natural gas liquids and oil that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of natural gas, natural gas liquids and oil that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future sales prices may differ from those assumed in these estimates. Please read “Item 1A—Risk Factors.”

In accordance with the guidelines of the SEC, our independent reserve engineers’ estimates of future net revenues from our properties, and the standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product.

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’s (“FASB”) Accounting Standards Codification (“ASC”), 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 have 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 2009, we paid NSAI approximately $33,000 for all reserve and economic evaluations.

Qualifications of Technical Persons and Internal Controls over Reserves Estimation Process

Our proved reserve information as of December 31, 2009 included in this Annual Report was estimated by our independent petroleum engineers, NSAI and D&M, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers who work closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI and D&M in their reserves estimation process. In the fourth quarter, our technical team meets on a regular basis with representatives of NSAI and D&M to review properties and discuss methods and assumptions used in NSAI and D&M’s preparation of the year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, the NSAI reserve report and the D&M reserve report are reviewed by our senior management and internal technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis.

Reserve Technologies

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, NSAI and D&M each employed technologies that have been demonstrated to yield results with consistency and repeatability. The technical and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, production data, seismic data, well test data, historical price and cost information and property ownership interests.

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2009, as estimated by our independent petroleum engineers, were 46.0 Bcfe, consisting of 1.6 million barrels of oil, 29.0 MMcf of natural gas and 1.2 million barrels of natural gas liquids. In 2009, we developed approximately 0.5% of our total proved undeveloped reserves booked as of December 31, 2008 through the drilling of one gross (0.45 net) well at an aggregate capital cost of approximately $0.3 million. None of our proved undeveloped reserves at December 31, 2009 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves. At December 31, 2009, there are 18 locations with 3.9 Bcfe of proved undeveloped reserves in South Texas that are scheduled to be drilled on a date more than five years from the date the reserves were initially booked as proved undeveloped since we have a contractual arrangement with the operator to drill only 14 wells per year.

Production and Price History

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

	Net Production			Average Realized Sales Prices (2)			Production Cost (3)
	Crude Oil Bbls/day	Natural Gas Mcf/day	NGLs Gal/day	Crude Oil Per Bbl	Natural Gas Per Mcf	NGLs Per Gal	Per BOE
Year Ended December 31, 2009 (1)							
Sun TSH Field	26	1,124	7,095	$ 65.40	$ 11.03	$ 0.95	$ 3.76
Other	921	11,320	6,113	$ 75.54	$ 11.16	$ 0.75	$ 11.25
Total	947	12,444	13,208	$ 75.26	$ 11.15	$ 0.86	$ 10.39
Year Ended December 31, 2008 (4)							
Total other	715	11,450	3,271	$ 85.69	$ 10.49	$ 1.18	$ 11.24
Year Ended December 31, 2007							
Total other	84	11,080	—	$ 66.08	$ 8.92	$ —	$ 7.17

(1) Average daily production for 2009 calculated based on 365 days including production for the Sun TSH and Ward County acquisitions from the closing dates of these acquisitions.

(2) Average realized sales prices including hedges but excluding the non-cash amortization of premiums paid and non-cash amortization of value on derivative contracts acquired.

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

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

Productive Wells

The following table sets forth information at December 31, 2009 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	5	5	60	58	65	63
Non-operated	1,228	1,087	718	35	1,946	1,122
Total	1,233	1,092	778	93	2,011	1,185

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2009 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross (3)	Net (4)	Gross (3)	Net (4)	Gross	Net
Operated	10,247	7,376	3,430	2,874	13,677	10,250
Non-operated	30,980	28,044	122,171	52,756	153,151	80,800

(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

In Appalachia, most of our wells are drilled to depths ranging from 2,000’ to 4,500’. Many of our wells are completed to multiple producing zones and production from these zones may be commingled. The average well in Appalachia takes approximately 10 days to drill and most of our wells are producing and connected to 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. In 2009, we and our operating partner, Vinland, decided not to drill any new wells until natural gas prices improved. However, during 2009 we recompleted 12 wells to an oil zone located less than 3,000 feet in depth. The data from these recompletions has generated some additional oil drilling prospects. In 2010, we intend to drill approximately 10 net wells in Appalachia.

In the Permian Basin, we drilled no wells in 2009 on our operated properties and there was limited drilling activity on our non-operated properties. In December 2009, we acquired production and undeveloped acreage in Ward County, Texas. In 2010, we intend to drill one oil well in Ward County in which we will own a 100% working interest. This oil well will be drilled horizontally in the Bone Springs sand to a vertical depth of approximately 11,400' and is designed to drill out 4,000' laterally. This proposed oil well is offset on 3 sides with successful horizontal oil wells and the reserves for the proposed well are proved.

In South Texas, most of our wells are drilled to depths ranging from 5,500' to 7,800'. Most of the reserves are produced from Olmos gas sands. We participated (50% working interest) in drilling one Olmos sand gas well in Webb County in the fourth quarter of 2009. In August 2009, we acquired production and undeveloped acreage in the Sun TSH field in La Salle County. In 2010, we and our operating partner, Lewis Petro Properties, plan to drill up to 13 gross (6.5 net) Olmos wells in Webb and La Salle Counties. One of the wells planned for 2010 is a horizontal well in the Olmos sand.

During 2010, 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, 2009, 2008 and 2007. 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,		
	2009	2008	2007
Gross wells:			
Productive	1	86	82
Dry	—	1	1
Total	1	87	83
Net Development wells:			
Productive	0.45	38	33
Dry	—	1	—
Total	0.45	39	33
Net Exploratory wells:			
Productive	—	—	—
Dry	—	—	—
Total	—	—	—

Operations

Principal Customers

For the year ended December 31, 2009, sales of natural gas, natural gas liquids and oil to Seminole Energy Services, Osram Sylvania, Inc., Plains Marketing L.P., Sunoco Partners Marketing and Terminals, L.P. and Occidental Energy Marketing, Inc. accounted for approximately 35%, 9%, 7%, 5% and 2%, respectively, of our natural gas, natural gas liquids and oil revenues. Our top five purchasers during the year ended December 31, 2009, therefore accounted for 58% of our total revenues. To the extent these and other customers reduce the volumes of natural gas, natural gas liquids 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 may enter into 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, 2009:

	2010	2011	2012	2013
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	4,731,040	3,328,312	—	—
Fixed Price ($/MMBtu)	$ 8.66	$ 7.83	$ —	$ —
Collars:				
Notional Volume (MMBtu)	1,607,500	1,933,500	—	—
Floor Price ($/MMBtu)	$ 7.73	$ 7.34	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.92	$ 8.44	$ —	$ —
Total:				
Notional Volume (MMBtu)	6,338,540	5,261,812	—	—
Oil Positions:				
Fixed Price Swaps:				
Notional Volume (Bbls)	310,250	260,750	137,250	118,625
Fixed Price ($/Bbl)	$ 85.93	$ 86.12	$ 88.13	$ 88.42
Collars:				
Notional Volume (Bbls)	—	—	45,750	45,625
Floor Price ($/Bbl)	$ —	$ —	$ 80.00	$ 80.00
Ceiling Price ($/Bbl)	$ —	$ —	$ 100.25	$ 100.25
Total:				
Notional Volume (Bbls)	310,250	260,750	183,000	164,250

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 obligations to fixed interest rates.

The following summarizes information concerning our positions in open interest rate swaps at December 31, 2009.

	Notional Amount	Fixed Libor Rates
Period:		
January 1, 2010 to December 18, 2010	$ 10,000,000	1.50%
January 1, 2010 to December 20, 2010	$ 10,000,000	1.85%
January 1, 2010 to January 31, 2011	$ 20,000,000	3.00% (1)
January 1, 2010 to March 31, 2011	$ 20,000,000	2.08%
January 1, 2010 to December 10, 2012	$ 20,000,000	3.35%
January 1, 2010 to January 31, 2013	$ 20,000,000	2.38%

(1) In February 2010, we extended the terms of the 3.00%, $20.0 million interest rate swap for two additional years to January 31, 2013 and reduced the rate from 3.00% to 2.66%.

Counterparty Risk

At December 31, 2009, 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 S&P financial strength rating in parentheses (in thousands):

	Citibank, N.A. (A+)	BNP Paribas (AA)	The Bank of Nova Scotia (AA-)	Wells Fargo Bank N.A./Wachovia Bank, N.A. (AA)	BBVA Compass (A+)	Total
Current Assets	$ 3,912	$ 10,641	$ —	$ 1,570	$ 67	$ 16,190
Current Liabilities	$ (92)	$ —	$ (161)	$ —	$ —	$ (253)
Long-Term Assets	$ 1,393	$ 3,745	$ 87	$ —	$ —	$ 5,225
Long-Term Liabilities	$ —	$ (1,040)	$ (592)	$ (402)	$ (2)	$ (2,036)
Total Amount Due from/(Owed To) Counterparty at December 31, 2009	$ 5,213	$ 13,346	$ (666)	$ 1,168	$ 65	$ 19,126

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 has caused significant price increases. We are unable to predict when, or if, such shortages may occur or how they would affect our development program.

Competition is also strong for attractive natural gas and oil 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, natural gas liquids and oil by, among other things, limiting the amount of natural gas, natural gas liquids 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, 2009, 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 2010 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 production activities, as well as proposed 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 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, natural gas liquids 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, natural gas liquids 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, natural gas liquids 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, or the "NGA". 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 and natural gas liquids 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 just and reasonable rates published in agency-approved tariffs and require pipelines to provide non-discriminatory access and terms and conditions of service. The justness and reasonableness of interstate oil and natural gas liquid pipeline rates can be challenged at FERC through a protest or a complaint and, if such a protest or complaint results in a lower rate than that on file, pipeline shippers may be eligible to receive refunds or, in the case of a complaining shipper, reparations for the two-year period prior to the filing of the complaint. 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 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 and the Natural Gas Policy Act 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 discussed below 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.

In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report on Form No. 552, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Pursuant to Order 704, we may be required to annually report to FERC, starting May 1 information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted during the prior calendar year.

On August 6, 2009, the Federal Trade Commission, or "FTC", issued a Final Rule prohibiting manipulative and deceptive conduct in the wholesale petroleum markets. The Final Rule applies to transactions in crude oil, gasoline, and petroleum distillates. The FTC promulgated the Final Rule pursuant to Section 811 of the Energy Independence and Security Act of 2007 ("EISA"), which makes it unlawful for anyone, in connection with the wholesale purchase or sale of crude oil, gasoline, or petroleum distillates, to use any "manipulative or deceptive device or contrivance, in contravention of such rules and regulations as the Federal Trade Commission may prescribe." The Final Rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline, or petroleum distillates at wholesale, from: a) knowingly engaging in any act, practice, or course of business – including making any untrue statement of material fact that operates or would operate as a fraud or deceit upon any person; or b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas companies with whom we compete.

The price at which we buy and sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission, or “CFTC”. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

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.

The various states regulate the drilling for, and the production, gathering and sale of, natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquids 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, 2009, we had twelve full time employees. Nine of our employees work in our Houston office, two employees work in our office in Lovington, New Mexico and one employee works in our office in Christoval, Texas. Under a 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, Dos Hermanos, Sun TSH and Ward County acquisitions, we outsource the production accounting to a third party and operate 56 gross wells (54 net wells) in the Permian Basin. With respect to the Dos Hermanos and Sun TSH properties, an affiliate of Lewis 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 new lease agreement in February 2010 for approximately 7,982 square feet of office space in Houston, Texas. The new lease for our Houston office expires in February 2013.

Available Information

Our website address is www.vnrllc.com. We make our website content available for information purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. We make available on this website under "Investor Relations-SEC Filings," free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. The SEC also maintains a website at www.sec.gov that contains reports, proxy statements and other information regarding SEC registrants, including us.

You may also find information related to our corporate governance, board committees and company code of business conduct and ethics on our website. Among the information you can find there is the following:

- Audit Committee Charter;
- Nominating and Corporate Governance Committee Charter;
- Compensation Committee Charter;
- Conflicts Committee Charter;
- Code of Business Conduct and Ethics, and
- Corporate Governance Guidelines.

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, natural gas liquids and oil we produce;
- the price at which we are able to sell our natural gas, natural gas liquids 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.

Our estimates of proved reserves have been prepared under new SEC rules which went into effect for fiscal years ending on or after December 31, 2009, which may make comparisons to prior periods difficult and could limit our ability to book additional proved undeveloped reserves in the future.

This report presents estimates of our proved reserves as of December 31, 2009, which have been prepared and presented under new SEC rules. These new rules are effective for fiscal years ending on or after December 31, 2009, and require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on the twelve-month average price. The previous rules required that reserve estimates be calculated using last-day-of the-year pricing. The pricing that was used for estimates of our reserves as of December 31, 2009 was based on the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil, as compared to $5.71 per MMBtu for natural gas and $41.00 per Bbl for oil as of December 31, 2008. As a result of these changes, direct comparisons to our previously-reported reserves amounts may be more difficult.

Another impact of the new SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This new rule has limited and may continue to limit our potential to book additional proved undeveloped reserves as we pursue our drilling program, particularly as we develop our significant acreage in the Permian Basin, South Texas and Appalachia. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe.

The SEC has not reviewed our or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules,
those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

We may not be able to 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 while the availability of funds from those markets generally has diminished. 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 pursue 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, natural gas liquids and oil reserves, which will take into account the prevailing natural gas, natural gas liquids 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 December 2009, our borrowing base was set at $195.0 million. Our next borrowing base redetermination is scheduled for April 2010 utilizing our December 31, 2009 reserve report.

A future decline in commodity prices could result in a redetermination lowering our 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, natural gas liquids and oil prices are volatile. A decline in natural gas, natural gas liquids 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, natural gas liquids and oil production and the prices prevailing from time to time for natural gas, natural gas liquids 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 volatility in natural gas, natural gas liquids and oil prices has impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. 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, natural gas liquids and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical and economic conditions. For example, the crude oil spot price per barrel for the period between January 1, 2009 and December 31, 2009 ranged from a high of $81.03 to a low of $34.03 and the NYMEX natural gas spot price per MMBtu for the period January 1, 2009 to December 31, 2009 ranged from a high of $6.07 to a low of $2.51. As of February 23, 2010, the crude oil spot price per barrel was $78.61 and the NYMEX natural gas spot price per MMBtu was $4.78. 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, natural gas liquids and oil are subject to a variety of factors, including:

- the level of consumer demand for natural gas, natural gas liquids and oil;
- the domestic and foreign supply of natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquids and oil prices would not only reduce our revenue, but could reduce the amount of natural gas, natural gas liquids 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, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The Securities and Exchange Commission's ("SEC") Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. 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, natural gas liquids and oil prices may not only decrease our revenues, but also reduce the amount of natural gas, natural gas liquids 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, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. 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, natural gas liquids 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, natural gas liquids and oil prices were very volatile throughout 2009. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oilof $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. 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. Based on the 12-month average natural gas and oil prices through February 2010, we do not anticipate an impairment at March 31, 2010.

Our acquisition activities will subject us to certain risks.

During 2008 and 2009, 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.

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.

Vinland controls our drilling program in Appalachia. Should we ask them to, Vinland has agreed to drill not less than 100 gross wells over the next year.

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, natural gas liquids and oil production that may be produced from such wells. Notwithstanding the foregoing, if both parties agree, no drilling is required.

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 declares bankruptcy, 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, natural gas liquids 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 and oil prices declined by $6.00 per barrel, the standardized measure of our proved reserves as of December 31, 2009 would decrease from $178.7 million to $115.8 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 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, natural gas liquids 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 using a 12-month average price 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, natural gas liquids and oil;
- actual prices we receive for natural gas, natural gas liquids and oil;
- our actual operating costs in producing natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquids and oil we are able to produce from existing wells;
- the prices at which our natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquids and oil 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, natural gas liquids and oil we produce and could reduce our revenues and cash available for distribution.

The marketability of our natural gas, natural gas liquids and oil 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.

Our sales of natural gas, natural gas liquids, oil and other energy commodities, and related hedging activities, expose us to potential regulatory risks.

The FTC, FERC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas, natural gas liquids, oil or other energy commodities, and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We are subject to FERC requirements related to our use of capacity on natural gas pipelines that are subject to FERC regulation. Any failure on our part to comply with the FERC's regulations and policies, or with an interstate pipeline's tariff, could result in the imposition of civil and criminal penalties.

Climate change legislation, regulatory initiatives and litigation may adversely affect our operations, our cost structure, or the demand for oil and gas.

On April 17, 2009, the U.S. Environmental Protection Agency, or "EPA," issued a notice of its proposed finding and determination that emissions of carbon dioxide, methane, and other greenhouse gases, or "GHGs," presented an endangerment to human health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere. Once finalized, EPA's finding and determination would allow it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. Although it may take EPA several years to adopt and impose regulations limiting emissions of GHGs, any limitation on emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, on June 26, 2009, the U.S. House of Representatives passed House Bill 2454, also referred to as the "Waxman-Markey legislation" but formally named the "American Clean Energy and Security Act of 2009," which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of carbon dioxide and other GHGs by 17 percent from 2005 levels by 2020 and just over 80 percent by 2050. President Obama is encouraging the Senate to consider climate change legislation during the fall of 2009. Further, on September 21, 2009 a U.S. Federal appellate court reinstated a lawsuit filed by several state attorneys general and others against five of the largest U.S. electric utility companies alleging that those companies have created a public nuisance due to their emissions of carbon dioxide. Although it is not possible at this time to predict if and when the Senate may act on climate change legislation, how any bill passed by the Senate would be reconciled with House Bill 2454 or what effect, if any, the recent decision permitting a nuisance lawsuit to proceed against certain utilities may have on the oil and gas industry, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions, as well as future climate change litigation against us or our customers for GHG emissions, could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the natural gas, natural gas liquids and oil we produce.

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

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is considering whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Separately, the House of Representatives adopted financial regulatory reform legislation on December 11, 2009, that, among other things, would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace. This legislation would subject swap dealers and "major swap participants" to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants, and would provide the CFTC with authority to impose position limits in the OTC derivatives markets. A major swap participant generally would be someone other than a dealer who maintains a "substantial" net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the US banking system or financial markets. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

We depend on certain key customers for sales of our natural gas, natural gas liquids and oil. To the extent these and other customers reduce the volumes of natural gas, natural gas liquids 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, 2009, sales of natural gas, natural gas liquids and oil to Seminole Energy Services, Osram Sylvania, Inc., Plains Marketing L.P., Sunoco Partners Marketing and Terminals, L.P. and Occidental Energy Marketing, Inc. accounted for approximately 35%, 9%, 7%, 5% and 2%, respectively, of our natural gas, natural gas liquids and oil revenues. Our top five purchasers during the year ended December 31, 2009, therefore accounted for 58% of our total revenues. To the extent these and other customers reduce the volumes of natural gas, natural gas liquids 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;
- 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.

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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, 2009, we have identified 470 proved undeveloped drilling locations and over 205 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 and D&M have not assigned any proved reserves to the over 205 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, natural gas liquids 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, natural gas liquids and oil prices for prolonged periods and resulting decreases in our borrowing base may force us to reduce or suspend distributions to our unitholders.

If 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 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., (“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 1.7% of our proved developed reserves as of December 31, 2009. 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, natural gas liquids 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, natural gas liquids 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 th 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, natural gas liquids 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. In the past, we and other natural gas, natural gas liquids 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, natural gas liquids 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 15.2% of our outstanding common units 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.

Conflicts of interest may arise between Nami and his affiliates, including Vinland, 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 may differ from interests of owners of units include, among others, the following situations:

- 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 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $22.07 on December 31, 2009. 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 1.7% of our estimated proved developed reserves as of December 31, 2009. 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. RESERVED

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 New York Stock Exchange under the symbol “VNR.” On March 1, 2010, there were 18,416,173 common units outstanding and approximately twelve unitholders, which does not include beneficial owners whose units are held by a clearing agency, such as a broker or a bank. On March 1, 2010, the market price for our common units was $24.90 per unit, resulting in an aggregate market value of units held by non-affiliates of approximately $389,091,708. The following table presents the high and low sales price for our common units during the periods indicated.

	Common Units	
	High	Low
2009		
Fourth Quarter	$ 22.80	$ 14.47
Third Quarter	$ 16.73	$ 11.97
Second Quarter	$ 15.15	$ 9.88
First Quarter	$ 11.24	$ 5.90
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

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 for 2007 and 2008. For 2009, the Peer Group Index was a weighted composite of five natural gas and oil production publicly traded partnerships, which were paying a distribution for all of 2009. 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 New York Stock Exchange ($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	December 31, 2009
Vanguard Natural Resources, LLC	$ 100	$ 84.48 (1)	$ 35.37 (1)	$ 154.88 (1)
Peer Group Index	$ 100	$ 90.76	$ 42.75	$ 119.50
S&P 500 Index	$ 100	$ 96.87	$ 59.59	$ 73.56

(1) Based on the last reported sale price of VNR units as reported by New York Stock Exchange on December 31, 2007 ($16.00), 2008 ($5.90) and 2009 ($22.07).

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
2009				
Fourth Quarter	$	0.525	February 5, 2010	February 12, 2010
Third Quarter	$	0.500	November 6, 2009	November 13, 2009
Second Quarter	$	0.500	July 31, 2009	August 14, 2009
First Quarter	$	0.500	April 30, 2009	May 15, 2009
2008				
Fourth Quarter	$	0.500	January 30, 2009	February 17, 2009
Third Quarter	$	0.500	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

Our limited liability company agreement requires that, within 45 days after the end of each quarter, 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, 2009.

Unregistered Sale of Equity Securities and Use of Proceeds. During the three months ended December 31, 2009, one of our wholly-owned subsidiaries purchased 31,000 of our common units on the open market at the prevailing market price. The following table summarizes the unit purchases that occurred during the three months ended December 31, 2009:

Period	Number of common units repurchased	Average price paid per common unit
October 1, 2009 to October 31, 2009	10,000	$ 17.54
November 1, 2009 to November 30, 2009	11,000	$ 17.15
December 1, 2009 to December 31, 2009	10,000	$ 18.24
Total common units purchased	31,000	$ 17.63

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, 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.

Comparability of Our Financial Statements to Our Predecessor

The historical financial statements of our Predecessor included in this Annual Report 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 ASC Topic 815 "Derivatives and Hedging" ("ASC Topic 815") as we did in 2007. 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 and 2009, 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.

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 Annual Report.

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) (8) (9)				
	Vanguard			Vanguard Predecessor	
(in thousands, except per unit data)	2009	2008	2007	2006	2005
Statement of Operations Data:					
Revenues:					
Natural gas, natural gas liquids and oil sales	$ 46,035	$ 68,850	$ 34,541	$ 38,184	$ 40,299
Gain (loss) on commodity cash flow hedges (1)	(2,380)	269	(702)	—	—
Realized gain (loss) on other commodity derivative contracts (1)	29,993	(6,552)	—	(2,208)	(10,024)
Unrealized gain (loss) on other commodity derivative contracts (1)	(19,043)	39,029	—	17,748	(18,779)
Other	—	—	—	665	451
Total revenues	54,605	101,596	33,839	54,389	11,947
Costs and Expenses:					
Lease operating expenses	12,652	11,112	5,066	4,896	4,607
Depreciation, depletion, amortization and accretion	14,610	14,910	8,981	8,633	6,189
Impairment of natural gas and oil properties	110,154	58,887	—	—	—
Selling, general and administrative expenses	10,644(2)	6,715 (2)	3,507	5,199	5,946
Bad debt expense	—	—	1,007	—	—
Production and other taxes	3,845	4,965	2,054	1,774	1,249
Total costs and expenses	151,905	96,589	20,615	20,502	17,991
Income (Loss) from Operations:	(97,300)	5,007	13,224	33,887	(6,044)
Other Income and (Expenses):					
Interest income	—	17	62	40	52
Interest and financing expenses	(4,276)	(5,491)	(8,135)	(7,372)	(4,566)

Gain on acquisition of natural gas and oil properties	6,981	—	—	—	—
Realized loss on interest rate derivative contracts	(1,903)	(107)	—	—	—
Unrealized gain (loss) on interest rate derivative contracts	763	(3,178)	—	—	—
Loss on extinguishment of debt	—	—	(2,502)	—	—
Total other income (expenses)	1,565	(8,759)	(10,575)	(7,332)	(4,514)
Net income (loss)	$ (95,735)	$ (3,752)	$ 2,649	$ 26,555	$ (10,558)
Net income (loss) per unit:					
Common and Class B units- basic & diluted	$ (6.74)	$ (0.32)	$ 0.39	N/A (3)	N/A (3)
Distributions declared per unit	$ 2.00	$ 1.77(4)	$ 0.425(4)	N/A (3)	N/A (3)
Weighted average common units outstanding	13,791	11,374	6,533	N/A (3)	N/A (3)
Cash Flow Data:					
Net cash provided by operating activities (1)	$ 52,155	$ 39,554	$ 1,373	$ 16,087	$ 10,530
Net cash used in investing activities	(109,315)	(119,539)	(26,409)	(37,383)	(37,068)
Net cash provided by financing activities	57,644	76,878	26,415	19,985	25,571
Other Financial Information:					
Adjusted EBITDA (5)	$ 56,202	$ 48,754	$ 30,395	$ 24,772	$ 18,924

(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 ASC Topic 815, 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 and 2009, 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.

(2) Includes $2.9 million, $3.6 million and $2.1 million of non-cash unit-based compensation expense in 2009, 2008 and 2007, respectively.

(3) No dividends declared per unit and no calculations of earnings per unit and weighted average units outstanding were made for the Vanguard Predecessor as there was a single member interest prior to 2007.

(4) Distributions declared per unit for 2008 were calculated using total distributions to members of $20.1 million over the weighted average common units for the year. The 2007 distribution was pro-rated for the period from the closing of the IPO on October 28, 2007 through December 31, 2007, resulting in a distribution of $0.291 per unit for the period.

(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 and 2005.

(7) The Dos Hermanos 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 and 2005.

(8) The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately four and one half months of operations are included in the year ended December 31, 2009 and were not included in the results of 2008, 2007, 2006 and 2005.

(9) The Ward County acquisition closed on December 2, 2009 and, as such, only one month of operations is included in the year ended December 31, 2009 and no operations are included in the results of 2008, 2007, 2006 and 2005.

(in thousands)	As of December 31, (1) (2)				
		Vanguard		Vanguard Predecessor	
	2009	2008	2007	2006	2005
Balance Sheet Data:					
Cash and cash equivalents	$ 487	$ 3	$ 3,110	$ 1,731	$ 3,041
Short-term derivative assets	16,190	22,184	4,017	—	—
Other current assets	11,566	9,691	4,826	20,438	19,598
Natural gas and oil properties, net of accumulated depreciation, depletion, amortization and accretion	172,525	182,269	106,983	104,684	83,513
Property, plant and equipment, net of accumulated depreciation	174	184	166	11,873	4,104
Long-term derivative assets	5,225	15,749	1,330	—	—
Other assets	4,533	2,482	10,747	—	—
Total Assets	$ 210,700	$ 232,562	$ 131,179	$ 138,726	$ 110,256
Short-term derivative liabilities	$253	$486	$—	$2,022	$11,527
Other current liabilities	12,166	7,278	5,355	11,505	12,033
Long-term debt	129,800	135,000	37,400	94,068	72,708
Long-term derivative liabilities	2,036	2,313	5,903	—	8,243
Other long-term liabilities	6,159	2,134	190	418	212
Members’ equity	60,286	85,351	82,331	30,713	5,533
Total Liabilities and Members’ Equity	$210,700	$232,562	$131,179	$138,726	$110,256

(1) The Permian acquisition closed on January 31, 2008 and the Dos Hermanos acquisition closed on July 28, 2008.

(2) The Sun TSH acquisition closed on August 17, 2009 and the Ward County acquisition closed on December 2, 2009.

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 D&M, and certain summary unaudited information with respect to our production and sales of natural gas, natural gas liquids 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, Natural Gas Liquids and Oil Data—Proved Reserves” and “—Production and Price History” included in this Annual Report in evaluating the material presented below.

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	As of December 31, 2009	As of December 31, 2008
Reserve Data:		
Estimated net proved reserves:		
Natural gas (Bcf)	83.1	81.2
Natural gas liquids (MBbls)	3,550	—
Crude oil (MBbls)	6,413	4,547
Total (Bcfe)	142.9	108.5
Proved developed (Bcfe)	96.9	80.9
Proved undeveloped (Bcfe)	46.0	27.6
Proved developed reserves as % of total proved reserves	68 %	75 %
Standardized measure (in millions) (1)	$ 178.7	$ 190.1
Representative Natural Gas and Oil Prices (2):		
Natural gas—Henry Hub per MMBtu	$ 3.87	$ 5.71
Oil—WTI per Bbl	$ 61.04	$ 41.00

(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 the 12-month average price) 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) Natural gas and oil prices are based on spot prices per MMBtu and Bbl, respectively, calculated using the 12-month average price for January through December 2009, with these representative prices adjusted by field for quality, transportation fees and regional price differentials to arrive at the appropriate net price.

	Net Production			Average Realized Sales Prices (2)			Production Cost (3)
	Crude Oil Bbls/day	Natural Gas Mcf/day	NGLs Gal/day	Crude Oil Per Bbl	Natural Gas Per Mcf	NGLs Per Gal	Per BOE
Year Ended December 31, 2009 (1)							
Sun TSH Field	26	1,124	7,095	$ 65.40	$ 11.03	$ 0.95	$ 3.76
Other	921	11,320	6,113	$ 75.54	$ 11.16	$ 0.75	$ 11.25
Total	947	12,444	13,208	$ 75.26	$ 11.15	$ 0.86	$ 10.39
Year Ended December 31,							

2008 (4)							
Total other	715	11,450	3,271	$ 85.69	$ 10.49	$ 1.18	$ 11.24
Year Ended December 31, 2007							
Total other	84	11,080	—	$ 66.08	$ 8.92	$ —	$ 7.17

(1) Average daily production for 2009 calculated based on 365 days including production for the Sun TSH and Ward County acquisitions from the closing dates of these acquisitions.

(2) Average realized sales prices including hedges but excluding the non-cash amortization of premiums paid and non-cash amortization of value on derivative contracts acquired.

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

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

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 on derivative contracts;
- Amortization of value on derivative contracts acquired;
- Unrealized gains and losses on other commodity and interest rate derivative contracts;
- Gains and losses on acquisitions of natural gas and oil properties;
- Change in fair value of derivative contracts;
- Deferred taxes;
- Unit-based compensation expense;
- Realized gains and losses on cancelled derivatives; and
- Non-cash portion of phantom unit expense granted to officers.

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:
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	Year Ended December 31, (in thousands)				
	Vanguard			Vanguard Predecessor	
(in thousands)	2009	2008	2007	2006	2005
Net Income (Loss)	$ (95,735)	$ (3,752)	$ 2,649	$ 26,555	$ (10,558)
Plus:					
Interest expense, including realized losses on interest rate derivative contracts	6,179	5,597	8,135	7,372	4,566
Loss on extinguishment of debt	—	—	2,502	—	—
Depreciation, depletion, amortization and accretion	14,610	14,910	8,981	8,633	6,189
Impairment of natural gas and oil properties	110,154	58,887	—	—	—
Bad debt expense	—	—	1,007	—	—
Amortization of premiums paid on derivative contracts	3,502	4,493	4,274	—	—
Amortization of value on derivative contracts acquired	3,619	733	—	—	—
Unrealized (gains) losses on other commodity and interest rate derivative contracts (1)	18,280	(35,851)	—	(17,748)	18,779
Gain on acquisitions of natural gas and oil properties	(6,981)	—	—	—	—
Deferred taxes	(302)	177	—	—	—
Unit-based compensation expense	2,483	3,577	2,132	—	—
Realized loss on cancelled derivatives	—	—	777	—	—
Fair value of phantom units granted to officers	4,299	—	—	—	—
Cash settlement of phantom units granted to officers	(3,906)	—	—	—	—
Less:					
Interest income	—	17	62	40	52
Adjusted EBITDA	$ 56,202	$ 48,754	$ 30,395	$ 24,772	$ 18,924

(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 ASC Topic 815, 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 is recorded in earnings and classified as loss on interest rate derivative contracts.

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

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. 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 Repor, 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, 2009, 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, 2009, we owned working interests in 2,011 gross (1,185 net) productive wells. In addition to these productive wells, we own leasehold acreage allowing us to drill new wells. As of December 31, 2009, 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 and the Permian Basin we own working interests ranging from 30-100% in approximately 16,130 undeveloped acres surrounding our existing wells. Approximately 32% or 46.0 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.

Shelf Registration Statement

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

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

As a result of these offerings, we have approximately $197.4 million remaining available under our 2009 shelf registration statement as of December 31, 2009.

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, 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 which 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), 56 gross wells (54 net wells) of which we operate. With respect to operations, we established two district offices, one in Lovington, New Mexico and the other in Christoval, Texas to manage these assets. Our operating focus has been on maximizing existing production and looking for complementary acquisitions that we can add to this operating platform. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4

million barrels of oil equivalent, 86% of which is oil and 89% of which is proved developed producing.

Dos Hermanos Acquisition

On July 18, 2008, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd. ("Segundo"), 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 "Dos Hermanos 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. 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 90 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 2010 through 2013 unless mutually agreed not to do so. Upon closing this transaction, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from existing producing wells for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 16.0 Bcfe, 99% of which is natural gas and natural gas liquids and 59% of which is proved developed producing.

Sun TSH Acquisition

On July 17, 2009, we entered into a Purchase and Sale Agreement to acquire certain natural gas and oil properties located in the Sun TSH Field in La Salle County, Texas for $52.3 million from Segundo, referred to as the "Sun TSH acquisition." The acquisition had a July 1, 2009 effective date and was completed on August 17, 2009 for an adjusted purchase price of $50.5 million, subject to customary post-closing adjustments. An affiliate of Lewis operates all of the wells acquired in this transaction. This acquisition was funded with borrowings under our reserve-based credit facility and proceeds from the Company's public equity offering of 3.9 million common units completed on August 17, 2009. At closing, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August of 2009 through December of 2010, which had a fair value of $4.1 million on the closing date. In addition, concurrent with the execution of the Purchase and Sale Agreement, we entered into a collar for certain volumes in 2010 and a series of collars for a substantial portion of the expected gas production for 2011 at prices above the then current market with a total cost to the Company of $3.1 million which was financed through deferred premiums. Inclusive of the hedges added, approximately 90% of the estimated gas production from existing producing wells in the acquired properties is hedged through 2011. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 35.7 Bcfe, 98% of which is natural gas and natural gas liquids and 62% is proved developed producing.

Ward County Acquisition

On November 27, 2009, we entered into a Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and a Conveyance Agreement to acquire certain producing natural gas and oil properties located in Ward County, Texas in the Permian Basin from private sellers, referred to as the "Ward County acquisition." This transaction had an effective date of October 1, 2009 and was closed on December 2, 2009 for $55.0 million, subject to customary post-closing adjustments. This acquisition was initially funded with borrowings under our reserve-based credit facility with borrowings being reduced by $40.3 million shortly thereafter with the proceeds from a 2.3 million common unit offering. We will operate all but one of the ten wells acquired in this transaction. As of December 31, 2009, based on a reserve report prepared by our independent reserve engineers, these acquired properties have estimated proved reserves of 3.4 million barrels of oil equivalent, 81% of which is oil and 55% is proved developed. In an effort to support stable cash flows from this transaction, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013.

Disruption to Functioning of Capital Markets

Multiple events during 2008 and 2009 involving numerous financial institutions have effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

During 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $22.07 on December 31, 2009. Also during 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. Maintaining adequate liquidity may involve the issuance of debt and equity at less attractive terms, could involve the sale of non-core assets and could require reductions in our capital spending. In the near-term we will focus on maximizing returns on existing assets by managing our costs, selectively deploying capital to improve existing production and drilling a limited number of wells which we believe will provide an adequate return on the investment.

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, 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.

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 1.7% of our estimated proved reserves as of December 31, 2009. 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. Additional borrowings under our reserve-based credit facility were made in January 2008 in connection with the acquisition of natural gas and oil properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserve-based credit facility was amended in anticipation of a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. In July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the Dos Hermanos acquisition. In October 2008, we amended our reserve-based credit facility which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, a third amendment was entered into which amended covenants to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due the Ward County acquisition. Indebtedness under the reserve-based credit facility totaled $129.8 million at December 31, 2009, and the applicable margins and other fees increase as the utilization of the borrowing base increases as follows:

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

Our next borrowing base redetermination is scheduled for April 2010 utilizing our December 31, 2009 reserve report. A 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. Until the redetermination occurs, the amount of the potential reduction is uncertain; however, we do not anticipate that any reduction will be material to the borrowing base as a whole and would not inhibit our ability to make distributions to our unitholders.

Outlook

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as access to capital, economic, political and regulatory developments, and competition from other sources of energy. Multiple events during 2008 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector appears to have improved the situation. As evidenced by our recent successful equity offering, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

During 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $22.07 on December 31, 2009. Also during 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. Maintaining adequate liquidity may involve the issuance of debt and equity at less attractive terms, could involve the sale of non-core assets and could require reductions in our capital spending. In the near-term we will focus on maximizing returns on existing assets by managing our costs, selectively deploying capital to improve existing production and drilling a limited number of wells which we believe will provide an adequate return on the investment.

Natural gas, natural gas liquids and oil prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for natural gas, natural gas liquids or oil could materially and adversely affect our financial position, our results of operations, the quantities of natural gas, natural gas liquids and oil reserves that we can economically produce, our access to capital and our ability to pay a distribution. We have mitigated the volatility on our cash flows with natural gas price derivative contracts through 2011 and oil price derivative contracts through 2013. These hedges are placed on a portion of our proved producing and a portion of our total anticipated production during this time frame. As natural gas, natural gas liquids and oil prices fluctuate, we will recognize non-cash, unrealized gains and losses in our consolidated statement of operations related to the change in fair value of our commodity derivative contracts.

We face the challenge of natural gas, natural gas liquids and oil production declines. As a given well’s initial reservoir pressures are depleted, natural gas, natural gas liquids and oil production decreases, thus reducing our total reserves. We attempt to overcome this natural decline both by drilling on our properties and acquiring additional reserves. We will maintain our focus on controlling costs to add reserves through drilling and acquisitions, as well as controlling the corresponding costs necessary to produce such reserves. During the year ended December 31, 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including the ability to timely obtain drilling permits and regulatory approvals and voluntary reductions in capital spending in a low commodity price environment. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of our production, which may have an adverse effect on our revenues and as a result, cash available for distribution. In accordance with our business plan, we intend to invest the capital necessary to maintain our production at existing levels over the long-term provided that it is economical to do so based on the commodity price environment. However, we cannot be certain that we will be able to issue equity or debt 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. The next scheduled redetermination of our borrowing base is April 2010.

Results of Operations

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

	Year Ended December 31, (1) (2) (3) (4)		
	2009	2008	2007
		(in thousands)	
Revenues:			
Gas sales	$ 21,966	$ 43,502	$ 32,517
Natural gas liquids sales	4,129	1,418	—
Oil sales	19,940	23,930	2,024
Natural gas, natural gas liquids and oil sales	46,035	68,850	34,541
Gain (loss) on commodity cash flow hedges	(2,380)	269	(702)
Realized gain (loss) on other commodity derivative contracts	29,993	(6,552)	—(5)
Unrealized gain (loss) on other commodity derivative contracts	(19,043)	39,029	—(5)
Total revenues	$ 54,605	$ 101,596	$ 33,839
Costs and expenses:			
Lease operating expenses	$ 12,652	$ 11,112	$ 5,066
Depreciation, depletion, amortization and accretion	14,610	14,910	8,981
Impairment of natural gas and oil properties	110,154	58,887	—
Selling, general and administrative expenses	10,644	6,715	3,507
Bad debt expense	—	—	1,007
Production and other taxes	3,845	4,965	2,054
Total costs and expenses	$ 151,905	$ 96,589	$ 20,615
Other income and expenses:			
Interest expense, net	$ (4,276)	$ (5,474)	$ (8,073)
Gain on acquisition of natural gas and oil properties	$ 6,981	$ —	$ —
Realized loss on interest rate derivative contracts	$ (1,903)	$ (107)	$ —
Unrealized gain (loss) on interest rate derivative contracts	$ 763	$ (3,178)	$ —
Loss on extinguishment of debt	$ —	$ —	$ (2,502)

(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.

(2) The Dos Hermanos 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.

(3) The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately four and one half months of operations are included in the year ended December 31, 2009 and were not included in the results of 2008 and 2007.

(4) The Ward County acquisition closed on December 2, 2009 and, as such, only one month of operations is included in the year ended December 31, 2009 and no operations are included in the results of 2008 and 2007.

(5) In 2007, we designated all commodity derivative contracts as cash flow hedges; therefore, all unrealized gains or losses were deferred in accumulated other comprehensive income (loss) in the equity section of the consolidated balance sheet.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenues

Natural gas, natural gas liquids and oil sales decreased $22.8 million to $46.0 million during the year ended December 31, 2009 as compared to the same period in 2008. The key revenue measurements were as follows:

	Year Ended December 31, 2009	Year Ended December 31, 2008	Percentage Increase (Decrease)
Net Natural Gas Production:			
Appalachian gas (MMcf)	3,103	3,578	(13)%
Permian gas (MMcf)	225 (1)	185 (2)	22%
South Texas gas (MMcf)	1,214 (3)	428 (4)	184%
Total natural gas production (MMcf)	4,542	4,191	8%
Average Appalachian daily gas production (Mcf/day)	8,502	9,777	(13)%
Average Permian daily gas production (Mcf/day)	616 (1)	505 (2)	22%
Average South Texas daily gas production (Mcf/day)	3,326 (3)	1,168 (4)	185%
Average Vanguard daily gas production (Mcf/day)	12,444	11,450	9%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$11.15 (5)	$10.49 (5)	6%
Net realized gas price, excluding hedges	$4.84	$10.38	(53)%
Net Oil Production:			
Appalachian oil (Bbls)	93,713	48,977	91%
Permian oil (Bbls)	242,301 (1)	212,599 (2)	14%
South Texas oil (Bbls)	9,386 (3)	—	N/A
Total oil production (Bbls)	345,400	261,576	32%
Average Appalachian daily oil production (Bbls/day)	257	134	92%
Average Permian daily oil production (Bbls/day)	664 (1)	581 (2)	14%
Average South Texas daily oil production (Bbls/day)	26 (3)	—	N/A
Average Vanguard daily oil production (Bbls/day)	947	715	32%
Average Oil Sales Price per Bbl:			

Net realized oil price, including hedges	$75.26 (5)	$85.69 (5)	(12)%
Net realized oil price, excluding hedges	$57.73	$91.48	(37)%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	454,940 (1)	231,280 (2)	97%
South Texas natural gas liquids (Gal)	4,366,016 (3)	965,718 (4)	352%
Total natural gas liquids production (Gal)	4,820,956	1,196,998	303%
Average Permian daily natural gas liquids production (Gal/day)	1,247 (1)	632 (2)	97%
Average South Texas daily natural gas liquids production (Gal/day)	11,961 (3)	2,639 (4)	353%
Average Vanguard daily natural gas liquids production (Gal/day)	13,208	3,271	304%
Average Natural Gas Liquids Sales Price per Gal:			
Net realized natural gas liquids price	$0.86	$1.18	(27)%

(1) Includes production from the Permian Basin and Ward County acquisitions. The Ward County acquisition closed on December 2, 2009 and, as such, only approximately one month of operations is included in the year ended December 31, 2009. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Ward County acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 309 Mcf/day of natural gas, 411 Bbls/day of oil and 3,330 Gal/day of natural gas liquids during 2009.

(2) The Permian Basin acquisition closed on January 31, 2008 and, as such, only eleven months of operations are included in the year ended December 31, 2008. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Permian Basin acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 552 Mcf/day of natural gas, 635 Bbls/day of oil and 690 Gal/day of natural gas liquids during 2008.

(3) Includes production from Dos Hermanos and Sun TSH acquisitions. The Sun TSH acquisition closed on August 17, 2009 and, as such, only approximately four and one half months of operations are included in the year ended December 31, 2009. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Sun TSH acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 2,995 Mcf/day of natural gas, 69 Bbls/day of oil and 18,904 Gal/day of natural gas liquids during 2009.

(4) The Dos Hermanos acquisition closed on July 28, 2008 and, as such, only five months of operations are included in the year ended December 31, 2008. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Dos Hermanos acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 2,724 Mcf/day of natural gas and 6,151 Gal/day of natural gas liquids during 2008.

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

The decrease in natural gas, natural gas liquids and oil sales during the year ended December 31, 2009 compared to the same period in 2008 was due primarily to the decreases in commodity prices. We experienced a 53% decrease in the average realized natural gas sales price received (excluding hedges) and a 37% decrease in the average realized oil price (excluding hedges). The decrease in commodity prices was partially offset by a 23% increase in our total production on a Mcfe basis. The increase in production for the year ended December 31, 2009 over the comparable period in 2008, despite not drilling any new wells in 2009, was primarily attributable to the impact from the Dos Hermanos, Sun TSH and Ward County acquisitions completed in July 2008, August 2009 and December 2009, respectively. In Appalachia, we experienced a 13% decrease in natural gas production which was partially offset by a 91% increase in oil production during year ended December 31, 2009 compared to the same period in 2008 for a net production decline of 5% on a Mcfe basis. The decrease in natural gas production is largely attributable to our decision to not drill wells in 2009 due to low natural gas prices. The 91% increase in Appalachian oil production was primarily due to our focus on completing to oil zones as oil prices increased during 2008 and recompleting to oil zones on existing natural gas wells in 2009, which also adversely affected the amount of natural gas produced in 2009.

Hedging and Price Risk Management Activities

During the year ended December 31, 2009, the Company recognized $2.4 million in losses on commodity cash flow hedges. 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 and designated as cash flow hedges. The loss on commodity cash flow hedges for the year ended December 31, 2009 relates to the amount that settled in 2009 and has been reclassified to earnings from accumulated other comprehensive loss. During the year ended December 31, 2009, the Company recognized a $30.0 million realized gain on other commodity derivative contracts related to the settlements recognized during the period and a $19.0 million loss related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting.

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

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses in Appalachia also historically included a $60 per well per month administrative charge pursuant to a management services agreement with Vinland. This fee was increased to $95 per well per month beginning March 1, 2009 through December 31, 2009 pursuant to an agreement whereunder Vinland has agreed to provide well-tending services on Vanguard owned wells under a turnkey pricing contract. In addition, we historically have paid a $0.25 per Mcf and $0.55 per Mcf gathering and compression charge for production from wells drilled pre and post January 1, 2007, respectively, to Vinland pursuant to a gathering and compression agreement with Vinland. This gathering and compression agreement was amended for the period beginning March 1, 2009 through December 31, 2009 to provide for a fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per Mcf margin. Lease operating expenses increased by $1.5 million to $12.7 million for the year ended December 31, 2009 as compared to the year ended December 31, 2008 of which $1.4 million related to the Dos Hermanos, Sun TSH and Ward County acquisitions.

Depreciation, depletion, amortization and accretion decreased to approximately $14.6 million for the year ended December 31, 2009 from approximately $14.9 million for the year ended December 31, 2008 due primarily to a lower unamortized cost of natural gas and oil properties as a result of the impairments of these properties recorded during the fourth quarter of 2008 and first quarter of 2009, offset by additional depletion recorded on natural gas and oil properties acquired in the Sun TSH and Ward County acquisitions.

An impairment of natural gas and oil properties in the amount of $110.2 million was recognized during the year ended December 31, 2009 as the unamortized cost of natural gas and oil properties exceeded the sum of the estimated future net revenues from proved properties using the 12-month average price of natural gas and oil, discounted at 10% and the lower of cost or fair value of unproved properties. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. The majority of the fourth quarter impairment was incurred on properties that we acquired in the last six months of 2009 when natural gas and oil prices were higher than the 12-month average price. We were able to lock in the higher prices at the time of the acquisitions for a substantial portion of the expected production through 2011 for natural gas and 2013 for crude oil by using commodity derivative contracts. However, the impairment calculation did not consider the positive impact of our commodity derivative positions as generally accepted accounting principles only allow 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, 2009 increased $3.9 million as compared to the year ended December 31, 2008. For the years ended December 31, 2009 and 2008 these expenses included non-cash charges of $2.5 million and $3.6 million, respectively, related to the grant of restricted Class B units to officers and an employee and the grant of common units to board members during 2007, 2008 and 2009. Additionally, during the year ended December 31, 2009, these expenses included a charge for the fair value of phantom units granted to officers of $4.3 million. These phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2009 and the amount paid in either cash or units will equal the appreciation in value of the units, if any, from the date of the grant until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. There was no appreciation in the fair value of phantom units granted to officers during the year ended December 31, 2008. The remaining increase of $0.7 million during the year ended December 31, 2009 as compared to the same period in 2008 is principally due to incremental costs associated with the company's growth and acquisitions.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes decreased by $1.1 million for the year ended December 31, 2009 as compared to the same period in 2008. Severance taxes decreased $1.2 million resulting from decreased natural gas, natural gas liquids and oil sales, Texas margin tax decreased by $0.5 million and ad valorem taxes increased by $0.6 million primarily due to the taxes in Appalachia being based on 2008 revenues.

Interest expense declined to $4.3 million for the year ended December 31, 2009 compared to $5.5 million for the year ended December 31, 2008 primarily due to lower interest rates and lower average outstanding debt for the year ended December 31, 2009.

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

Revenues

Natural gas, natural gas liquids 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,		Percentage Increase (Decrease)
	2008	2007	
Net Natural Gas Production:			
Appalachian gas (MMcf)	3,578	4,044	(12)%
Permian gas (MMcf)	185 (1)	—	N/A
South Texas gas (MMcf)	428 (2)	—	N/A
Total natural gas production (MMcf)	4,191	4,044	4%
Average Appalachian daily gas production (Mcf/day)	9,777	11,080	(12)%
Average Permian daily gas production (Mcf/day)	505 (1)	—	N/A
Average South Texas daily gas production (Mcf/day)	1,168 (2)	—	N/A
Average Vanguard daily gas production (Mcf/day)	11,450	11,080	3%
Average Natural Gas Sales Price per Mcf:			
Net realized gas price, including hedges	$10.49 (3)	$8.92 (3)	18%
Net realized gas price, excluding hedges	$10.38	$8.04	29%
Net Oil Production:			
Appalachian oil (Bbls)	48,977	30,629	60%
Permian oil (Bbls)	212,599 (1)	—	N/A
Total oil (Bbls)	261,576	30,629	754%
Average Appalachian daily oil production (Bbls/day)	134	84	60%
Average Permian daily oil production (Bbls/day)	581 (1)	—	N/A

Average Vanguard daily oil production (Bbls/day)	715	84	751%
Average Oil Sales Price per Bbl:			
Net realized oil price, including hedges	$85.69 (3)	$66.08 (3)	30%
Net realized oil price, excluding hedges	$91.48	$66.08	38%
Net Natural Gas Liquids Production:			
Permian natural gas liquids (Gal)	231,280 (1)	—	N/A
South Texas natural gas liquids (Gal)	965,718 (2)	—	N/A
Total natural gas liquids production (Gal)	1,196,998	—	N/A
Average Permian daily natural gas liquids production (Gal/day)	632 (1)	—	N/A
Average South Texas daily natural gas liquids production (Gal/day)	2,639 (2)	—	N/A
Average Vanguard daily natural gas liquids production (Gal/day)	3,271	—	N/A
Average Natural Gas Liquids Sales Price per Gal:			
Net realized natural gas liquids price	$1.18	—	N/A

(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 operations of 2007. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Permian Basin acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 552 Mcf/day of natural gas, 635 Bbls/day of oil and 690 Gal/day of natural gas liquids during 2008.

(2) The Dos Hermanos 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. The average daily production above is calculated based on the total number of days in the reported period regardless of how many days an acquisition contributed production in the reported period. The average daily production for the Dos Hermanos acquisition, based on the actual number of days from the acquisition closing date to the end of the reported period, was 2,724 Mcf/day of natural gas and 6,151 Gal/day of natural gas liquids during 2008.

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

The increase in natural gas, natural gas liquids and oil sales was due primarily to the impact of the Permian Basin acquisition completed on January 31, 2008, the Dos Hermanos acquisition completed on July 28, 2008 and increases in commodity prices during the first three quarters of 2008. Production from the Permian Basin and Dos Hermanos acquisitions contributed $25.8 million of natural gas, natural gas liquids 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 29% 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 in gains on commodity cash flow hedges. 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 and designated as cash flow hedges. 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 ASC Topic 815 and it discontinued hedge accounting effective January 1, 2008. The gain on commodity cash flow hedges for the year ended December 31, 2008 relates to the amount that settled in 2008 and has been reclassified to earnings from accumulated other comprehensive loss. During the year ended December 31, 2008, the Company recognized a$6.6 million realized loss on other commodity derivative contracts related to the settlements recognized during the period and a $39.0 million gain related to the change in fair value of derivative contracts not meeting the criteria for cash flow hedge accounting.

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

Costs and Expenses

Lease operating expenses include third-party transportation costs, gathering and compression fees, field personnel, and other customary charges. Lease operating expenses in Appalachia also included 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 Dos Hermanos acquisitions.

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 Dos Hermanos 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 GAAP 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.

Production and other taxes include severance, ad valorem, and other taxes. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. Production and other taxes increased by $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 Dos Hermanos acquisitions, and the remaining increase is attributable to higher severance taxes resulting from increased revenues in Appalachia.

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.

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 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 ASC Topic 360, "Property, Plant and Equipment," 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 based upon the 12-month average price (ceiling limitation). If the full-cost pool is in excess of the ceiling limitation, the excess amount is charged as an expense.

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, natural gas liquids and oil reserves, including salaries, benefits and other internal costs directly related to these finding activities. For the years ended December 31, 2009 and 2008, there were no internal costs capitalized. 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 natural gas and oil price based upon the 12-month average price, 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"). In 2009 and 2008, our hedges were not considered cash flow hedges for accounting purposes and thus the value of our hedges were not considered in our ceiling test calculation. Prior to the effective date, December 31, 2009, of the SEC's Final Rule, "Modernization of Oil and Gas Reporting," present value of future net revenue from proved properties was calculated based on period end natural gas and oil prices. The Final Rule requires that prices be based upon the 12-month average price rather than a year-end price to calculate the present value.

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, natural gas liquids and oil Reserve Quantities" below. Due to the imprecision in estimating natural gas, natural gas liquids and oil reserves as well as the potential volatility in natural gas, natural gas liquids and oil prices and their effect on the carrying value of our proved natural gas, natural gas liquids 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, natural gas liquids and oil prices, downward revisions in estimated proved natural gas, natural gas liquids 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, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. 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.

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, Natural Gas Liquids and Oil Reserve Quantities

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

In addition, the SEC has not reviewed our or any reporting company's reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules. Accordingly, while the estimates of our proved reserves at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Revenue Recognition

Sales of natural gas, natural gas liquids and oil are recognized when natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquids and oil fluctuates to remain competitive with other available natural gas, natural gas liquids and oil supplies. As a result, our revenues from the sale of natural gas, natural gas liquids and oil 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, natural gas liquids and oil contracts are customary in the industry.

The Company has elected the entitlements method to account for gas production imbalances. 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, 2009 or 2008.

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 and collars. The derivative instruments we established in 2007 were designated as hedges under ASC Topic 815. 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 ASC Topic 815. 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 ASC Topic 815, 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 ASC Topic 815. 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 ASC Topic 718 "Compensation-Stock Compensation" ("ASC Topic 718"). ASC Topic 718 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. 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 ASC Topic 718 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 vested two years from the date of grant. In addition, another 55,000 restricted VNR Class B units were issued in August 2007 to two other employees that were hired in April and May of 2007, which will vest after three years. The remaining 40,000 restricted Class B units were not granted and are not expected to be granted in the future. In October 2007 and February 2008, four board members were granted 5,000 common units each of which vested after one year. Additionally, in October 2007, two officers were granted options to purchase an aggregate of 175,000 units under our long-term incentive plan with an exercise price equal to the initial public offering price of $19.00 which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718, by calculating the Black-Scholes value of each option, using a volatility rate of 12.18%, an expected dividend yield of 8.95% and a discount rate of 5.12%, and multiplying the Black-Scholes value by the number of options awarded. In determining a volatility rate of 12.18%, the Company, due to a lack of historical data regarding the Company's common units, used the historical volatility of the Citigroup MLP Index over the 365 day period prior to the date of grant.

Furthermore, on January 1, 2009 and March 27, 2008, in accordance with their previously negotiated employment agreements, phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2009 and 2008. The 2008 phantom units expired on December 31, 2008 and no liability or expense was recognized as there was no appreciation in the value of the units. The amount in connection with the 2009 phantom units was paid in cash and in units at the election of the officers and is equal to the appreciation in value of the units from the date of the grant (January 1, 2009) until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. At December 31, 2009, an accrued liability and unit-based compensation expense of $4.3 million has been recognized in selling, general and administrative line item in the consolidated statement of operations, of which $0.4 million is non-cash compensation expense.

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

In February 2010, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the "Amended Agreements") with Scott W, Smith, our President and Chief Executive Officer, and Richard A. Robert, our Executive Vice President and Chief Financial Officer. The Amended Agreements provide for each executive to receive 15,000 restricted units granted pursuant to the Vanguard Natural Resources, LLC Long-Term Incentive Plan (the "LTIP"), as well as an annual grant of 15,000 phantom units granted pursuant to the LTIP. The restricted units are subject to a vesting period of three years. One-third of the aggregate number of the units will vest on each one-year anniversary of the date of grant so long as the executive remains continuously employed with the Company. The phantom units are also subject to a three year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three year anniversary of the date of grant so long as the executive remains continuously employed with the Company during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any dividends made by the Company on its units generally with respect to the number of phantom shares that executive received pursuant to this grant.

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 ASC Topic 718. With respect to the restricted Class B units granted to employees and the common units granted to directors and employees, we expect to incur $0.7 million in non-cash compensation expense for the year 2010. For the years ended December 31, 2009, 2008 and 2007, we recorded $2.5 million, $3.6 million and $2.1 million of non-cash compensation expense, respectively.

Recently Adopted Accounting Pronouncements

Effective July 1, 2009, the FASB's ASC became the single official source of authoritative, nongovernmental GAAP in the United States. The historical GAAP hierarchy was eliminated, and the ASC became the only level of authoritative GAAP, other than guidance issued by the SEC. Our accounting policies were not affected by the conversion to ASC. However, references to specific accounting standards in the footnotes to our consolidated financial statements have been changed to refer to the appropriate section of ASC.

In September 2006, the FASB issued guidance which defines fair value, establishes the framework for measuring fair value and expands disclosures about fair value measurements. This guidance is contained in ASC Topic 820, "Fair Value Measurements and Disclosures" ("ASC Topic 820"). In February 2008, the FASB deferred the effective date applicable to us to January 1, 2009 for all nonfinancial assets and liabilities, except for those that are recognized or disclosed at fair value on a recurring basis (that is, at least annually). On January 1, 2008, we adopted the provisions of ASC Topic 820, as it relates to financial assets and financial liabilities and we determined that the impact of the additional assumptions on fair value measurements did not have a material effect on our financial position or results of operations. We adopted the deferred provisions of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, and the adoption did not have a material impact on our financial position or results of operations. See Note 6 on Part II—Item 8—Notes to Consolidated Financial Statements for further discussion.

In April 2009, the FASB issued additional guidance for estimating fair value in accordance with ASC Topic 820. The additional guidance addresses determining fair value when the volume and level of activity for an asset or liability have significantly decreased and identifying transactions that are not orderly. We adopted the provisions of this guidance on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued guidance which established 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 in the business combination. This guidance is contained in ASC Topic 805, "Business Combinations" ("ASC Topic 805"). This guidance also established disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. Effective January 1, 2009, we adopted the provisions of ASC Topic 805 and applied the provisions to our acquisitions completed in the third and fourth quarters of 2009. See Note 2 on Part II—Item 8—Notes to Consolidated Financial Statements for further discussion.

In April 2009, the FASB issued additional guidance which amended the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination under ASC Topic 805. The requirements of ASC Topic 805 were carried forward for acquired contingencies, which would require that such contingencies be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with ASC Topic 450, "Contingencies." The adoption of the provisions in this additional guidance did not affect our consolidated financial statements.

In March 2008, the FASB issued guidance 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. This guidance is contained in ASC Topic 815, "Derivatives and Hedging" ("ASC Topic 815"). The guidance 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. Effective January 1, 2009, we adopted the provisions of ASC Topic 815, and the adoption did not have a material impact on our consolidated financial statements. See Note 5 on Part II—Item 8—Notes to Consolidated Financial Statements for further discussion.

In April 2009, the FASB issued guidance which amends disclosures about fair values of financial instruments and interim financial reporting to require disclosures about fair value of financial instruments in interim financial statements. This guidance is contained in ASC Topic 825, "Financial Instruments" ("ASC Topic 825"). We adopted the provisions of ASC Topic 825 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In May 2009, the FASB issued general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This guidance is contained in ASC Topic 855, "Subsequent Events" ("ASC Topic 855"). In particular, this guidance sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. In accordance with this guidance, an entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. We adopted the provisions of ASC Topic 855 effective June 30, 2009. In February 2010, the FASB issued Accounting Standards Update No. 2010-09 ("ASC Update 2010-09"), an update to ASC Topic 855. Among other provisions, this update provides that an entity that is an SEC filer is not required to disclose the date through which subsequent events have been evaluated. We adopted the provisions of ASC Update 2010-09 on its effective date, February 24, 2010. The adoption of the provisions of ASC Topic 855 and ASC Update 2010-09 did not have a material impact on our consolidated financial statements. See Note 13 on Part II—Item 8—Notes to Consolidated Financial Statements for discussion of subsequent events.

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 allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor, (2) file reports when a third party is relied upon to prepare reserves estimates or to conduct a reserves audit, and (3) report oil and gas reserves using the 12-month unweighted average of first-day-of-the-month price (the "12-month average price") rather than the year-end price. The use of average prices as of December 31, 2009 affected our fourth quarter 2009 depletion and impairment calculations and will affect future calculations. In January 2010, the FASB issued Accounting Standards Update 2010-03, "Extractive Activities-Oil and Gas (Topic 932) Oil and Gas Reserve Estimation and Disclosures" ("ASC Update 2010-3"), in order to align the oil and gas reserve estimation and disclosures requirements of "Extractive Activities-Oil and Gas (Topic 932)" with the requirements in the SEC's Final Rule. The main provisions of Update 2010-03, (1) expand the definition of oil-and gas-producing activities to include the extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction; (2) amend the definition of proved oil and gas reserves to indicate that entities must use the 12-month average price covered by the report rather than the year-end price when estimating whether reserve quantities are economical to produce and when calculating the aggregate amount and change in future cash inflows related to the standardize measure of discounted cash flows; (3) require that an entity disclose separately information about reserve quantities and financial statement amounts for geographic areas that represent 15 percent or more of proved reserves; and (4) expand the disclosure requirements for equity method investments. We adopted the Final Rule and the amendments to Topic 932 on December 31, 2009 and the adoption increased our fourth quarter 2009 depletion expense by $0.4 million and our impairment by $46.4 million. The adoption also resulted in a downward adjustment of 10.6 Bcfe to our total proved reserves and a downward adjustment of $152.2 million to the standardized measure of discounted future net cash flows as of December 31, 2009.

In August 2009, the FASB issued Accounting Standards Update No. 2009-05 ("ASC Update 2009-05"), an update to ASC Topic 820. This update provides amendments to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. Among other provisions, this update provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the valuation techniques described in ASC Update 2009-05. We adopted the provisions of ASC Update 2009-05 on its effective date, December 31, 2009 and the adoption did not have a material impact on our consolidated financial statements.

New Pronouncements Issued But Not Yet Adopted

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

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2009 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.

Capital Resources and Liquidity

Disruption to Functioning of Capital Markets

Multiple events during 2008 and 2009 involving numerous financial institutions effectively restricted liquidity within the capital markets throughout the United States and around the world. While capital markets remain volatile, efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector have improved the situation. As evidenced by our recent successful equity offerings, successful amendment of our reserve-based credit facility and recent successful equity and debt offerings by our peers, we believe that our access to capital has improved and we have been successful in improving our financial position to date.

During 2009, our unit price increased from a closing low of $6.35 on January 2, 2009 to a closing high of $22.07 on December 31, 2009. Also during 2009, we did not drill any wells on our operated properties and there was limited drilling on non-operated properties. We intend to move forward with our development drilling program when market conditions allow for an adequate return on the drilling investment and only when we have sufficient liquidity to do so. Maintaining adequate liquidity may involve the issuance of debt and equity at less attractive terms, could involve the sale of non-core assets and could require reductions in our capital spending. In the near-term we will focus on maximizing returns on existing assets by managing our costs, selectively deploying capital to improve existing production and drilling a limited number of wells which we believe will provide an adequate return on the investment.

Overview

We have utilized private equity, proceeds from bank borrowings, cash flow from operations and more recently the public equity markets for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of natural gas and oil properties; however, we expect to distribute to unitholders a significant portion of our free cash flow. As we execute our business strategy, we will continually monitor the capital resources available to us to meet future financial obligations, planned capital expenditures, acquisition capital and distributions to our unitholders. Our future success in growing reserves, production and cash flow will be highly dependent on the capital resources available to us and our success in drilling for and acquiring additional reserves. We expect to fund our drilling capital expenditures and distributions to unitholders with cash flow from operations, while funding any acquisition capital expenditures that we might incur with borrowings under our reserve-based credit facility and publicly offered equity, depending on market conditions. As of March 5, 2010, we have $58.3 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future natural gas, natural gas liquids and oil prices) from our proved natural gas, natural gas liquids and oil reserves. In December 2009, our borrowing base was increased from $170.0 million to

$195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. If commodity prices decline and banks continue to lower their internal projections of natural gas, natural gas liquids and oil prices, it is possible that we will be subject to a decrease in our borrowing base availability in the future. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold. As a result, absent accretive acquisitions, to the extent available after unitholder distributions, debt service, and capital expenditures, it is our current intention to utilize our excess cash flow during 2010 to reduce our borrowings under our reserve-based credit facility. Based upon current expectations, we believe existing liquidity and capital resources will be sufficient for the conduct of our business and operations for the foreseeable future.

Cash Flow from Operations

Net cash provided by operating activities was $52.2 million during the year ended December 31, 2009, compared to $39.6 million during the year ended December 31, 2008. The increase in cash provided by operating activities during the year ended December 31, 2009 as compared to the same period in 2008 was substantially generated from increased production volumes related to Dos Hermanos, Sun TSH and Ward County acquisitions which had been hedged at favorable prices generating significant realized gains on commodity derivative contracts. Changes in working capital increased total cash flows by $1.2 million in 2009 compared to decreasing total cash flows by $3.8 million in 2008. Contributing to the increase in the level of cash provided by operating activities during 2009 was a $4.7 million increase in accrued expenses that resulted primarily from the timing effects of payments for amounts related to the phantom units granted to officers. Offsetting this increase in cash flows from operating activities during 2009 was a $1.9 million increase in accounts receivable related to the timing of receipts from production from the acquisitions and a $1.2 million decrease in payable to affiliates related to the timing of payments. Both impairment charges and unrealized derivative gains and losses are accounted for as non-cash items and therefore did not impact our liquidity or cash flows provided by operating activities during the years ended December 31, 2009 or 2008.

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. The increase in cash provided by operating activities during the year ended December 31, 2008 as compared to the same period in 2007 was substantially generated from increased production revenue related to the Permian Basin and Dos Hermanos acquisitions and higher average realized prices during 2008. Changes in working capital decreased total cash flows by $3.8 million in 2008 compared to decreasing total cash flows by $18.0 million in 2007. Contributing to the increase in the level of cash provided by operating activities during 2008 was a $3.2 million increase in accounts payable and accrued expenses that resulted from the timing effects of payments for amounts related to the acquisitions. Offsetting this increase in cash flows from operating activities during 2008 was a $2.2 million increase in accounts receivable also related to the timing of receipts from production from the acquisitions. Additionally, cash used in price risk management activities decreased during the year ended December 31, 2008 as premiums paid on derivative contracts during 2008 was $0.4 million compared to price risk management activities in 2007, which included the termination of existing natural gas swaps at a cost of approximately $2.8 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. The cash used in operating activities during the year ended December 31, 2007 also included the cash paid on early extinguishment of debt of approximately $2.5 million.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas, natural gas liquids and oil prices. Natural gas, natural gas liquids and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic 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, natural gas liquids 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 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 2013.

Investing Activities—Acquisitions and Capital Expenditures

Cash used in investing activities was $109.3 million for the year ended December 31, 2009, and $119.5 million and $26.4 million for the years ended December 31, 2008 and 2007, respectively. The decrease 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 Dos Hermanos during the year ended December 31, 2008 compared to $103.9 million used for the Sun TSH and Ward acquisitions during the year ended December 31, 2009. In addition, the total for the year ended

December 31, 2008 includes $ 18.2 million for drilling and development of natural gas and oil properties as compared to $5.0 million for the year ended December 31, 2009 as a result of our decision to not drill wells in 2009 due to low natural gas prices. The total for 2007 includes $3.6 million for acquisitions of natural gas and oil properties, $12.8 million for drilling and development of natural gas and oil properties and $9.8 million for deposits on acquisition of and prepayments of natural gas and oil properties.

Excluding any potential acquisitions, we currently anticipate a capital budget for 2010 of between $12.5 million and $13.5 million, which predominantly consists of recompletions and workovers of existing wells and a limited amount of new drilling in South Texas and the Permian Basin. This capital budget is expected to be funded through cash from operations. As of March 5, 2010, we had $58.3 million available for borrowing under our reserve-based credit facility. Our current borrowing base is $195.0 million. Our next borrowing base redetermination is scheduled for April 2010 utilizing our December 31, 2009 reserve report. If commodity prices decline and banks continue to lower their internal projections of natural gas, natural gas liquids and oil prices, it is possible that we will be subject to decreases in our borrowing base availability in the future. 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, 2010. 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 $57.6 million for year ended December 31, 2009, compared to $76.9 million for the year ended December 31, 2008. During the year ended December 31, 2009, total net repayments under our reserve-based credit facility were $5.2 million. Additionally, $27.1 million was used for distributions to unitholders and $3.1 million was paid for financing costs, compared to $20.1 million used for distribution to unitholders and $0.3 million paid for financing costs in the comparable period in 2008. Proceeds from the equity offerings of 6.5 million common units completed in August 2009 and December 2009 provided financing cash flows totaling $97.6 million, net of offering costs of $0.6 million, during the year ended December 31, 2009. Furthermore, $4.3 million was used to redeem common units held by our largest unitholder.

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 Dos Hermanos 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 our initial public offering which contributed $89.9 million in financing cash flows. We also completed a private equity offering for $41.2 million and used the net proceeds of this private equity offering to make a distribution to VNR’s sole member at that time.

Reserve-Based Credit Facility

On January 3, 2007, we entered into a reserve-based credit facility under which our initial borrowing base was set at $115.5 million. Our reserve-based credit facility was amended and restated in February 2008 to extend the maturity date from January 2011 to March 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and the Bank of Nova Scotia. The increase in the borrowing base was principally the result of inclusion of the reserves related to the Permian Basin acquisition in January 2008. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. As of October 22, 2008, our reserve-based credit facility was amended and restated to increase the borrowing base to $175.0 million and add one lender, BBVA Compass Bank. The increase in the borrowing base was principally the result of inclusion of the reserves related to the Dos Hermanos acquisition in July 2008. In February 2009, a third amendment was entered into which amended covenants to allow us to repurchase up to $5.0 million of our own units. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. At December 31, 2009, we had $129.8 million outstanding under our reserve-based credit facility and as of March 5, 2010, we have $58.3 million available to be borrowed under our reserve-based credit facility.

The borrowing base is subject to adjustment from time to time but not less than on a semi-annual basis based on the projected discounted present value of estimated future net cash flows (as determined by the bank's petroleum engineers utilizing the bank's internal projection of future natural gas, natural gas liquids and oil prices) from our proved natural gas, natural gas liquids and oil reserves. In December 2009, our borrowing base was set at $195.0 million. Our next borrowing base redetermination is scheduled for April 2010 utilizing our December 31, 2009 reserve report. If commodity prices decline and banks continue to lower their internal projections of natural gas, natural gas liquids and oil prices, it is possible that we will be subject to decreases in our borrowing base availability in the future. If our outstanding borrowings under the reserve-based credit facility exceed 90% of the borrowing base, we would be required to suspend distributions to our unitholders until we have reduced our borrowings to below the 90% threshold. As a result, absent accretive acquisitions, it is our current intention to utilize our excess cash flow during 2010 to reduce our borrowings under our reserve-based credit facility.

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

At our election, interest is determined by reference to:

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

As of December 31, 2009, we have elected for interest to be determined by reference to the LIBOR method described above. Interest is generally payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans, but not less frequently than quarterly.

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

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

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

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

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

We believe that we are in compliance with the terms of our reserve-based credit facility. If an event of default exists under the reserve-based credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. 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, 2009, there were no material loss contingencies.

Commitments and Contractual Obligations

A summary of our contractual obligations as of December 31, 2009 is provided in the following table.

	Payments Due by Year (in thousands)						
	2010	2011	2012	2013	2014	After 2014	Total
Management base salaries	$ 683	$ 570	$ 570	$ —	$ —	$ —	$ 1,823

(1)							
Asset retirement obligations	—	307	73	95	117	3,828	4,420
Derivative liabilities	6,399	7,945	882	401	—	—	15,627
Long-term debt (2)	—	—	129,800	—	—	—	129,800
Operating leases (3)	117	122	130	33	—	—	402
Total	$ 7,199	$ 8,944	$ 131,455	529	$ 117	$ 3,828	$ 152,072

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(1) Includes annual base salaries under second amended and restated executive employment agreements entered into in February 2010.

(2) 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.

(3) Includes lease agreement entered into in February 2010 which expires in February 2013.

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, natural gas liquids and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. Conditions sometimes arise where actual production is less than estimated, which has, and could result in overhedged volumes.

Commodity Price Risk

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

Furthermore, the risk that we will be required to write down the carrying value of our natural gas and oil properties increases when oil and gas prices are low or volatile. In addition, write downs may occur if we experience substantial downward adjustments to our estimated proved reserves, or if estimated future development costs increase. For example, natural gas, natural gas liquids and oil prices were very volatile throughout 2009. We recorded a non-cash ceiling test impairment of natural gas and oil properties for the year ended December 31, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC's Final Rule, "Modernization of Oil and Gas Reporting," which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. Additionally, if natural gas prices decline by $1.00 per MMBtu and oil prices declined by $6.00 per barrel, the standardized measure of our proved reserves as of December 31, 2009 would decrease from $178.7 million to $115.8 million, based on price sensitivity generated from an internal evaluation. This sensitivity analysis is calculated using a natural gas price of $2.87 per MMBTU ($3.87 year-end price less $1.00 (or 26%)) and an oil price of $55.04 per barrel of crude oil ($61.04 year-end price less $6.00 (or 10%)).

We enter into derivative contracts with respect to a portion of our projected natural gas and oil production through various transactions that mitigate the volatility of future prices received. These transactions may include price swaps whereby we will receive a fixed-price for our production and pay a variable market price to the contract counterparty. Additionally, we may acquire put options for which we pay the counterparty an option premium, equal to the fair value of the option at the purchase date. As each monthly contract settles, we receive the excess, if any, of the fixed floor over the floating rate. Furthermore, we may enter into collars where we pay the counterparty if the market price is above the ceiling price and the counterparty pays us if the market price is below the floor on a notional quantity. In deciding which type of derivative instrument to use, our management considers the relative benefit of each type against any cost that would be incurred, prevailing commodity market conditions and management’s view on future commodity pricing. The amount of natural gas and oil production which is hedged is determined by applying a percentage to the expected amount of production in our most current reserve report in a given year. Typically, management intends to hedge 75% to 95% of projected production for a three year period. These activities are intended to support our realized commodity prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. It is never management’s intention to hold or issue derivative instruments for speculative trading purposes. Management will consider liquidating a derivative contract if they believe that they can take advantage of an unusual market condition allowing them to realize a current gain and then have the ability to enter into a new derivative contract in the future at or above the commodity price of the contract that was liquidated.

At December 31, 2009, the fair value of commodity derivative contracts was an asset of approximately $21.3 million, of which $16.2 million settle during the next twelve months. A 10% increase in the gas and oil index price above the December 31, 2009 price would result in a decrease in the fair value of all of our commodity derivative contracts of approximately $14.5 million; conversely, a 10% decrease in the gas and oil index price would result in an increase of approximately $14.5 million. This sensitivity analysis measures the current value of the Company's commodity derivative contracts using forward price curves and volatility surfaces under a proprietary system and then increases or decreases, as applicable, the forward price curve to determine the fair value of the commodity derivative contracts under the assumed natural gas and oil price indexes.

The following table summarizes commodity derivative contracts in place at December 31, 2009:

	2010	2011	2012	2013
Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	4,731,040	3,328,312	—	—
Fixed Price ($/MMBtu)	$ 8.66	$ 7.83	$ —	$ —
Collars:				
Notional Volume (MMBtu)	1,607,500	1,933,500	—	—
Floor Price ($/MMBtu)	$ 7.73	$ 7.34	$ —	$ —
Ceiling Price ($/MMBtu)	$ 8.92	$ 8.44	$ —	$ —
Total:				
Notional Volume (MMBtu)	6,338,540	5,261,812	—	—
Oil Positions:				
Fixed Price Swaps:				
Notional Volume (Bbls)	310,250	260,750	137,250	118,625
Fixed Price ($/Bbl)	$ 85.93	$ 86.12	$ 88.13	$ 88.42
Collars:				
Notional Volume (Bbls)	—	—	45,750	45,625
Floor Price ($/Bbl)	$ —	$ —	$ 80.00	$ 80.00
Ceiling Price ($/Bbl)	$ —	$ —	$ 100.25	$ 100.25
Total:				
Notional Volume (Bbls)	310,250	260,750	183,000	164,250

Interest Rate Risks

At December 31, 2009, we had debt outstanding of $129.8 million, which incurred interest at floating rates based on LIBOR in accordance with our reserve-based credit facility and if the debt remains the same, a 1% increase in LIBOR would result in an estimated $0.3 million increase in annual interest expense after consideration of the interest rate swaps discussed below.

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

The following summarizes information concerning our positions in open interest rate swaps at December 31, 2009.

Period:	Notional Amount	Fixed Libor Rates
January 1, 2010 to December 18, 2010	$ 10,000,000	1.50%
January 1, 2010 to December 20, 2010	$ 10,000,000	1.85%
January 1, 2010 to January 31, 2011	$ 20,000,000	3.00% (1)
January 1, 2010 to March 31, 2011	$ 20,000,000	2.08%
January 1, 2010 to December 10, 2012	$ 20,000,000	3.35%
January 1, 2010 to January 31, 2013	$ 20,000,000	2.38%

(1) In February 2010, we extended the terms of the 3.00%, $20.0 million interest rate swap for two additional years to January 31, 2013 and reduced the rate from 3.00% to 2.66%.

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.

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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 sheets of Vanguard Natural Resources, LLC as of December 31, 2009 and 2008 and the related consolidated statements of operations, comprehensive loss, members' equity and cash flows for the years 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 audits.

We conducted our audits 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 audits provide 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, 2009 and 2008, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 1 and 2 to the consolidated financial statements, effective January 1, 2009, the Company adopted the provisions of Accounting Standards Codification Topic 805 "Business Combinations." As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new natural gas and oil reserve estimation and disclosure requirements.

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, 2009, 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 5, 2010 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Houston, Texas
March 5, 2010

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 statements of operations, members' equity, cash flows and comprehensive loss of Vanguard Natural Resources, LLC (a Delaware limited liability company) and subsidiaries (the "Company") for the year ended December 31, 2007. 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 results of operations and cash flows of Vanguard Natural Resources, LLC and subsidiaries for the year ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
March 31, 2008

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Operations
For the Years Ended December 31,
(in thousands, except per unit data)

	2009	2008	2007
Revenues			
Natural gas, natural gas liquids and oil sales	$ 46,035	$ 68,850	$ 34,541
Gain (loss) on commodity cash flow hedges	(2,380)	269	(702)
Realized gain (loss) on other commodity derivative contracts	29,993	(6,552)	—
Unrealized gain (loss) on other commodity derivative contracts	(19,043)	39,029	—
Total revenues	54,605	101,596	33,839
Costs and expenses			
Lease operating expenses	12,652	11,112	5,066
Depreciation, depletion, amortization and accretion	14,610	14,910	8,981
Impairment of natural gas and oil properties	110,154	58,887	—
Selling, general and administrative expenses	10,644	6,715	3,507
Bad debt expense	—	—	1,007
Production and other taxes	3,845	4,965	2,054
Total costs and expenses	151,905	96,589	20,615
Income (loss) from operations	(97,300)	5,007	13,224
Other income (expense)			
Interest income	—	17	62
Interest expense	(4,276)	(5,491)	(8,135)
Gain on acquisition of natural gas and oil properties	6,981	—	—
Realized loss on interest rate derivative contracts	(1,903)	(107)	—
Unrealized gain (loss) on interest rate derivative contracts	763	(3,178)	—
Loss on extinguishment of debt	—	—	(2,502)
Total other income (expense)	1,565	(8,759)	(10,575)
Net income (loss)	$ (95,735)	$ (3,752)	$ 2,649
Net income (loss) per Common and Class B units-basic & diluted	$ (6.74)	$ (0.32)	$ 0.39
Weighted average units outstanding:			
Common units – basic & diluted	13,791	11,374	6,533
Class B units – basic & diluted	420	420	279

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Balance Sheets
As of December 31,
(in thousands)

	2009	2008
Assets		
Current assets		
Cash and cash equivalents	$ 487	$ 3
Trade accounts receivable, net	8,025	6,083
Derivative assets	16,190	22,184
Other receivables	2,224	2,763
Other currents assets	1,317	845
Total current assets	28,243	31,878
Natural gas and oil properties, at cost	399,212	284,447
Accumulated depletion, amortization and accretion	(226,687)	(102,178)
Natural gas and oil properties evaluated, net – full cost method	172,525	182,269
Other assets		
Derivative assets	5,225	15,749
Deferred financing costs	3,298	882
Other assets	1,409	1,784
Total assets	$ 210,700	$ 232,562
Liabilities and members' equity		
Current liabilities		
Accounts payable – trade	$ 766	$ 2,148
Accounts payable – natural gas and oil	2,299	1,327
Payables to affiliates	1,387	2,555
Deferred swap premium liability	1,334	—
Derivative liabilities	253	486
Phantom unit compensation accrual	4,299	—
Accrued ad valorem taxes	903	34
Accrued expenses	1,178	1,214
Total current liabilities	12,419	7,764
Long-term debt	129,800	135,000
Derivative liabilities	2,036	2,313
Deferred swap premium liability	1,739	—
Asset retirement obligations	4,420	2,134
Total liabilities	150,414	147,211
Commitments and contingencies (Note 9)		
Members' equity		
Members' capital, 18,416,173 and 12,145,873 common units issued and outstanding at December 31, 2009 and 2008,	59,873	88,550

respectively				
Class B units, 420,000 issued and outstanding at December 31, 2009 and 2008		5,930		4,606
Accumulated other comprehensive loss		(5,517)		(7,805)
Total members' equity		60,286		85,351
Total liabilities and members' equity	$	210,700	$	232,562

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Consolidated Statements of Members' Equity
For the Years Ended December 31, 2009, 2008 and 2007
(in thousands, except per unit data)

	Common Units	Common Units Amount	Class B Units	Class B Units Amount	Accumulated Other Comprehensive Loss	Total Members' Equity
Balance, January 1, 2007	—	$ —	—	$ —	—	$ —
Initial contribution	5,540	3,288	—	—	—	3,288
Sale of private placement units	—	41,220	—	—	—	41,220
Distributions to member	—	(41,220)	—	—	—	(41,220)
Issuance of common units, net of offering costs of $9,804	5,250	89,947	—	—	—	89,947
Distributions to members	—	(5,626)	—	—	—	(5,626)
Unit-based compensation	5	—	420	2,132	—	2,132
Net income	—	2,649	—	—	—	2,649
Settlement of cash flow hedges in other comprehensive loss	—	—	—	—	(10,059)	(10,059)
Balance, December 31, 2007	10,795	$ 90,258	420	$ 2,132	$ (10,059)	$ 82,331
Distributions to members ($0.291, $0.445, $0.445 and $0.50 per unit to unitholders of record February 7, 2008, April 30, 2008, July 31, 2008 and October 31, 2008, respectively)	—	(19,423)	—	(706)	—	(20,129)
Issuance of common units for acquisition of natural gas and oil properties, net of offering costs of $54	1,351	21,306	—	—	—	21,306
Unit-based compensation	—	161	—	3,180	—	3,341
Net loss	—	(3,752)	—	—	—	(3,752)

Settlement of cash flow hedges in other comprehensive income	—	—	—	—	2,254	2,254

Balance at December 31, 2008	12,146	$88,550	420	$4,606	$(7,805)	$85,351
Distributions to members ($0.50 per unit to unitholders of record January 30, 2009, April 30, 2009, July 31, 2009 and November 6, 2009, respectively)	—	(26,258)	—	(840)	—	(27,098)
Issuance of common units, net of offering costs of $613	6,520	97,627	—	—	—	97,627
Redemption of common units	(250)	(4,305)	—	—	—	(4,305)
Unit-based compensation	—	(6)	—	2,164	—	2,158
Net loss	—	(95,735)	—	—	—	(95,735)
Settlement of cash flow hedges in other comprehensive income	—	—	—	—	2,288	2,288
Balance at December 31, 2009	18,416	$59,873	420	$5,930	$(5,517)	$60,286

See accompanying notes to consolidated financial statements.

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

	2009	2008	2007
Operating activities			
Net income (loss)	$ (95,735)	$ (3,752)	$ 2,649
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	14,610	14,910	8,981
Impairment of natural gas and oil properties	110,154	58,887	—
Amortization of deferred financing costs	639	362	296
Bad debt expense	—	—	1,007
Unit-based compensation	2,483	3,577	2,132
Non-cash portion of phantom units granted to officers	393	—	—
Amortization of premiums paid on derivative contracts	3,502	4,493	4,274
Amortization of value on derivative contracts acquired	3,619	733	—
Unrealized (gains) losses on other commodity and interest rate derivative contracts	18,280	(35,851)	—
Gain on acquisitions of natural gas and oil properties	(6,981)	—	—
Changes in operating assets and liabilities:			
Trade accounts receivable	(1,942)	(2,208)	(504)
Payables to affiliates	(1,168)	(1,850)	(531)
Price risk management activities, net	94	(343)	(15,798)
Other receivables	539	(2,265)	—
Other current assets	(536)	(345)	(340)
Accounts payable	(410)	2,161	1,244
Accrued expenses	4,739	1,045	(2,037)
Other assets	(125)	—	—
Net cash provided by operating activities	52,155	39,554	1,373
Investing activities			
Additions to property and equipment	(57)	(74)	(132)
Additions to natural gas and oil properties	(4,960)	(18,174)	(12,821)
Acquisitions of natural gas and oil properties	(103,923)	(100,743)	(3,650)
Deposits and prepayments of natural gas and oil properties	(375)	(548)	(9,806)
Net cash used in investing activities	(109,315)	(119,539)	(26,409)
Financing activities			
Proceeds from borrowings	80,349	340,300	126,200
Repayment of debt	(85,549)	(242,700)	(182,868)

Proceeds from equity offerings, net	97,627	(54)	89,947
Redemption of common units	(4,305)	—	—
Proceeds from private placement units	—	—	41,220
Distributions to members	(27,098)	(20,129)	(46,846)
Financing costs	(3,055)	(303)	(1,238)
Purchases of units for issuance as unit-based compensation	(325)	(236)	—
Net cash provided by financing activities	57,644	76,878	26,415
Net increase (decrease) in cash and cash equivalents	484	(3,107)	1,379
Cash and cash equivalents, beginning of year	3	3,110	1,731
Cash and cash equivalents, end of year	$ 487	$ 3	$ 3,110

Supplemental cash flow information:						
Cash paid for interest	$	3,894	$	5,040	$	8,839
Non-cash financing and investing activities:						
Asset retirement obligations	$	2,163	$	1,882	$	177
Derivatives assumed in acquisition of natural gas and oil properties	$	4,128	$	2,468	$	—
Deferred swap liability	$	3,072	$	—	$	—
Non-monetary exchange of natural gas and oil properties	$	2,660	$	—	$	—
Initial contribution of assets	$	—	$	—	$	3,288
Issuance of common units for acquisition of natural gas and oil properties	$	—	$	21,360	$	—
Transfer of deposit for acquisition of natural gas and oil properties	$	—	$	7,830	$	—

See accompanying notes to consolidated financial statements.

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

	2009	2008	2007
Net income (loss)	$ (95,735)	$ (3,752)	$ 2,649
Net income (losses) from derivative contracts:			
Unrealized mark-to-market gains (losses) arising during the period	—	2,747	(9,644)
Reclassification adjustments for settlements	2,288	(493)	(415)
Other comprehensive income (loss)	2,288	2,254	(10,059)
Comprehensive loss	$ (93,447)	$ (1,498)	$ (7,410)

See accompanying notes to consolidated financial statements.

Vanguard Natural Resources, LLC and Subsidiaries
Notes to Consolidated Financial Statements
December 31, 2009

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

We were formed in October 2006 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. We refer to these events as the “Restructuring.” Vinland operates all of our existing wells in Appalachia and all of the wells that we drilled in Appalachia.

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 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.

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, 2009, 2008 and 2007 include the accounts of VNR and its wholly-owned subsidiaries.

Our consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) 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 members’ equity.

(b) Recently Adopted Accounting Pronouncements:

Effective July 1, 2009, the Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") became the single official source of authoritative, nongovernmental GAAP in the United States. The historical GAAP hierarchy was eliminated, and the ASC became the only level of authoritative GAAP, other than guidance issued by the Securities and Exchange Commission ("SEC"). Our accounting policies were not affected by the conversion to ASC. However, references to specific accounting standards in the footnotes to our consolidated financial statements have been changed to refer to the appropriate section of ASC.

In September 2006, the FASB issued guidance which defines fair value, establishes the framework for measuring fair value and expands disclosures about fair value measurements. This guidance is contained in ASC Topic 820, "Fair Value Measurements and Disclosures" ("ASC Topic 820"). In February 2008, the FASB deferred the effective date applicable to us to January 1, 2009 for all nonfinancial assets and liabilities, except for those that are recognized or disclosed at fair value on a recurring basis (that is, at least annually). On January 1, 2008, we adopted the provisions of ASC Topic 820, as it relates to financial assets and financial liabilities and we determined that the impact of the additional assumptions on fair value measurements did not have a material effect on our financial position or results of operations. We adopted the deferred provisions of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, and the adoption did not have a material impact on our financial position or results of operations. See Note 6. Fair Value Measurements for further discussion.

In April 2009, the FASB issued additional guidance for estimating fair value in accordance with ASC Topic 820. The additional guidance addresses determining fair value when the volume and level of activity for an asset or liability have significantly decreased and identifying transactions that are not orderly. We adopted the provisions of this guidance on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued guidance which established 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 in a business combination. This guidance is contained in ASC Topic 805, “Business Combinations” (“ASC Topic 805”). This guidance also established disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. Effective January 1, 2009, we adopted the provisions of ASC Topic 805 and applied the provisions to our acquisitions completed in the third and fourth quarters of 2009. See Note 2. Acquisitions for further discussion.

In April 2009, the FASB issued additional guidance which amended the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination under ASC Topic 805. The requirements of ASC Topic 805 were carried forward for acquired contingencies, which would require that such contingencies be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with ASC Topic 450, “Contingencies.” The adoption of the provisions in this additional guidance did not affect our consolidated financial statements.

In March 2008, the FASB issued guidance 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. This guidance is contained in ASC Topic 815, “Derivatives and Hedging” (“ASC Topic 815”). The guidance 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. Effective January 1, 2009, we adopted the provisions of ASC Topic 815, and the adoption did not have a material impact on our consolidated financial statements. See Note 5. Price and Interest Rate Risk Management Activities for further discussion.

In April 2009, the FASB issued guidance which amends disclosures about fair values of financial instruments and interim financial reporting to require disclosures about fair value of financial instruments in interim financial statements. This guidance is contained in ASC Topic 825, “Financial Instruments” (“ASC Topic 825”). We adopted the provisions of ASC Topic 825 on June 30, 2009 and the adoption did not have a material impact on our consolidated financial statements.

In May 2009, the FASB issued general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This guidance is contained in ASC Topic 855, “Subsequent Events” (“ASC Topic 855”). In particular, this guidance sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. In accordance with this guidance, an entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. We adopted the provisions of ASC Topic 855 effective June 30, 2009. In February 2010, the FASB issued Accounting Standards Update No. 2010-09 (“ASC Update 2010-09”), an update to ASC Topic 855. Among other provisions, this update provides that an entity that is an SEC filer is not required to disclose the date through which subsequent events have been evaluated. We adopted the provisions of ASC Update 2010-09 on its effective date, February 24, 2010. The adoption of the provisions of ASC Topic 855 and ASC Update 2010-09 did not have a material impact on our consolidated financial statements. See Note 13. Subsequent Events for discussion of subsequent events.

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 allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (1) report the independence and qualifications of its reserves preparer or auditor, (2) file reports when a third party is relied upon to prepare reserves estimates or to conduct a reserves audit, and (3) report oil and gas reserves using the 12-month unweighted average of first-day-of-the-month price (the "12-month average price") rather than the year-end price. In January 2010, the FASB issued Accounting Standards Update 2010-03, "Extractive Activities-Oil and Gas (Topic 932) Oil and Gas Reserve Estimation and Disclosures" ("ASC Update 2010-3"), in order to align the oil and gas reserve estimation and disclosures requirements of "Extractive Activities-Oil and Gas (Topic 932)" with the requirements in the SEC's Final Rule. The main provisions of Update 2010-03, (1) expand the definition of oil-and gas-producing activities to include the extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction; (2) amend the definition of proved oil and gas reserves to indicate that entities must use the 12-month average price covered by the report rather than the year-end price when estimating whether reserve quantities are economical to produce and when calculating the aggregate amount and change in future cash inflows related to the standardize measure of discounted cash flows; (3) require that an entity disclose separately information about reserve quantities and financial statement amounts for geographic areas that represent 15 percent or more of proved reserves; and (4) expand the disclosure requirements for equity method investments. We adopted the Final Rule and the amendments to Topic 932 on December 31, 2009 and the adoption increased our fourth quarter 2009 depletion expense by $0.4 million and our impairment by $46.4 million. The adoption also resulted in adjustments to our total proved reserves and to the standardized measure of discounted future net cash flows as of December 31, 2009 presented in the accompanying unaudited supplemental natural gas and oil information.

In August 2009, the FASB issued Accounting Standards Update No. 2009-05 ("ASC Update 2009-05"), an update to ASC Topic 820. This update provides amendments to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. Among other provisions, this update provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the valuation techniques described in ASC Update 2009-05. We adopted the provisions of ASC Update 2009-05 on its effective date, December 31, 2009 and the adoption did not have a material impact on our consolidated financial statements.

(c) New Pronouncements Issued But Not Yet Adopted:

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

In January 2010, the FASB issued authoritative guidance intended to improve disclosures about fair value measurements. The guidance requires entities to disclose significant transfers in and out of fair value hierarchy levels and the reasons for the transfers and to present information about purchases, sales, issuances and settlements separately in the reconciliation of fair value measurements using significant unobservable inputs (Level 3). Additionally, the guidance clarifies that a reporting entity should provide fair value measurements for each class of assets and liabilities and disclose the inputs and valuation techniques used for fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3). This guidance is effective for interim and annual periods beginning after December 15, 2009 except for the disclosures about purchases, sales, issuances and settlements in the Level 3 reconciliation, which will be effective for interim and annual periods beginning after December 15, 2010. As this guidance provides only disclosure requirements, the adoption of this standard will not impact our results of operations, cash flows or financial position.

(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) 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, natural gas liquids 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 the 12-month average price, 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, 2009 of $110.2 million. The impairment for the first quarter 2009 was $63.8 million as a result of a decline in natural gas prices at the measurement date, March 31, 2009. This impairment was calculated based on prices of $3.65 per MMBtu for natural gas and $49.64 per barrel of crude oil. The SEC’s Final Rule, “Modernization of Oil and Gas Reporting,” which became effective December 31, 2009, changed the price used to calculate oil and gas reserves to a 12-month average price rather than a year-end price. As a result of declines in natural gas and oil prices based upon the 12-month average price, we recorded an impairment of $46.4 million in the fourth quarter of 2009. This impairment was calculated using the 12-month average price for natural gas and oil of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil. Additionally, 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.

When we sell or convey interests in natural gas and oil properties, we 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.

(h) 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 asset's 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.

(i) 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.

(j) Revenue Recognition and Gas Imbalances:

Sales of natural gas, natural gas liquids and oil are recognized when natural gas, natural gas liquids 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, natural gas liquids 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, natural gas liquid or oil, and prevailing supply and demand conditions, so that the price of the natural gas, natural gas liquid and oil fluctuates to remain competitive with other available natural gas, natural gas liquid and oil supplies.

The Company has elected the entitlements method to account for gas production imbalances. 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. The amounts of imbalances were not material at December 31, 2009 and 2008.

(k) 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, 2009 and 2008, the cash and cash equivalents were 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, natural gas liquids and oil sales for the years ended December 31:

	2009	2008	2007
Seminole Energy Services	35%	52%	—
North American Energy Corporation	—	—	41%
Osram Sylvania, Inc.	9%	15%	16%
BP Energy Company	—	10%	11%
Dominion Field Services, Inc.	—	—	13%
Eagle Energy Partners, LLC	—	—	11%

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.

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

(m) Price and Interest Rate Risk Management Activities:

We have entered into derivative contracts with counterparties that are lenders under our reserve-based credit facility, Citibank N.A., BNP Paribas, The Bank of Nova Scotia, BBVA Compass Bank and Wells Fargo Bank, N.A. (also under the name Wachovia Bank, N.A.), to hedge price risk associated with a portion of our natural gas and oil production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Under fixed-priced commodity swap agreements, 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 the 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. No payments are made if the market price is between the floor price and the ceiling price. Put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub and collars are settled based on a market index selected by us at inception of the contract. We also enter into fixed LIBOR interest rate swap agreements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Any premiums paid on derivative contracts and the fair value of derivative contracts acquired in connection with our acquisitions, are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid or the contracts are assumed. Over time, as the derivative contracts settle, the premiums paid or fair value of contracts acquired are amortized and recognized as a realized gain or loss on other commodity or interest rate derivate contracts and reflected as non-cash adjustments to net income or loss in our consolidated statement of cash flows.

Under ASC Topic 815 "Derivatives and Hedging," all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) in the equity section of the consolidated balance sheets to the extent the hedge is effective. Gains and losses on cash flow hedges included in accumulated other comprehensive income (loss) are reclassified to gains (losses) on commodity cash flow hedges or gains (losses) on interest rate derivative contracts in the period that the related production is delivered or the contract settles. The realized and unrealized gains (losses) on derivative contracts that do not qualify for hedge accounting treatment are recorded as gains (losses) on other commodity derivative contracts or gains (losses) on interest rate derivative contracts in the consolidated statements of operations.

(n) 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 $38.0 million and $54.7 million at December 31, 2009 and 2008, respectively.

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 during each of the years ended December 31, 2009 and 2008, respectively and a deferred tax asset of $0.1 million during the year ended December 31, 2009 and a deferred tax liability of $0.2 million during the year ended December 31, 2008. A benefit of $0.2 million and a charge of $0.3 million are included in our consolidated statements of operations for the years ended December 31, 2009 and 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. We refer to this acquisition 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 which included a purchase price adjustment of $6.8 million for the cash flow from the acquired properties for the period between the effective date, October 1, 2007, and the final settlement date. As part of this acquisition, we assumed fixed-price oil swaps covering approximately 90% of the estimated proved developed producing oil reserves through 2011 at a weighted average price of $87.29. The fair value of these fixed-price oil swaps was a liability of $1.1 million at January 31, 2008. This acquisition was funded with borrowings under our existing reserve-based credit facility.

On July 18, 2008, we entered into a Purchase and Sale Agreement with Segundo Navarro Drilling, Ltd. ("Segundo"), 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. We refer to this acquisition as the "Dos Hermanos 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. This acquisition was funded with $30.0 million of borrowings under our reserve-based credit facility and through the issuance of 1,350,873 common units of the Company valued at $21.4 million. Upon closing this transaction, we assumed natural gas swaps and collars based on Houston Ship Channel pricing for approximately 85% of the estimated gas production from existing producing wells in the acquired properties for the period beginning July 2008 through December 2011 which had a fair value of $3.6 million on July 28, 2008.

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

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Sun TSH acquisition as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $5.9 million, calculated in the following table. The gain resulted from the changes in natural gas and oil prices used to value the reserves and has been recognized in current period earnings and classified in other income and expense in the consolidated statements of operations.

	(in thousands)
Fair value of assets and liabilities acquired:	
Natural gas and oil properties	$ 54,942
Derivative assets	4,128
Other currents assets	187
Accrued expenses	(298)

Asset retirement obligations		(2,254)
Total fair value of assets and liabilities acquired		56,705
Fair value of consideration transferred		50,827
Gain on acquisition of natural gas and oil properties	$	5,878

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

In accordance with the guidance contained within ASC Topic 805, the measurement of the fair value at acquisition date of the assets acquired in the Ward County acquisitions as compared to the fair value of consideration transferred, adjusted for purchase price adjustments, resulted in a gain of $1.1 million, calculated in the following table. The gain resulted from the changes in natural gas and oil prices used to value the reserves and has been recognized in current period earnings and classified in other income and expense in the consolidated statement of operations.

	(in thousands)
Fair value of assets and liabilities acquired:	
Natural gas and oil properties	$ 56,347
Other currents assets	25
Asset retirement obligations	(248)
Total fair value of assets and liabilities acquired	56,124
Fair value of consideration transferred	55,021
Gain on acquisition of natural gas and oil properties	$ 1,103

The following unaudited pro forma results for the years ended December 31, 2009, 2008 and 2007 show the effect on our consolidated results of operations as if the Sun TSH and Ward County acquisitions had occurred on January 1, 2009 and 2008, and the Permian Basin and the Dos Hermanos acquisitions had occurred on January 1, 2008 and 2007. The pro forma results reflect the results of combining our statement of operations with the revenues and direct operating expenses of the oil and gas properties acquired adjusted for (1) assumption of asset retirement obligations and accretion expense for the properties acquired, (2) depletion expense applied to the adjusted basis of the properties acquired using the acquisition method of accounting, (3) interest expense on additional borrowings necessary to finance the acquisitions, (4) non-cash impairment charge, (5) the impact of common units issued to partially finance the Dos Hermanos acquisition, and (6) the impact of additional common units issued in connection with the 2009 equity offerings completed at the time of the Sun TSH and Ward County acquisitions. The pro forma information is based upon these assumptions, and is not necessarily indicative of future results of operations:

	Year Ended December 31,		
	2009 Pro forma	2008 Pro forma	2007 Pro forma
	(in thousands, except per unit amounts) (unaudited)		
Total revenues	$ 72,544	$ 151,956	$ 60,774
Net income (loss)	$ (82,715)	$ 36,218	$ 6,321
Net income (loss) per unit:			
Common & Class B units – basic & diluted	$ (4.39)	$ 1.92	$ 0.77

The amount of revenue and excess of revenues over direct operating expenses included in our consolidated statements of operations from the date of the closing through year end for each of our acquisitions are as follows:

	Year Ended December 31,	
	2009	2008
	(in thousands)	
Permian Basin		
Revenues	$ 14,372	$ 21,833
Excess of revenues over direct operating expenses	$ 9,801	$ 15,869
Dos Hermanos		

Revenues	$	4,622	$	3,999
Excess of revenues over direct operating expenses	$	1,586	$	1,598
Sun TSH				
Revenues	$	4,739	$	—
Excess of revenues over direct operating expenses	$	3,460	$	—
Ward County				
Revenues	$	1,059	$	—
Excess of revenues over direct operating expenses	$	640	$	—

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. As the accounts receivable was deemed uncollectible, we wrote off the receivable against the allowance during the year ended December 31, 2009.

4. Credit Facilities and Long-Term Debt

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

			Amount Outstanding December 31,	
Description	Interest Rate	Maturity Date	2009	2008
			(in thousands)	
Senior secured reserve-based credit facility	Variable (1)	October 1, 2012	$ 129,800	$ 135,000
Total			$ 129,800	$ 135,000

(1) Variable interest rate was 2.7% and 3.8% at December 31 2009 and 2008, respectively.

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 the bank’s petroleum engineers) of estimated future net cash flows from certain proved natural gas, natural gas liquids and oil reserves of the Company. The reserve-based credit facility is secured by a first lien security interest in all of the Company’s natural gas and oil properties. Additional borrowings were made in January 2008 pursuant to the acquisition of natural gas and oil properties in the Permian Basin. In February 2008, our reserve-based credit facility was amended and restated to extend the maturity from January 3, 2011 to March 31, 2011, increase the maximum facility amount from $200.0 million to $400.0 million, increase our borrowing base from $110.5 million to $150.0 million and add two additional financial institutions as lenders, Wachovia Bank, N.A. and The Bank of Nova Scotia. In May 2008, our reserve-based credit facility was amended in response to a potential acquisition that ultimately did not occur. As a result, none of the provisions included in this amendment went into effect. In July 2008 an additional $30.0 million was borrowed to fund a portion of the cash consideration paid in the Dos Hermanos acquisition and in October 2008, we amended our reserve-based credit facility, which set our borrowing base under the facility at $175.0 million pursuant to our semi-annual redetermination and added a new lender, BBVA Compass Bank. In February 2009, our reserve-based credit facility was amended to allow us to repurchase up to $5.0 million of our own units. In May 2009, our borrowing base was set at $154.0 million pursuant to our semi-annual redetermination. In June 2009, a fourth amendment to our reserve-based credit facility was entered into which temporarily increased the percentage of outstanding indebtedness for which interest rate derivatives could be used. The percentage was increased from 75% to 85% but was to revert back to 75% in one year at June 2010. In August 2009, our reserve-based credit facility was amended and restated to (1) extend the maturity from March 31, 2011 to October 1, 2012, (2) increase our borrowing base from $154.0 million to $175.0 million, (3) increase our borrowing costs, (4) permanently allow 85% of our outstanding indebtedness to be covered under interest rate derivatives, and (5) add two financial institutions as lenders, Comerica Bank and Royal Bank of

Canada. On October 1, 2009, we entered into the First Amendment to our Second Amended and Restated Credit Agreement, which reduced our borrowing base under the reserve-based credit facility from $175.0 million to $170.0 million pursuant to our semi-annual redetermination and changed the definition of majority lenders from 75% to 66.67%. All other terms under the reserve-based credit facility remained the same. In December 2009, our borrowing base was increased from $170.0 million to $195.0 million pursuant to an interim redetermination requested by the Company due to the Ward County acquisition. Indebtedness under the reserve-based credit facility totaled $129.8 million at December 31, 2009.

Interest rates under the reserve-based credit facility are based on Euro-Dollars (LIBOR) or ABR (Prime) indications, plus a margin. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. At December 31, 2009 the applicable margin and other fees increase as the utilization of the borrowing base increases as follows:

Borrowing Base Utilization Grid

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

Our reserve-based credit facility contains a number of customary covenants that require us to maintain certain financial ratios, limit our ability to incur indebtedness, enter into commodity and interest rate derivatives, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, merge or consolidate, engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets, or make distributions to our unitholders when our outstanding borrowings exceed 90% of our borrowing base. At December 31, 2009, 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. See Note 5. Price and Interest Rate Risk Management Activities for further discussion.

5. Price and Interest Rate Risk Management Activities

We have entered into derivative contracts with counterparties that are lenders under our reserve-based credit facility, Citibank N.A., BNP Paribas, The Bank of Nova Scotia, BBVA Compass Bank and Wells Fargo Bank, N.A. (also under the name Wachovia Bank, N.A.), to hedge price risk associated with a portion of our natural gas and oil production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated which has, and could, result in overhedged volumes. Under fixed-priced commodity swap agreements, 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. Put options for natural gas are settled based on the NYMEX price for natural gas at Henry Hub and collars are settled based on a market index selected by us at inception of the contract. We also enter into fixed LIBOR interest rate swap agreements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations to fixed interest rates.

Under ASC Topic 815 "Derivatives and Hedging," all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) in the equity section of the consolidated balance sheets to the extent the hedge is effective. Gains and losses on cash flow hedges included in accumulated other comprehensive income (loss) are reclassified to gains (losses) on commodity cash flow hedges or gains (losses) on interest rate derivative contracts in the period that the related production is delivered or the contract settles. The realized and unrealized gains (losses) on derivative contracts that do not qualify for hedge accounting treatment are recorded as gains (losses) on other commodity derivative contracts or gains (losses) on interest rate derivative contracts in the consolidated statements of operations.

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

In August 2009, in connection with the Sun TSH acquisition, we assumed natural gas puts and swaps based on NYMEX pricing for approximately 61% of the estimated gas production from existing producing wells in the acquired properties for the period beginning August of 2009 through December 2010. In addition, concurrent with the execution of the purchase and sale agreement, the Company entered into a collar for certain volumes in 2010 and a series of collars for a substantial portion of the expected gas production for 2011 at prices above the then current market with a total cost to the Company of $3.1 million, which was financed through deferred premiums.

In December 2009, in an effort to support stable cash flows from the Ward County acquisition, we entered into crude oil swaps based on NYMEX pricing for approximately 90% of the estimated oil production from existing producing wells in the acquired properties for the period beginning January 2010 through December 2013. In addition, we entered into NYMEX oil swap and collar derivative contracts for the period from January 1, 2012 through December 31, 2013 in order to support the cash flow to be received from oil production in other regions.

At December 31, 2009, the Company had open commodity derivative contracts covering our anticipated future production as follows:

Swap Agreements

	Gas		Oil	
Contract Period	MMBtu	Weighted	Bbls	WTI

		Average Fixed Price		Price
2010	4,731,040	$ 8.66	310,250	$ 85.93
2011	3,328,312	$ 7.83	260,750	$ 86.12
2012	—	$ —	137,250	$ 88.13
2013	—	$ —	118,625	$ 88.42

Collars

	Gas			Oil		
Production Period	MMBtu	Floor	Ceiling	Bbls	Floor	Ceiling
2010	1,607,500	$ 7.73	$ 8.92	—	$ —	$ —
2011	1,933,500	$ 7.34	$ 8.44	—	$ —	$ —
2012	—	$ —	$ —	45,750	$ 80.00	$ 100.25
2013	—	$ —	$ —	45,625	$ 80.00	$ 100.25

Interest Rate Swaps

We enter into interest rate swap agreements, which require exchanges of cash flows that serve to synthetically convert a portion of our variable interest rate obligations 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. In December 2008, we amended three existing interest rate swap agreements and entered into one new agreement which fixed the LIBOR rate at 1.85% on $10.0 million of borrowings through December 2010. The first amended agreement reduced the fixed LIBOR rate from 3.88% to 3.35% on $20.0 million and the maturity was extended two additional years to December 10, 2012. In addition, the second amended agreement reset the notional amount on the March 31, 2011 swap from $10.0 million to $20.0 million and also reduced the rate from 2.66% to 2.08%. The third amended agreement reset the notional amount on the January 31, 2011 swap from $10.0 million to $20.0 million, reduced the rate from 3.00% to 2.38% and also extended the maturity two additional years to 2013.

At December 31, 2009, the Company had open interest rate derivative contracts as follows:

Period:		Notional Amount	Fixed Libor Rates
January 1, 2010 to December 18, 2010	$	10,000,000	1.50%
January 1, 2010 to December 20, 2010	$	10,000,000	1.85%
January 1, 2010 to January 31, 2011	$	20,000,000	3.00% (1)
January 1, 2010 to March 31, 2011	$	20,000,000	2.08%
January 1, 2010 to December 10, 2012	$	20,000,000	3.35%
January 1, 2010 to January 31, 2013	$	20,000,000	2.38%

(1)

In February 2010, we revised the terms on the 3.00%, $20.0 million interest rate swap. See Note 13. Subsequent Events for further discussion.

Balance Sheet Presentation

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Assets:		
Commodity derivatives	$ 34,753	$ 39,875
	$ 34,753	$ 39,875
Liabilities:		
Commodity derivatives	$ (13,405)	$ (1,942)
Interest rate swaps	(2,222)	(2,799)
	$ (15,627)	$ (4,741)

By using derivative instruments to economically hedge exposures to changes in commodity prices and interest rates, we expose ourselves to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk. Our counterparties are participants in our reserve-based credit facility (See Note 4. Credit Facilities and Long-Term Debt for further discussion) which is secured by our natural gas and oil properties; therefore, we are not required to post any collateral. The maximum amount of loss due to credit risk that we would incur if our counterparties failed completely to perform according to the terms of the contracts, based on the gross fair value of financial instruments, was approximately $34.8 million at December 31, 2009.

We minimize the credit risk in derivative instruments by: (i) entering into derivative instruments only with counterparties that are also lenders in our reserve-based credit facility and (ii) monitoring the creditworthiness of our counterparties on an ongoing basis. In accordance with our standard practice, our commodity and interest rate swap derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of such loss is somewhat mitigated as of December 31, 2009.

Gain (Loss) on Derivatives

Realized gains (losses) represent amounts related to the settlement of other commodity and interest rate derivative contracts. Unrealized gains (losses) represent the change in fair value of other commodity and interest rate derivative contracts that will settle in the future and are non-cash items.

The following presents our reported gains and losses on derivative instruments at December 31,:

	2009	2008
	(in thousands)	
Realized gains (losses):		
Other commodity derivatives	$ 29,993	$ (6,552)
Interest rate swaps	(1,903)	(107)
	$ 28,090	$ (6,659)
Unrealized gains (losses):		
Other commodity derivatives	$ (19,043)	$ 39,029
Interest rate swaps	763	(3,178)
	$ (18,280)	$ 35,851
Total gains (losses):		

Other commodity derivatives	$	10,950	$	32,477
Interest rate swaps		(1,140)		(3,285)
	$	9,810	$	29,192

There were no reported gains of losses on other commodity derivative contracts or interest rate derivative contracts during the year ended December 31, 2007 as the Company was utilizing hedge accounting and the unrealized gain or loss on derivatives was deferred in accumulated other comprehensive income (loss) in the equity section of the consolidated balance sheets.

6. Fair Value Measurements

As discussed in Note 1. Summary of Significant Accounting Policies (b), we adopted ASC Topic 820 for financial assets and financial liabilities as of January 1, 2008 and for non-financial assets and liabilities as of January 1, 2009. ASC Topic 820 does not expand the use of fair value measurements, but rather, provides a framework for consistent measurement of fair value for those assets and liabilities already measured at fair value under other accounting pronouncements. Certain specific fair value measurements, such as those related to share-based compensation, are not included in the scope of ASC Topic 820. Primarily, ASC Topic 820 is applicable to assets and liabilities related to financial instruments, to some long-term investments and liabilities, to initial valuations of assets and liabilities acquired in a business combination, and to long-lived assets written down to fair value when they are impaired. 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. ASC Topic 820 applies to assets and liabilities carried at fair value on the consolidated balance sheet, as well as to supplemental fair value information about financial instruments not carried at fair value.

The estimated fair values of 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, phantom unit compensation accrual, accrued ad valorem taxes and accrued expense. The carrying amounts approximate fair value due to the short maturity of these instruments.

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

We have applied the provisions of ASC Topic 820 to assets and liabilities measured at fair value on a recurring basis. This includes natural gas, oil and interest rate derivatives contracts. ASC Topic 820 provides a definition of fair value and a framework for measuring fair value, as well as expanding disclosures regarding fair value measurements. The framework requires fair value measurement techniques to include all significant assumptions that would be made by willing participants in a market transaction. These assumptions include certain factors not consistently provided for previously by those companies utilizing fair value measurement; examples of such factors would include our own credit standing (when valuing liabilities) and the buyer's risk premium. In adopting ASC Topic 820, we determined that the impact of these additional assumptions on fair value measurements did not have a material effect on our financial position or results of operations.

ASC Topic 820 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. ASC Topic 820 provides a hierarchy of fair value measurements, based on the inputs to the fair value estimation process. It requires disclosure of fair values classified according to the "levels" described below. The hierarchy is based on the reliability of the inputs used in estimating fair value and requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The framework for fair value measurement assumes that transparent "observable" (Level 1) inputs generally provide the most reliable evidence of fair value and should be used to measure fair value whenever available. The classification of a fair value measurement is determined based on the lowest level (with Level 3 as 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 ASC Topic 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. Our commodity derivative instruments consist of swaps and collars. 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 value of the collar contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters. The discount rate used in the discounted cash flow projections is based on published LIBOR rates, Eurodollar futures rates and interest swap rates. In order to estimate the fair value of our interest rate swaps, we use a yield curve based on money market rates and interest rate swaps, extrapolate a forecast of future interest rates, estimate each future cash flow, derive discount factors to value the fixed and floating rate cash flows of each swap, and then discount to present value all known (fixed) and forecasted (floating) swap cash flows. Curve building and discounting techniques used to establish the theoretical market value of interest bearing securities are based on readily available money market rates and interest rate swap market data. To extrapolate future cash flows, discount factors incorporating our counterparties' and our credit standing are used to discount future cash flows. We have classified the fair values of all our derivative contracts as Level 2.

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

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

	December 31, 2008			
	Fair Value Measurements Using			Assets/Liabilities
	Level 1	Level 2	Level 3	at Fair value
	(in thousands)			
Assets:				
Commodity derivative contracts	$ —	$ 37,933	$ —	$ 37,933
Total derivative instruments	$ —	$ 37,933	$ —	$ 37,933
Liabilities:				
Interest rate derivative contracts	$ —	$ (2,799)	$ —	$ (2,799)
Total derivative instruments	$ —	$ (2,799)	$ —	$ (2,799)

On January 1, 2009, we adopted the previously-deferred provisions of ASC Topic 820 for nonfinancial assets and liabilities, which are comprised primarily of asset retirement costs and obligations initially measured at fair value in accordance with ASC Topic 410 Subtopic 20 "Asset Retirement Obligations" ("ASC Topic 410-20"). These assets and liabilities are recorded at fair value when incurred but not re-measured at fair value in subsequent periods. We classify such initial measurements as Level 3 since certain significant unobservable inputs are utilized in their determination. A reconciliation of the beginning and ending balance of our asset retirement obligations is presented in Note 7, in accordance with ASC Topic 410-20. During the year ended December 31, 2009, in connection with natural gas and oil properties acquired in the Sun TSH and Ward County acquisitions, we incurred and recorded asset retirement obligations totaling $2.5 million at fair value. The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Inputs to the valuation include: (1) estimated plug and abandonment cost per well based on our experience; (2) estimated remaining life per well based on average reserve life per field; (3) our credit-adjusted risk-free interest rate ranging between 2.4% and 3.2%; and (4) the average inflation factor (2.4%). The adoption of ASC Topic 820 on January 1, 2009, as it relates to nonfinancial assets and nonfinancial liabilities, did not have a material impact on our financial position or results of operations.

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:

	2009	2008
	(in thousands)	
Asset retirement obligation at January 1,	$ 2,134	$ 190
Liabilities added during the current period	2,504	1,882
Accretion expense	123	62
Revisions of estimate	(341)	—
Asset retirement obligation at December 31,	$ 4,420	$ 2,134

Accretion expense for the years ended December 31, 2009, 2008 and 2007 was $122,519, $61,683 and $12,558, respectively.

8. Related Party Transactions

In Appalachia, we rely on Vinland to execute our drilling program, operate our wells and gather our natural gas. Pursuant to amended agreements effective March 1, 2009, we reimburse Vinland $95 per well per month (in addition to normal third party operating costs) for operating our current natural gas and oil properties in Appalachia under a Management Services Agreement (“MSA”) which costs are reflected in our lease operating expenses. Also, pursuant to amended agreements effective March 1, 2009, Vinland receives a fee based upon the actual costs incurred by Vinland to provide gathering and transportation services plus a $0.05 per Mcf margin. This transportation fee only encompasses transporting the natural gas to third party pipelines at which point additional transportation fees to natural gas markets would apply. These transportation fees are outlined under a Gathering and Compression Agreement (“GCA”) with Vinland and are reflected in our lease operating expenses. For the years ended December 31, 2009, 2008 and 2007, costs incurred under the MSA were $1.6 million, $0.6 million and $0.5 million, respectively and costs incurred under the GCA were $1.2 million, $1.0 million and $1.2 million, respectively. A payable of $1.4 million and $2.6 million, respectively, is reflected on our December 31, 2009 and 2008 consolidated balance sheets in connection with these agreements and direct expenses incurred by Vinland related to the drilling of new wells and operations of all of our existing wells in Appalachia.

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. On April 1, 2009, we and our wholly-owned subsidiary, TEC, exchanged several wells and lease interests (the “Asset Exchange”) with Vinland, Appalachian Royalty Trust, LLC, and Nami Resources Company, L.L.C. (collectively, the “Nami Companies”). Each of the Nami Companies is beneficially owned by Majeed S. Nami, who, as of December 31, 2009, beneficially owned 15.2% of our common units representing limited liability company interests. In the Asset Exchange, we assigned well, strata and leasehold interests with internal estimated future cash flows of approximately $2.7 million discounted at ten percent, and received well, strata, and leasehold interests with an approximately equal value; therefore no gain or loss was recognized.

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.

As part of the separation of Nami Resources Company, LLC, 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 1.7% of our estimated proved reserves as of December 31, 2009. 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

Basic earnings per unit is computed in accordance with ASC Topic 260 "Earnings Per Share" ("ASC Topic 260"), by dividing net income (loss) attributable to unitholders by the weighted average number of units outstanding during the period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. We use the treasury stock method to determine the dilutive effect. As of December 31, 2009, we have two classes of units outstanding: (i) units representing limited liability company interests ("common units") listed on NYSE under the symbol VNR and (ii) Class B units, issued to management and an employee as discussed in Note 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 granted to officers under our long-term incentive plan did not have a dilutive effect as the Company had a net loss for the years ended December 31, 2009 and 2008 and the exercise price was higher than the average market price for the years ended December 31, 2008 and 2007; therefore, they have been excluded in the computation of diluted earnings per unit. In addition, the phantom units granted to officers under our long-term incentive plan did not have a dilutive effect as even though there is a liability at December 31, 2009 and the officers have elected to have a portion of the liability satisfied in units, the units issued to officers will be from units held by VNRH in an investment account and no new units will be issued.

In accordance with ASC Topic 260, dual presentation of basic and diluted earnings per unit has been presented in the consolidated statements of operations for the years ended December 31, 2009, 2008 and 2007 including each class of units issued and outstanding at that date: common units and Class B units. Net income (loss) per unit is allocated to the common units and the Class B units on an equal basis.

11. Unit-Based Compensation

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

In October 2007, one board member was granted 5,000 common units and in February 2008, three board members were granted 5,000 common units each of which vested after one year. Additionally, in October 2007, two officers were granted options to purchase an aggregate of 175,000 units under our long-term incentive plan with an exercise price equal to the initial public offering price of $19.00 which vested immediately upon being granted and had a fair value of $0.1 million on the date of grant. The grant date fair value for these option awards was calculated in accordance with ASC Topic 718 "Compensation-Stock Compensation" ("ASC Topic 718"), by calculating the Black-Scholes value of each option, using a volatility rate of 12.18%, an expected dividend yield of 8.95% and a discount rate of 5.12%, and multiplying the Black-Scholes value by the number of options awarded. In determining a volatility rate of 12.18%, the Company, due to a lack of historical data regarding the Company's common units, used the historical volatility of the Citigroup MLP Index over the 365 day period prior to the date of grant.

On January 1, 2009 and March 27, 2008, in accordance with their previously negotiated employment agreements, phantom units were granted to two officers in amounts equal to 1% of our units outstanding at January 1, 2009 and 2008. The 2008 phantom units expired on December 31, 2008 and no liability or expense was recognized as there was no appreciation in the value of the units. The amount paid in connection with the 2009 phantom units, was paid in cash and in units at the election of the officers and is equal to the appreciation in value of the units from the date of the grant until the determination date (December 31, 2009), plus cash distributions paid on the units, less an 8% hurdle rate. At December 31, 2009, an accrued liability and unit-based compensation expense of $4.3 million has been recognized in the selling, general and administrative expense line item in the consolidated statement of operations, of which $0.4 million is non-cash compensation expense.

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

These common units, Class B units, options and phantom units were granted as partial consideration for services to be performed under employment contracts and thus will be subject to accounting for these grants under ASC Topic 718. The fair value of restricted units issued is determined based on the fair market value of common units on the date of the grant. This value is amortized over the vesting period as referenced above. A summary of the status of the non-vested units as of December 31, 2009 is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2008	435,000	$ 18.52
Granted	37,950	$ 8.07
Vested	(380,000)	$ (17.95)
Non-vested units at December 31, 2009	92,950	$ 14.54

At December 31, 2009, there was approximately $0.2 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over an average period of approximately 0.2 years. Our consolidated statements of operations reflects non-cash compensation of $2.5 million, $3.6 million and $2.1 million in the selling, general and administrative expenses line item for the years ended December 31, 2009, 2008 and 2007, respectively.

Unit-based awards were made in conjunction with new employment agreements with two executives in February 2010. See Note 13. Subsequent Events for further discussion.

12. Shelf Registration Statement

During the third quarter 2009, we filed a registration statement with the SEC which registered offerings of up to $300.0 million of any combination of debt securities, common units and guarantees of debt securities by our subsidiaries. Net proceeds, terms and pricing of the offering of securities issued under the shelf registration statement will be determined at the time of the offerings. The shelf registration statement does not provide assurance that we will or could sell any such securities. Our ability to utilize the shelf registration statement for the purpose of issuing, from time to time, any combination of debt securities or common units will depend upon, among other things, market conditions and the existence of investors who wish to purchase our securities at prices acceptable to us.

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

As a result of these offerings, we have approximately $197.4 million remaining available under our 2009 shelf registration statement as of December 31, 2009.

13. Subsequent Events

In February 2010, we extended the terms of a $20.0 million interest rate swap for two additional years to January 31, 2013 and reduced the rate from 3.00% to 2.66%.

In February 2010, the Company and VNRH entered into second amended and restated Executive Employment Agreements (the “Amended Agreements”) with two executives. The Amended Agreements were effective January 1, 2010 and will continue until January 1, 2013, with subsequent one year renewals in the event that neither the Company, VNRH nor the executives have given notice to the other parties that the agreements should not be extended. The Amended Agreements provide for an annual base salary and include an annual bonus structure for the executives. The annual bonus will be composed of two company performance elements, absolute target distribution growth and relative unit performance to peer group, as well as a third discretionary element to be determined by the Company’s board of directors. Each of the three components will comprise an equal one-third of each annual bonus. The annual bonus does not require a minimum payout, although the maximum payout may not exceed two times the respective executive’s annual base salary.

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

The phantom units are also subject to a three year vesting period, although the vesting is not pro-rata, but a one-time event which shall occur on the three year anniversary of the date of grant so long as the executive remains continuously employed with the Company during such time. The phantom units are accompanied by dividend equivalent rights, which entitle the executives to receive the value of any dividends made by the Company on its units generally with respect to the number of phantom shares that executive received pursuant to this grant. In the event the executive is terminated for “Cause” (as such term is defined in the Amended Agreement), all phantom units, whether vested or unvested, will be forfeited. The phantom units, once vested, shall be settled upon the earlier to occur of (a) the occurrence of a “Change of Control,” (as defined in the LTIP), or (b) the executive’s separation from service.

Vanguard Natural Resources, LLC and Subsidiaries
Notes to Consolidated Financial Statements
December 31, 2009

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)				
2009					
Natural gas, natural gas liquids and oil sales	$ 9,202	$ 9,404	$ 11,324	$ 16,105	$ 46,035
Loss on commodity cash flow hedges	(896)	(378)	(463)	(643)	(2,380)
Realized gain (loss) on other commodity derivative contracts	7,820	7,964	8,010	6,199	29,993
Unrealized gain (loss) on other commodity derivative contracts	9,829	(14,101)	(12,220)	(2,551)	(19,043)
Total revenues	25,955	2,889	6,651	19,110	54,605
Impairment of natural gas and oil properties	63,818	—	—	46,336	110,154
Other costs and expenses (1)	10,710	9,285	9,705	12,051	41,751
Total costs and expenses	74,528	9,285	9,705	58,387	151,905
Gain on acquisition of natural gas and oil properties	—	—	5,878	1,103	6,981
Net income (loss)	(49,965)	(6,768)	701	(39,703)	(95,735)
Net income (loss) per unit:					
Common & Class B units – basic	$ (3.98)	$ (0.54)	$ 0.05	$ (2.31)	$ (6.74)
Common & Class B units – diluted	$ (3.98)	$ (0.54)	$ 0.05	$ (2.31)	$ (6.74)
2008					
Natural gas, natural gas liquids 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
Realized gain (loss) on other commodity derivative contracts	(1,562)	(5,859)	(2,989)	3,858	(6,552)
Unrealized gain (loss) on other commodity derivative contracts	(20,210)	(52,186)	66,353	45,072	39,029
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)	7,451	8,696	10,495	11,060	37,702
Total costs and expenses	7,451	8,696	10,495	69,947	96,589
Net income (loss)	(15,932)	(47,020)	$ 71,809	$ (12,609)	$ (3,752)
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)

(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, natural gas liquids and oil producing activities and related accumulated depletion, amortization and accretion were as follows at December 31:

	2009	2008
	(in thousands)	
Aggregate capitalized costs relating to natural gas, natural gas liquids and oil producing activities	$ 399,212	$ 284,447
Aggregate accumulated depletion, amortization and accretion	(226,687)	(102,178)
Net capitalized costs	$ 172,525	$ 182,269
ASC Topic 410-20 asset retirement obligations	$ 4,420	$ 2,134

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

	2009	2008	2007
		(in thousands)	
Property acquisition costs	$ 106,776	$ 128,324	$ 3,670
Development costs	5,825	19,097	12,860
Total cost incurred	$ 112,601	$ 147,421	$ 16,530

No internal costs were capitalized in 2009, 2008 or 2007. Additionally, capitalized interest of $58,960 and $75,672 for the years ended December 31, 2008 and 2007, respectively, are included in the table above. There was no capitalized interest in 2009.

Net quantities of proved developed and undeveloped reserves of natural gas and oil and changes in these reserves at December 31, 2009, 2008 and 2007 are presented below. Information in these tables is based on reserve reports prepared by our independent petroleum engineers, Netherland, Sewell & Associates, Inc. for 2009, 2008 and 2007 and DeGolyer and MacNaughton in 2009.

	Gas (in Mcf)	Oil (in Bbls)	NGL (in Bbls)
Net proved reserves			
January 1, 2007	94,184,665	342,968	—
Revisions of previous estimates	(2,073,103)	56,973	—
Conveyance of Reserves from Restructuring	(29,870,272)	(56,175)	—
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	—
Revisions of previous estimates	(36,569,334)	(764,361)	764,176
Extensions, discoveries and other	3,190,928	66,227	—
Purchases of reserves in place	39,832,181	2,908,923	2,900,758
Production	(4,542,374)	(345,400)	(114,784)
December 31, 2009	83,148,498	6,412,748	3,550,150
Proved developed reserves			
December 31, 2007	48,897,929	233,507	—
December 31, 2008	58,315,899	3,766,394	—
December 31, 2009	54,129,281	4,765,599	2,360,526
Proved undeveloped reserves			
December 31, 2007	16,230,537	102,520	—
December 31, 2008	22,921,198	780,965	—
December 31, 2009	29,019,217	1,647,149	1,189,624

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. During 2007, natural gas and oil proved reserves were reduced by 29.8 Bcf and 56.1 Bbls, respectively, due to the value of the 60% interest in proved undeveloped properties which was conveyed to Vinland in the Restructuring. The initial application of the new rules related to modernizing reserve calculations and disclosure requirements resulted in a downward adjustment of 10.6 Bcfe to our total proved reserves and a downward adjustment of $152.2 million to the standardized measure of discounted future net cash flows as of December 31, 2009. Approximately 14.2 Bcfe of this downward adjustment is attributable to the new requirement that 12-month average prices, instead of end-of-period prices, are used in estimating our quantities of proved oil and natural gas reserves. Additional proved undeveloped reserves of 3.6 Bcfe were added as a result of new SEC rules that allow for additional drilling locations to be classified as proved undeveloped reserves assuming such locations are supported by reliable technologies. No proved undeveloped reserves were removed that exceeded the five year development limitation on proved undeveloped reserves imposed by the new rules. The downward adjustment of 10.6 Bcfe to our total proved reserves due to the new SEC rules was more than offset by a 74.7 Bcfe increase in our reserves due to acquisitions completed during the year ended December 31, 2009.

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, 2009.

Our proved undeveloped reserves at December 31, 2009, as estimated by our independent petroleum engineers, were 46.0 Bcfe, consisting of 1.6 million barrels of oil, 29.0 MMcf of natural gas and 1.2 million barrels of natural gas liquids. In 2009, we developed approximately 0.5% of our total proved undeveloped reserves booked as of December 31, 2008 through the drilling of one gross (0.45 net) well at an aggregate capital cost of approximately $0.3 million. None of our proved undeveloped reserves at December 31, 2009 have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves. At December 31, 2009, there are 18 locations with 3.9 Bcfe of proved undeveloped reserves in South Texas that are scheduled to be drilled on a date more than five years from the date the reserves were initially booked as proved undeveloped since we have a contractual arrangement with the operator to drill only 14 wells per year.

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

	2009	2008	2007
		(in thousands)	
Production revenues (1)	$ 73,648	$ 62,543	$ 33,838
Production costs (2)	(16,722)	(15,800)	(7,120)
Depreciation, depletion and amortization	(14,440)	(14,812)	(8,960)
Impairment of natural gas and oil properties	(110,154)	(58,887)	—

Results of operations from producing activities	$ (67,668)	$ (26,956)	$ 17,758

(1) Production revenues include gains and losses on commodity cash flow hedges in 2009, 2008 and 2007 and realized gains and losses on other commodity derivative contracts in 2009 and 2008.

(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:

	2009	2008	2007
		(in thousands)	
Future cash inflows	$ 846,196	$ 739,560	$ 587,639
Future production costs	(362,386)	(258,948)	(173,485)
Future development costs	(95,297)	(50,268)	(36,842)
Future net cash flows	388,513	430,344	377,312
10% annual discount for estimated timing of cash flows	(209,840)	(240,271)	(226,315)
Standardized measure of discounted future net cash flows	$ 178,673	$ 190,073	$ 150,997

For the December 31, 2009 calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using the average natural gas and oil price based upon the 12-month average price of $3.87 per MMBtu for natural gas and $ 61.04 per barrel of crude oil adjusted for quality, transportation fees and a regional price differential. The effect of this change in method decreased the standardized measure of discounted future net cash flow by $152.2 million. 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:

	Year Ended December 31, (1)		
	2009	2008	2007
		(in thousands)	
Sales and transfers, net of production costs	$ (29,313)	$ (53,050)	$ (26,718)
Net changes in prices and production costs	(21,697)	(20,385)	52,625
Extensions discoveries and improved recovery, less related costs	1,673	13,036	10,791
Changes in estimated future development costs	2,557	(12,056)	18,045
Previously estimated development costs incurred during the period	5,825	19,956	16,531
Revision of previous quantity estimates	(64,155)	(10,149)	(75,071)
Accretion of discount	19,007	15,100	14,882
Purchases of reserves in place	80,776	82,454	4,249
Change in production rates, timing and other	(6,073)	4,170	(13,158)
Net change	$ (11,400)	$ 39,076	$ 2,176

(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

None.

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.

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 have concluded that the Company's internal controls over financial reporting were effective at the reasonable assurance level at December 31, 2009.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009, is set forth in Item 9A(b) below.

BDO Seidman, LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009, as stated in their report in Item 9A(d) below.

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

Our management is responsible for establishing and maintaining effective 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 and procedures may deteriorate.

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, 2009. 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, 2009. The effectiveness of our internal control over financial reporting as of December 31, 2009 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

There were no changes in our internal control over financial reporting during the fourth quarter of 2009 that have 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, 2009, 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 Annual 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, 2009, 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 sheets of Vanguard Natural Resources LLC as of December 31, 2009 and 2008 and the related consolidated statements of operations, comprehensive loss, members' equity, and cash flows for each of the years then ended and our report dated March 5, 2010 expressed an unqualified opinion thereon.

/s/ BDO Seidman, LLP

Houston, Texas
March 5, 2010

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, 2009.

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, 2009.

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, 2009.

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, 2009.

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, 2009.

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:

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Reports of Independent Registered Public Accounting Firms	68
Consolidated Statements of Operations	70
Consolidated Balance Sheets	71
Consolidated Statements of Members' Equity	72
Consolidated Statements of Cash Flows	74
Consolidated Statements of Comprehensive Loss	76
Notes to Consolidated Financial Statements	77

(b) Exhibits

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

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
3.1	Certificate of Formation of Vanguard Natural Resources, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
3.2	Second Amended and Restated Limited Liability Company Agreement of Vanguard Natural Resources, LLC (including specimen unit certificate for the units)	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.1+	Vanguard Natural Resources, LLC Long-Term Incentive Plan	Form 8-K, filed October 24, 2007 (File No. 001-33756)
10.2+	Form of Vanguard Natural Resources, LLC Long-Term Incentive Plan Phantom Options Grant Agreement	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.3+	Vanguard Natural Resources, LLC Class B Unit Plan	Form 8-K, filed October 24, 2007 (File No. 001-33756)
10.4+	Form of Vanguard Natural Resources, LLC Class B Unit Plan Restricted Class B Unit Grant	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.5	Management Services Agreement, effective January 5, 2007, by and between Vinland Energy Operations, LLC, Vanguard Natural Gas, LLC, Trust Energy Company, LLC and Ariana Energy, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.6	Participation Agreement, effective January 5, 2007, by and between Vinland Energy Eastern,	Form S-1/A, filed April 25, 2007 (File No. 333-142363)

	LLC, Vanguard Natural Gas, LLC, Trust Energy Company, LLC and Ariana Energy, LLC	
10.7	Gathering and Compression Agreement, effective January 5, 2007, by and between Vinland Energy Gathering, LLC, Vinland Energy Eastern, LLC, Vanguard Natural Gas, LLC and Ariana Energy, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.8	Gathering and Compression Agreement, effective January 5, 2007, by and between Vinland Energy Gathering, LLC, Vinland Energy Eastern, LLC, Vanguard Natural Gas, LLC and Trust Energy Company	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.9	Gathering and Compression Agreement, effective January 5, 2007, by and between Vinland Energy Gathering, LLC and Nami Resources Company, L.L.C.	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.10	Well Services Agreement, effective January 5, 2007, by and between Vinland Energy Operations, LLC, Vanguard Natural Gas, LLC and Ariana Energy, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.11	Well Services Agreement, effective January 5, 2007, by and between Vinland Energy Operations, LLC, Vanguard Natural Gas, LLC and Trust Energy Company, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.12	Well Services Agreement, effective January 5, 2007, by and between Vinland Energy Operations, LLC and Nami Resources Company, L.L.C.	Form S-1/A, filed April 25, 2007 (File No. 333-142363)

10.13	Amended and Restated Operating Agreement by and between Vinland Energy Operations, LLC, Vinland Energy Eastern, LLC and Ariana Energy, LLC, dated October 2, 2007 and effective as of January 5, 2007	Form S-1/A, filed October 22, 2007 (File No. 333-142363)
10.14	Operating Agreement, effective January 5, 2007, by and between Vinland Energy Operations, LLC, Vinland Energy Eastern, LLC and Trust Energy Company, LLC	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.15	Amended and Restated Indemnity Agreement by and between Nami Resources Company, L.L.C., Vinland Energy Eastern, LLC, Trust Energy Company, LLC, Vanguard Natural Gas, LLC and Vanguard Natural Resources, LLC, dated September 11, 2007	Form S-1/A, filed September 18, 2007 (File No. 333-142363)
10.16	Revenue Payment Agreement by and between Nami Resources Company, L.L.C. and Trust Energy Company, dated April 18, 2007 and effective as of January 5, 2007	Form S-1/A, filed August 21, 2007 (File No. 333-142363)
10.17	Gas Supply Agreement, dated April 18, 2007, by and between Nami Resources Company, L.L.C. and Trust Energy Company	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.18	Registration Rights Agreement, dated April 18, 2007, between Vanguard Natural Resources, LLC and the private investors named therein	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.19	Purchase Agreement, dated April 18, 2007, between Vanguard Natural Resources, LLC, Majeed S. Nami and the private investors named therein	Form S-1/A, filed April 25, 2007 (File No. 333-142363)
10.20	Omnibus Agreement, dated October 29, 2007, among Majeed S. Nami, Vanguard Natural Resources, LLC, Vanguard Natural Gas, LLC, Ariana Energy, LLC and Trust Energy Company, LLC.	Form 8-K, filed November 2, 2007 (File No. 001-33756)
10.21+	Employment Agreement, dated May 15, 2007, by and between Britt Pence, VNR Holdings, LLC and Vanguard Natural Resources, LLC	Form S-1/A, filed July 5, 2007 (File No. 333-142363)
10.22	Natural Gas Contract, dated May 26, 2003, between Nami Resources Company, Inc. and Osram Sylvania Products, Inc.	Form S-1/A, filed August 21, 2007 (File No. 333-142363)
10.23	Natural Gas Purchase Contract, dated December 16, 2004, between Nami Resources Company, LLC and Dominion Field Services, Inc.	Form S-1/A, filed August 21, 2007 (File No. 333-142363)
10.24	Natural Gas Purchase Contract, dated December 28, 2004, between Nami Resources Company, LLC and Dominion Field Services, Inc.	Form S-1/A, filed August 21, 2007 (File No. 333-142363)
10.25+	Director Compensation Agreement	

		Form S-1/A, filed September 18, 2007 (File No. 333-142363)
10.26	Purchase and Sale Agreement, dated December 21, 2007, among Vanguard Permian, LLC and Apache Corporation	Form 8-K/A, filed February 13, 2008 (File No. 001-33756)
10.27	Amended Purchase and Sale Agreement, dated January 31, 2008, among Vanguard Permian, LLC and Apache Corporation	Form 8-K/A, filed February 4, 2008 (File No. 001-33756)
10.28	Amended and Restated Credit Agreement, dated February 14, 2008, by and between Nami Holding Company, LLC, Citibank, N.A., as administrative agent and L/C issuer and the lenders party thereto	Previously filed with our Form 10-K on March 31, 2008
10.29	Purchase and Sale Agreement, dated July 18, 2008, among Vanguard Permian, LLC and Segundo Navarro Drilling, Ltd.	Form 8-K, filed July 21, 2008 (File No. 001-33756)
10.30+	Form of Indemnity Agreement dated August 7, 2008	Previously filed with our Quarterly report on Form 10-Q on August 13, 2008
10.31	Second Amendment to First Amended and Restated Credit Agreement, dated October 22, 2008, by and between Vanguard Natural Gas, LLC, BBVA Compass Bank, as lender, and Citibank, N.A., as administrative agent	Previously filed with our Quarterly report on Form 10-Q on November 14, 2008
10.32	First Amendment to First Amended and Restated Credit Agreement, dated May 15, 2008, by and between Vanguard Natural Gas, LLC, lenders party thereto, and Citibank, N.A., as administrative agent	Previously filed with our Form 10-K on March 11, 2009
10.33	Third Amendment to First Amended and Restated Credit Agreement, dated February 18, 2009, by and between Vanguard Natural Gas, LLC, lenders party thereto, and Citibank, N.A., as administrative agent	Previously filed with our Form 10-K on March 11, 2009
10.34	First Amendment to Gathering and Compression Agreement, dated May 8, 2009, effective March 1, 2009, by and between Vinland Energy Gathering, LLC, Vinland Energy Eastern, LLC, Vanguard Natural Gas, LLC and Trust Energy Company, LLC	Previously filed with our Quarterly report on Form 10-Q on May 11, 2009
10.35	First Amendment to Management Services Agreement, dated May 8, 2009, effective March 1, 2009, by and between Vinland Energy Operations, LLC, Vanguard Natural Gas, LLC, Trust Energy Company, LLC and Ariana Energy, LLC	Previously filed with our Quarterly report on Form 10-Q on May 11, 2009
10.36	Fourth Amendment to First Amended and Restated Credit Agreement, dated June 26, 2009, by and between Vanguard Natural Gas, LLC, lenders party thereto, and Citibank, N.A., as administrative agent	Previously filed with our Quarterly report on Form 10-Q on July 31, 2009

10.37	Purchase and Sale Agreement, dated July 17, 2009, among Vanguard Permian, LLC and Segundo Navarro Drilling, Ltd.	Form 8-K, filed July 21, 2009 (File No. 001-33756)
10.38	Second Amended and Restated Credit Agreement dated August 31, 2009, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto	Form 8-K, filed September 1, 2009 (File No. 001-33756)

10.39	First Amendment to Second Amended and Restated Credit Agreement dated October 14, 2009, by and between Vanguard Natural Gas, LLC, Citibank, N.A., as administrative agent and the lenders party hereto	Previously filed with our Quarterly report on Form 10-Q on November 4, 2009
10.40	Underwriting Agreement dated December 1, 2009, by and among Vanguard Natural Resources, LLC and Citigroup Global Markets Inc., Wells Fargo Securities, LLC and RBC Capital Markets Corporation, as representatives of the several underwriters named therein	Form 8-K, filed December 2, 2009 (File No. 001-33756)
10.41	Purchase and Sale Agreement, Lease Amendment and Lease Royalty Conveyance Agreement and Conveyance Agreement, dated November 27, 2009, among Vanguard Permian, LLC and Fortson Production Company and Benco Energy, Inc.	Form 8-K, filed December 4, 2009 (File No. 001-33756)
10.42+	Second Amended and Restated Employment Agreement, effective January 1, 2010, by and between Scott W. Smith, VNR Holdings, LLC and Vanguard Natural Resources, LLC	Form 8-K, filed February 8, 2010 (File No. 001-33756)
10.43+	Second Amended and Restated Employment Agreement, effective January 1, 2010, by and between Scott W. Smith, VNR Holdings, LLC and Vanguard Natural Resources, LLC	Form 8-K, filed February 8, 2010 (File No. 001-33756)
10.44+	Restricted Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC. and Scott W. Smith	Form 8-K, filed February 8, 2010 (File No. 001-33756)
10.45+	Restricted Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC. and Richard A. Robert	Form 8-K, filed February 8, 2010 (File No. 001-33756)
10.46+	Phantom Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC. and Scott W. Smith	Form 8-K, filed February 8, 2010 (File No. 001-33756)
10.47+	Phantom Unit Award Agreement, by and between Vanguard Natural Resources, LLC, VNR Holdings, LLC. and Richard A. Robert	Form 8-K, filed February 8, 2010 (File No. 001-33756)
16.1	Letter re change in certifying accountant	Form 8-K, filed on September 2, 2008 (File No. 001-33756)
21.1		Filed herewith

	List of subsidiaries of Vanguard Natural Resources, LLC	
23.1	Consent of BDO Seidman, LLP, Independent Registered Public Accounting Firm	Filed herewith
23.2	Consent of UHY LLP, Independent Registered Public Accounting Firm	Filed herewith
23.3	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists	Filed herewith
23.4	Consent of DeGolyer and MacNaughton, Independent Petroleum Engineers and Geologists	Filed herewith
24.1	Power of Attorney (included on signature page hereto)	Filed herewith
31.1	Certification of Chief Executive Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists	Filed herewith
99.2	Report of DeGolyer and MacNaughton, Independent Petroleum Engineers and Geologists	Filed herewith

+ Management Contract or Compensatory Plan or Arrangement required to be filed as an exhibit hereto pursuant to item 601 of Regulation S-K.

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 5th day of March, 2010.

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 5, 2010	/s/ Scott W. Smith Scott W. Smith President, Chief Executive Officer and Director (Principal Executive Officer)
March 5, 2010	/s/ Richard A. Robert Richard A. Robert Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
March 5, 2010	/s/ W. Richard Anderson W. Richard Anderson Director

March 5, 2010	/s/ Bruce W. McCullough Bruce W. McCullough Director
March 5, 2010	/s/ John R. McGoldrick John R. McGoldrick Director
March 5, 2010	/s/ Loren Singletary Loren Singletary Director
March 5, 2010	/s/ Lasse Wagene Lasse Wagene Director